NEW HAMPSHIRE TECHNICAL REFERENCE MANUAL

for Estimating Savings from Energy Efficiency Measures, 2022 Program Year

Filed March 1st, 2022 by the New Hampshire Utilities

Table of Revisions and Changes

Revision Number	Page	Date	Chapter	Description
1	1-329	1/14/2022	All	Removed "DRAFT" water mark on docu
2	350	1/14/2022	Appendix 1	Added C&I Load Shape table to appendix
3	3	1/14/2022	Table of Contents	Updated table of contents to fix chapter n
4	3	1/14/2022	Table of Contents	Removed tracked changes marking from
5	352	1/14/2022	Revision History	Added "Revision History". Also added re applicable chapter.
6	379	1/14/2022	Appendix 2: EFLH	Added "Appendix 2: Equivalent Full Loa
7	23	1/14/2022	1.0 Active Demand Response – Residential	The deemed savings number for thermost 0.60 kw from 0.67 kw.
8	23	1/14/2022	1.0 Active Demand Response – Residential	Fixed broken links in references
9	27	1/14/2022	1.1Appliances - Advanced Power Strip	Fixed broken links in references.
10	29	1/14/2022	1.2 Appliances – Clothes Dryer	Added savings values for retrofit clothes vendor calculated.
11	32	1/14/2022	1.3 Appliances – Clothes Washer	Added option to use EPA calculator for r were vendor calculated.
12	54	1/14/2022	1.12 Building Shell – Air Sealing	Updated to reference the "Weighted Who shape for air sealing, rather than the hardv shape.
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19	65	1/14/2022	1.14 Building Shell – Door Replacement	Omitted measure added
20	68	1/14/2022	1.15 Building Shell – Window Replacement	Omitted measure added
21	74	1/14/2022	1.17 Hot Water – Heat Pump Water Heater	Measure names of the residential ES prod heater offerings updated to match implem conventions.
22	74	1/14/2022	1.17 Hot Water – Heat Pump Water Heater	Added BC Measure ID’s to encompass al
23	81	1/14/2022	1.19 Hot Water – Setback	Added BC ID’s and HEA and HPwES me fuel type.
24	84	1/14/2022	1.20 Hot Water – Showerhead	Added missing BC measures ID’s to the a energy impact tables.
25	84	1/14/2022	1.20 Hot Water – Showerhead	Updated typos in footnote numbering.
26	88	1/14/2022	1.21 Hot Water –Water Heater	Fixed broken link in reference #3 for Nav Energy Service Impact Evaluation. Prepa administrators in Massachusetts.
27	88	1/14/2022	1.21 Hot Water –Water Heater	Added entries for non-gas water heaters w from the TRM. New entries include BC I E21B1a097, E21B1a099, E21B1a098, E2
28	93	1/14/2022	1.22 HVAC – Boiler	Added omitted measures for Kerosene Bo HEA and HPwES
29	96	1/14/2022	1.23 HVAC – Boiler Reset Control	Removed copy and paste formatting error originally in red text, change to black text
30	103	1/14/2022	1.25 HVAC – Repair and Cleaning	Omitted Measure Added
31	105	1/14/2022	1.26 HVAC – ENERGY STAR Central Air Conditioning	Formatting, added correct BC ID’s

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33	109	1/14/2022	1.27 HVAC – ENERGY STAR Room Air Conditioning	Updated HPwES RR in 'Realization Rate correct in the table, but incorrect in the ve
34	112	1/14/2022	1.28 HVAC – Furnace	Corrected typo in E21B1b007 delta kWh 6.700, should instead match the propane s
35	115	1/14/2022	1.29 HVAC – Central Air-source Heat Pump	Updated SEER to EER conversion factor
36	115	1/14/2022	1.29 HVAC – Central Air-source Heat Pump	Added omitted ductless mini split heating measures
37	120	1/14/2022	1.30 HVAC – Ductless Mini-Split Heat Pump	Updated SEER to EER conversion factor
38	144	1/14/2022	1.36 Thermostat – Programmable	Corrected E21A2b010 G21A2b003 to reflect kWh savings.
39	144	1/14/2022	1.36 Thermostat – Programmable	Corrected realization rate verbiage to refl in the table.
40	148	1/14/2022	1.37 Whole Home – New Construction	Fixed broken link in references
41	153	1/14/2022	1.38 Whole Home – Energy Report	Fixed broken link in references
42	168	1/14/2022	2.3 Compressed Air – Air Nozzle	Fixed broken link in references
43	221	1/14/2022	2.17 Food Service – Ice Machine	Corrected algorithms to provide annualiz baselines
44	221	1/14/2022	2.17 Food Service – Ice Machine	Added other resource impacts.
45	271	1/14/2022	2.32 HVAC- Demand Control Ventilation	Updated midstream and retrofit baselines.
46	271	1/14/2022	2.32 HVAC- Demand Control Ventilation	Fixed broken link.
47	282	1/14/2022	2.36 HVAC – Energy Management System	Corrected baseline from "assumes the rel has no centralized control" to "site specif

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48	284	1/14/2022	2.37 HVAC – Heat and Hot Water Combo Systems	Update baseline. Baseline boiler should b treatment elsewhere in the TRM. 30.5 MM consistent with MA assumptions:
49	289	1/14/2022	2.39 HVAC – Heating Systems – Condensing Unit Heaters	Corrected baseline to reference most curr
50	293	1/14/2022	2.41 HVAC – Heating Systems – Infrared Heater	Corrected baseline to reference most curr
51	295	1/14/2022	2.35 HVAC – High Efficiency Chiller	Added EFLH based on 2015 DNV GL stu previously missing.
52	295	1/14/2022	2.42 HVAC – High Efficiency Chiller	Fixed error under baseline efficiency, hig references section. Document originally la code as "Massachusetts" building code, ra Hampshire". The referenced code, IECC 2 Conservation, and the values listed were c incorrectly labelled with "Massachusetts" reference to the code was updated as it wa
53	308	1/14/2022	2.46 HVAC – Unitary Air Conditioner	Removed algorithms for units with coolin greater than 65 kBtu/h and **IEER availab** are preferred.
54	308	1/14/2022	2.46 HVAC – Unitary Air Conditioner	Updated baseline table for clarity and to r code.
55	316	1/14/2022	2.47 HVAC – Heat Pump Systems	Updated SEER to EER conversion factor
56	334	1/14/2022	2.51 Lighting - Retrofit	Corrected the three typos resulting from a the delta watt column of the upstream ligh table. Updated line items are LED Retrofi kit, low-output w/ sensor and stairwell kit
57	349	1/14/2022	2.53 Motors & Drives - Variable Frequency Drive	Changed the formatting of the algorithm f impact for clarity.
58	99	1/14/2022	1.24 HVAC – Duct Sealing	Omitted gas measures added
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60	190	3/1/2022	2.9 Food Service- Conveyor Broiler	New Measure Added
61	193	3/1/2022	2.10 Food Service-Deck Oven	New Measure Added
62	215	3/1/2022	2.15 Food Service – Hand Wrapper	New Measure Added

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65	248	3/1/2022	2.24 Food Service – Underfired Broiler	New Measure Added
66	105	3/1/2022	1.26 HVAC – Central Air Conditioning	Replaced EFLH value of 385, based on 2 Updated with reference to appendix 2 for on NH TMY3 Data.
67	115	3/1/2022	1.29 HVAC – Central Air-source Heat Pump	Added reference to appendix 2 for new E reference to appendix 2 for new EFLH va Data.
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6	379	3/1/2022	Appendix 2: EFLH	Added “Appendix 2: Equivalent Full Load Hours”.
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23	81	1/14/2022	1.19 Hot Water – Setback	Added BC ID’s and HEA and HPwES measures for the Kerosene fuel type.
24	84	1/14/2022	1.20 Hot Water – Showerhead	Added missing BC measures ID’s to the algorithms for primary energy impact tables.
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71	292	3/1/2022	2.41- HVAC Heating Systems – Infrared Heater	Updated with reference to appendix 2 for new EFLH values based on NH TMY3 Data.
72	292	3/1/2022	2.47 – HVAC Heat Pump Systems	Updated with reference to appendix 2 for new EFLH values based on NH TMY3 Data.

Table of Contents

Introduction

This *New Hampshire Technical Reference Manual for Estimating Savings from Energy Efficiency Measures* ("TRM") documents for regulatory agencies, customers, and other stakeholders how the New Hampshire Utilities consistently, reliably, and transparently calculate savings from the installation of efficient equipment, collectively called "measures." This reference manual provides methods, formulas and default assumptions for estimating energy, peak demand and other resource impacts from efficiency measures.

Within this document, efficiency measures are organized by the sector for which the measure is eligible and by the primary energy source associated with the measure. The three sectors are Residential, Income Eligible, and Commercial & Industrial ("C&I"). The primary energy sources addressed in this technical reference document are electricity and natural gas, and savings from delivered fuels such as oil and propane are also addressed where appropriate.

Each measure is presented in its own section as a measure characterization. The measure characterizations provide mathematical equations for determining savings (algorithms), as well as default assumptions and sources, where applicable. In addition, any descriptions of calculation methods or baselines are provided as appropriate. The parameters for calculating savings are listed in the same order for each measure. The measure calculations and assumptions provided in the TRM will match those found in the Benefit Cost Models ("BC Models") created by utilities. There are some measures in the BC models that we do not currently anticipate incentivizing, and therefore have not been reflected in the TRM. If the opportunity arises to offer them in a cost-effective way, we will update the TRM with entries for these measures at that time.

Algorithms are provided for estimating annual energy and peak demand impacts for primary and secondary energy sources if appropriate. In addition, algorithms or calculated results may be provided for other nonenergy impacts (such as water savings or operation and maintenance cost savings). Inputs and assumptions are based on New Hampshire-specific evaluations or data where available Other factors being equal, New Hampshire jurisdiction-specific results will be favoured over results from other jurisdictions in order to account for differences in climate, hours of use, program design and delivery, market conditions, and evaluation frameworks. However, when relevant results exist both from New Hampshire and from other states, it may be necessary to balance the desirable attributes of state-specificity and data reliability. When considering whether to apply results from a study originating in another jurisdiction to New Hampshire programs, the EM&V Working Group (with support from independent evaluation firms as needed), will make the determination based on (1) the similarity of evaluated program/measures to those offered in NH; (2) the similarity of relevant markets and customers base; (3) the recency of the study relative to the recency of any applicable NH results; and (4) the quality of the study's methodology and sample size. In addition to third-party evaluations, inputs may also be based on sources including manufacturer and industry data, data from government agencies such as the U.S. Department of Energy or Environmental Protection Agency, or credible and realistic factors developed using engineering judgment.

This document will be reviewed and updated annually to reflect changes in technology, baselines and evaluation results.

Reference Tables

PROGRAM ABBREVIATIONS

Commercial	
Energy Rewards RFP Program	RFP
Large Business Energy Solutions	LBES
Municipal Energy Solutions	Muni
Small Business Energy Solutions	SBES
Residential	
ENERGY STAR Homes	ES Homes
ENERGY STAR Products	ES Products
Home Energy Assistance	HEA
Home Energy Reports	HER
Home Performance with ENERGY STAR	HPwES

CATEGORIES

Appliances
Building Shell
Compressed Air
Custom
Food Service
Heating Ventilation and Air Conditioning (HVAC)
Hot Water
Lighting
Motors and Drives
Whole Home

Measure Characterization Structure

This section describes the common entries or inputs that make up each measure characterization. A formatted template follows the descriptions of each section of the measure characterization. A single device or behavior is defined as a measure within each program and fuel. The source of each assumption or default parameter value will be referenced in the endnotes section of each measure chapter.

Measure Code	A unique way to identify a measure where the first set of characters indicates the market, the second set of characters indicates the category, and the third set is an abbreviated code for the measure name.
Market	This is the sector for which the measure is applicable and can be Residential, Income Eligible or C&I.
Program Type	The type of baseline used (i.e., retrofit, lost opportunity).
Category	The category of measure type, based on list above.

Description:

This section will include a plain text description of the energy efficiency measure, including the benefit(s) of its installation.

Baseline Efficiency:

This section will include a statement of the assumed equipment/operation efficiency in the absence of program intervention. Multiple baselines will be provided as needed, e.g., for different markets. Baselines may refer to reference tables or may be presented as a table for more complex measures.

High Efficiency:

This section will describe the high efficiency case from which the energy and demand savings are determined. The high efficiency case may be based on specific details of the measure installation, minimum requirements for inclusion in the program, or an energy efficiency case based on historical participation. It may refer to tables within the measure characterization or in the appendices or efficiency standards set by organizations such as ENERGY STAR® and the Consortium for Energy Efficiency.

Algorithms for Calculating Primary Energy Impact:

This section will describe the method for calculating electric savings and electric demand savings in appropriate units.

The savings algorithm will be provided in a form similar to the following:

$$\Delta kWh = \Delta kW \times Hours$$

Similarly, the method for calculating electric demand savings will be provided in a form similar to the following:

$$\Delta kW = \left(Watts_{BASE} - Watts_{EE}\right)/1000$$

This section also describes any non-electric (gas, propane, oil) savings in appropriate units, i.e., MMBtu associated with the energy efficiency measure, including all assumptions and the method of calculation.

This section will, as appropriate, summarize electric and non-electric savings in a table that contains the following information:

Measure Name: <Name used in utilities' Benefit-Cost models >
Program: <Defined by utilities, also referred to as Program Name>
Savings: <Measure savings in units of kWh, kW, MMBtu, or other as applicable; this information may be contained in multiple fields>

Measure Life:

This section will provide the measure life for each measure and describe the measure life basis, e.g., effective useful life (EUL) or adjusted measure life (AML). It will note any adjustments made, such as for LED market trends.

BC Measure ID	Measure Name	Program	Measure Life
[Unique ID for measures in the utilities' Benefit-Cost model]	[Measure Name]	[Program Abbreviation from list above]	XX

Other Resource Impacts:

If applicable, this section describes any water or ancillary savings associated with the energy efficiency measure, including all assumptions.

Impact Factors for Calculating Adjusted Gross Savings:

The section includes a table of impact factor values for calculating adjusted gross savings. These include in-service rates, realization rates, and coincidence factors. Further descriptions of the impact factors and the sources on which they are based are described below.

ISR = In-Service Rate
CF_{SP} = Peak Coincidence Factor (summer peak)
CF_{WP} = Peak Coincidence Factor (winter peak)
RR_E = Realization Rate, electric(kWh)
RR_{NE} = Realization Rate, non-electric (MMBtu)
RR_{SP} = Realization Rate for summer peak kW
RR_{WP} = Realization Rate for winter peak kW

Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
[Measure Name]	[Program abbreviation]	X.XX	X.XX	n/a	X.XX	X.XX	X.XX	X.XX

<u>In-Service Rates:</u>

Actual portion of efficient units that are installed. For example, efficient lamps may have an in-service rate less than 1.00 since some lamps are purchased as replacement units and are not immediately installed. The ISR is 1.00 for most measures.

Realization Rates:

Used to adjust the gross savings (as calculated by the savings algorithms) based on impact evaluation studies. The realization rate is equal to the ratio of measure savings developed from an impact evaluation to the estimated measure savings derived from the savings algorithms. The realization rate does not include the effects of any other impact factors, unless explicitly noted. Depending on the impact evaluation study, there may be separate Realization Rates for electric energy (kWh), peak demand (kW), or non-electric energy (MMBtu).

Coincidence Factors:

Adjusts the connected load kW savings derived from the savings algorithm. A coincidence factor represents the fraction of the connected load reduction expected to occur at the same time as a particular system peak period. The coincidence factor includes both coincidence and diversity factors combined into one number, thus there is no need for a separate diversity factor in this TRM.

Energy Load Shape:

The section includes a table or reference with the time-of-use pattern of a typical customer's electrical energy consumption for each segment and end use. Because the value of avoided energy varies throughout the year, load shapes are used to allocate energy savings into specific time periods in order to better reflect its time-dependent value. Load shapes are defined as follows based on ISO-NE definitions:

- Summer On-Peak: 7 am to 11 pm, weekdays, during the months of June through September, except ISO-NE holidays;
- Summer Off-Peak: All other hours during the months of June through September (includes weekends and holidays);
- Winter On-Peak: 7 am to 11 pm, weekdays, during the months of October through May, except ISO-NE holidays; and
- Winter Off-Peak: All other hours during the months of October through May (includes weekends and holidays).

Impact Factors for Calculating Net Savings:

The amount of savings attributable to a program or measure. Net savings differs from "Gross Savings" because it includes adjustments from impact factors, such as free-ridership or spillover. The ratio of net savings to gross savings in known as the Net-to-Gross ratio and is usually expressed as a percent.

This section would only apply to midstream and upstream offerings, which are known to have greater levels of free-ridership than other programs as an inherent part of their program design. For other programs, the utilities will prioritize designing programs and putting mechanisms in place to minimize free-riders, in line with precedent from the 1999 NH EE Working Group report, which stated that "program designs should attempt to minimize free-riders" but "the methodological challenges and associated costs of accurately assessing free-riders no longer justifies the effort required".

Non-Energy Impacts:

As discussed with the NH Benefit/Cost Working Group, and per Commission Order,[1] the NH Utilities are applying non-energy impacts (NEIs) in cost-effectiveness screening as follows:

The **Primary Granite State Test** reflects low-income participant NEIs, based on New Hampshire-specific primary research on the Home Energy Assistance program. Specifically, based on the HEA evaluation,[2] a per-project value of $406 reflecting participant NEIs—including increased comfort, decreased noise, and health-related NEIs—will be applied annually to each weatherization project over its 15-year measure life. These NEIs are reflected in the measure chapters for insulation and air sealing.

The **Secondary Granite State Test** reflects sector-level percentage adders for participant NEIs for the residential (non-low-income) and C&I sectors, based on a review of secondary NEI research from similar jurisdictions, adjusted for New Hampshire-specific economic and other factors and matched to New Hampshire's programs and measures.[3] The test also reflects environmental externality NEIs, based on non-embedded avoided cost values from the AESC. These NEI values are not reflected in the TRM measure chapters. For HEA, the same primary research NEI value is applied in the Secondary Granite State Test as in the Primary Granite State Test.

Both the **Primary and Secondary Granite State Tests** reflect other resource impacts for water and delivered fuels, as reflected in the TRM measure chapters.

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[1] Docket No. DE 17-136, Order Approving Benefit Cost Working Group Recommendations, No. 26,322, December 30, 2019; Order Approving 2020 Update Plan, No. 26,323, December 31, 2019.

[2]Opinion Dynamics. Home Energy Assistance Program Evaluation Report 2016-2017, Final, July 29, 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf

[3]DNV-GL. New Hampshire Non-Energy Impacts Database Methodology Memo, April 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/Final-NH-NEI-Methodology-Memo-20200409.pdf; New Hampshire Non-Energy Impacts Database, July 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200722-NH-NEI-Draft-Database-NHML-core.xlsm

Impact Factors for Calculating Adjusted Gross and Net Savings

The New Hampshire Utilities use the algorithms in the Measure Characterization sections to calculate the gross savings for energy efficiency measures. Impact factors are then applied to make various adjustments to the gross savings estimates to account for the performance of individual measures or energy efficiency programs as a whole in achieving energy reductions as assessed through evaluation studies. Impact factors address both the technical performance of energy efficiency measures and programs, accounting for the measured energy and demand reductions realized compared to the gross estimated reductions, as well as in certain cases the programs' effect on the market for energy efficient products and services.

This section describes the types of impact factors used to make such adjustments, and how those impacts are applied to gross savings estimates.

Types of Impact Factors

The impact factors used to adjust savings fall into one of two categories:

Impact factors used to adjust gross savings:
- In-Service Rate ("ISR")
- Realization Rate ("RR")
- Summer and Winter Peak Demand Coincidence Factors ("CF")

Impact factors used to calculate net savings:
- Free-Ridership ("FR") and Spillover ("SO") Rates
- Net-to-Gross Ratios ("NTG")

The **in-service rate** is the actual portion of efficient units that are installed. For example, efficient lamps may have an in-service rate less than 1.00 since some lamps are purchased as replacement units and are not immediately installed. The ISR is 1.00 for most measures.

The **realization rate** is used to adjust the gross savings (as calculated by the savings algorithms) based on impact evaluation studies. The realization rate is equal to the ratio of measure savings developed from an impact evaluation to the estimated measure savings derived from the savings algorithms. The realization rate does not include the effects of any other impact factors. Depending on the impact evaluation study, there may be separate Realization Rates for electric energy (kWh), peak demand (kW), or non-electric energy (MMBtu).

A **coincidence factor** adjusts the connected load kW savings derived from the savings algorithm. A coincidence factor represents the fraction of the connected load reduction expected to occur at the same time as a particular system peak period. The coincidence factor includes both coincidence and diversity factors combined into one number, thus there is no need for a separate diversity factor in this TRM. Coincidence Factors are provided for the on-peak period as defined by the ISO New England for the Forward Capacity Market ("FCM"), and are calculated consistently with the FCM methodology. Electric demand reduction during the ISO New England peak periods is defined as follows:

On-Peak Definition (applicable definition for NH):
- Summer On-Peak: average demand reduction from 1:00-5:00 PM on non-holiday weekdays in June July, and August
- Winter On-Peak: average demand reduction from 5:00-7:00 PM on non-holiday weekdays in December and January

Seasonal Peak Definition (not applied in NH):

- Summer Seasonal Peak: demand reduction when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak forecast for June-August
- Winter Seasonal Peak: demand reduction when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak load forecast for December-January

The values described as Coincidence Factors in the TRM are not always consistent with the strict definition of a Coincidence Factor (CF). It would be more accurate to define the Coincidence Factor as "the value that is multiplied by the Gross kW value to calculate the average kW reduction coincident with the peak periods." For example, a coincidence factor of 1.00 may be used because the coincidence is already included in the estimate of Gross kW; this is often the case when the "Max kW Reduction" is not calculated and instead the "Gross kW" is estimated using the annual kWh reduction estimate and a loadshape model.

The **net savings** value is the final value of savings that is attributable to a measure or program. Net savings differs from gross savings because it includes the effects of the free-ridership and/or spillover rates. Net savings currently apply to midstream and upstream offerings, which are known to have greater levels of free-ridership than other programs as an inherent part of their program design. For other programs, the utilities will prioritize designing programs and putting mechanisms in place to minimize free-riders, in line with precedent from the 1999 NH EE Working Group report, which stated that "program designs should attempt to minimize free-riders" but "the methodological challenges and associated costs of accurately assessing free-riders no longer justifies the effort required".

A **free-rider** is a customer who participates in an energy efficiency program (and gets an incentive) but who would have installed some or all of the same measure(s) on their own, with no change in timing of the installation, if the program had not been available. The free-ridership rate is the percentage of savings attributable to participants who would have installed the measures in the absence of program intervention.

The **spillover rate** is the percentage of savings attributable to a measure or program, but additional to the gross (tracked) savings of a program. Spillover includes the effects of 1) participants in the program who install additional energy efficient measures outside of the program as a result of participating in the program, and 2) non-participants who install or influence the installation of energy efficient measures as a result of being aware of the program. These two components are the participant spillover (SOP) and nonparticipant spillover (SONP).

The **net-to-gross ratio** is the ratio of net savings to the gross savings adjusted by any impact factors (i.e., the "adjusted" gross savings). Depending on the evaluation study, the NTG ratio may be determined from the free-ridership and spillover rates, if available, or it may be a distinct value with no separate specification of FR and SO values.

1. Residential

1.0 Active Demand Response – Residential

Measure Code	[Code]
Market	Residential
Program Type	Custom
Category	Active Demand Response

Description:

Residential Direct Load Control is focused on reducing electrical demand during summer peak load periods by controlling equipment inside a building, such as via wi-fi connected thermostats, communicating domestic hot water heaters and pool pumps, and other controlled energy-using devices.

Residential Storage Daily Dispatch involves customers receiving incentives to decrease demand by discharging energy from storage in response to a signal or communication from the Program Administrators. Residential Storage Daily Dispatch demand response periods may occur during peak hours in summer months.

Summer peak load control periods for both Residential Direct Load Control and Residential Storage Daily Dispatch are three-hour events that may occur between 2:00 p.m. and 7:00 p.m. on non-holiday weekdays between June 1 and September 30.

Baseline Efficiency:

For Direct Load Control, evaluators determined baseline conditions using an experimental design methodology (randomly assigned treatment and control groups), or a within-subject methodology or savings adjustment factor for demand reduction events where experimental design was not possible.
For thermostat controls in the Residential Direct Load Control program, vendor-supplied baselines may use one of several baseline methodologies to determine savings. The assumption in this document is that either the ISO-NE[1] or PJM[2] demand response customer baseline operation models are used by the vendor.

The baseline case for Residential Storage Daily Dispatch is an equivalent residential home with onsite energy storage, including any onsite solar PV production, but without peak demand response control.[3]

High Efficiency:

The high efficiency case is a residential building with devices that are equipped to communicate with the utility to reduce demand during curtailment periods. This could include communicating thermostats, residential storage equipment, or other types of residential demand response equipment.

Note that active demand response is not intended to reduce energy use, but rather to reduce power consumption during demand response periods. As a result, little energy savings are available for Residential Direct Load Control. A small amount of energy savings per demand response event is provided in the section below.

For Residential Storage Daily Dispatch, a negative net kWh impact should be assessed to account for round-trip efficiency losses during the charging and discharging periods.

Algorithms for Calculating Primary Energy Impact:

Thermostat control programs are the most widely implemented, and therefore have the most well-supported savings findings. Ex-post savings are calculated by applying the savings adjustment factor to vendor-reported savings.For vendors that use ISO-NE or PJM baselines to calculate demand savings for central air conditioners controlled by wi-fi connected thermostats, an adjustment to vendor-claimed demand savings based on evaluation results[4] is applied:

$$\Delta kW_{Pre-event} = \left(\Delta kW_{Pre-event,vendor}\right) \times \left(F_{pre-event}\right)$$
$$\Delta kW_{Post-event} = \left(\Delta kW_{Post-event,vendor}\right) \times \left(F_{post-event}\right)$$
$$\Delta kW_{Event} = (\Delta kW_{vendor}) \times (F_{event})$$
$$F_{event} = -3.06 + (0.05 \times Temp_{avg})$$

Where,

Unit	= one dispatched thermostat
$\Delta kW_{Pre-event}$	= demand adjustment for pre-cooling before event
$\Delta kW_{post-event}$	= demand adjustment for recovery cooling after event
$\Delta kW_{pre/post/event,vendor}$	= vendor demand savings in the period of interest (i.e. pre-event, during event, or post-event), typically calculated relative to ISO-NE or PJM baseline
$F_{pre-event}$	= savings adjustment factor in the pre-event period = 0.72[4]
$F_{post-event}$	= savings adjustment factor in the post-event period = 0.68[4]
F_{event}	$= -3.06 + (0.05 \times Temp_{avg})$ [4]
$Temp_{avg}$	= average outdoor air temperature during the event period

.

For demand response events that affect central air conditioners controlled by a wi-fi connected thermostat: a deemed energy savings of 0.60 kWh[4] per event.

For Residential Storage Daily Dispatch, energy savings are measured directly at the device, on a site-by-site basis, as reported by the vendor:

$$\Delta kW_{Event} = \Delta kW_{vendor}$$

More detailed savings algorithms for Residential Storage Daily Dispatch and other types of residential active demand response measures, with pre-, during-, and post-event savings adjustments, may be developed as additional program evaluations are conducted.

Measure Life:

As all residential active demand response measures are based on Program Administrators calling demand reduction events each year, the deemed measure life is 1 year.[5]

BC Measure ID	Measure Name	Program	Measure Life

E21A5a001	Residential Direct Load Control	Residential ADR	1
E21A5a002	Residential Storage Daily Dispatch P4P (savings) Summer	Residential ADR	1
E21A5a003	Residential Storage Daily Dispatch P4P (consumption) Summer	Residential ADR	1

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A5a001	Residential Direct Load Control	Residential ADR	1.00	1.00	1.00	1.00	1.00	1.00	0.00
E21A5a002	Residential Storage Daily Dispatch P4P (savings) Summer	Residential ADR	1.00	1.00	1.00	1.00	1.00	1.00	0.00
E21A5a003	Residential Storage Daily Dispatch P4P (consumption) Summer	Residential ADR	1.00	1.00	1.00	1.00	1.00	1.00	0.00

In-Service Rates:

All installations are assumed to have 100% in-service-rates pending program evaluation. Event opt-outs and attrition during events are captured in the gross impact algorithm above.

Realization Rates:

Savings adjustment factors and deemed energy savings provided in the Algorithms section above represent an evaluation adjustment to vendor-reported reported gross savings.

Coincidence Factors:

Summer coincidence factors are assumed to be 100% reflecting the timing of demand response events. Winter coincidence factors are assumed to be 0%.

Scaling Factors:

A scaling factor is used to account for the fact that the benefits of an active demand response resource depend on how often it performs. The greater the frequency of demand response events, the more that the active demand resource reduces the installed capacity requirement, and therefore the greater its value. For planning the utilities use a scaling factor of 10% for direct load control and 100% for storage, reflecting the AESC 2018 review of sensitivity analyses run by PJM load forecasters. For reporting utilities will use scaling factor values based on the most recent evaluation timing of events that are called in 2021.

Energy Load Shape:

All savings for Active Demand Response take place in the summer on-peak period.

Endnotes:
1: ISO New England (2014). ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources (Manual M-MVDR). Revision 6, June 1, 2014 https://www.iso-ne.com/static-assets/documents/2017/02/mmvdr_measurement-and-verification-demand-reduction_rev6_20140601.pdf

2: Day-Ahead and Real-Time Market Operations (2019). PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 108. Effective Date: December 3, 2019. https://www.pjm.com/~/media/documents/manuals/m11.ashx

3: Navigant Consulting (2020). 2019 Residential Energy Storage Demand Response Demonstration Evaluation, Summer Season. Prepared for National Grid and Unitil. MA. http://ma-eeac.org/wordpress/wp-content/uploads/MA19DR02-E-Storage_Res-Storage-Summer-Eval_wInfographic_2020-02-10-final.pdf

4: Navigant Consulting (2020). 2019 Residential Wi-Fi Thermostat Direct Load Control Offering Evaluation. Prepared for Eversource, National Grid, and Unitil. MA and CT. https://ma-eeac.org/wp-content/uploads/2019-Residential-Wi-Fi-Thermostat-DLC-Evaluation-Report-2020-04-01-with-Infographic.pdf

5: The PA program evaluation plan and the measure life for behavioural measures are as published in the 2019-2021 Massachusetts Three-Year Energy Efficiency Plan. https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf

Revision History

Revision Number	Date	Description
7	1/14/2022	The deemed savings number for thermostat ADR's was updated to 0.60 kwh from 0.67 kwh.
8	1/14/2022	Fixed broken links in references

1.1 Appliances - Advanced Power Strip

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Appliances

Description:

Advanced power strips can automatically eliminate standby power loads of electronic peripheral devices that are not needed (DVD player, computer printer, scanner, etc.) either automatically or when an electronic control device (typically a television or personal computer) is in standby or off mode.

Baseline Efficiency:

The baseline efficiency case is the customers' electronic peripheral devices as they are currently operating.

High Efficiency:

The high efficiency case is the installation of an Advanced Power Strip.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on refenced study results.[1]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b001	Advanced Power Strip, Tier I	ES Products	117.00	0.011
E21A3b002	Advanced Power Strip, Tier II	ES Products	174.00	0.018

Measure Life:

The measure life is 5 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b001	Advanced Power Strip, Tier I	ES Products	0.86	0.92	n/a	0.92	0.92	0.58	0.86
E21A3b002	Advanced Power Strip, Tier II	ES Products	0.75	0.92	n/a	0.92	0.92	0.58	0.86

<u>In-Service Rates:</u>

In-service rates are based on consumer surveys, as found in the referenced study.[1]

<u>Realization Rates:</u>

Realization rates account for the savings lost due to improper customer set-up/use of devices, as found in the referenced study.[1]

<u>Coincidence Factors:</u>

Programs use a summer coincidence factor of 58% and a winter coincidence factor of 86%.[2]

Energy Load Shape:

See Appendix 1 – "Primary TV and Peripherals".[2]

<u>Endnotes</u>:
1: NMR Group, Inc. (2018). Advanced Power Strip Metering Study. Prepared for Massachusetts Program Administrators and EEAC.
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

<u>Revision History</u>

Revision Number	Date	Description
9	1/14/2022	Fixed broken links in references

1.2 Appliances – Clothes Dryer

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Appliances

Description:

Clothes dryers exceeding minimum qualifying efficiency standards established as ENERGY STAR® or most efficient.

Baseline Efficiency:

For lost opportunity applications, the baseline efficiency case is a new electric resistance dryer that meets the federal standard as of January 1, 2015 which is a Combined Energy Factor (EF) of 3.73 for a vented standard dryer[1]. Different testing procedures were used in setting the federal standard (DOE Test Procedure Appendix D1) and the Energy Star standard (DOE Test Procedure Appendix D2). To enable comparison a baseline CEF of 3.11 is used. This was derived from ENERGY STAR Version 1.0 Estimated Baseline which multiplies the 2015 federal standard by the average change in electric dryers' assessed CEF between Appendix D1 and Appendix D2: 3.73-(3.73*0.166).
For retrofit applications, the baseline efficiency case is the existing electric resistance dryer.

High Efficiency:

The high efficiency case is a clothes dryer that meets the ENERGY STAR standard as of May 19, 2014. For a new standard vented or ventless electric resistance dryer the minimum CEF is 3.93[2].
For Heat Pump and Hybrid technology clothes dryers, CEFs are based on an average of Northwest Energy Efficiency Alliance qualified product testing as of October 2019. For Heat Pump technology dyers, the average CEF is 6.83. For Hybrid technology clothes dryers, the average CEF is 4.30.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on EPA ENERGY STAR list and Northwest Energy Efficiency Alliance lab testing results. Demand savings are derived from the Navigant Demand Impact Model.[6]

$\Delta kWh = (lbs/YEAR \div CEF_{Base}) - (lbs/YEAR \div CEF_{EFF})$

Where:
Lbs/YEAR = Typical pounds of clothing dried per year (based on 8.45 lbs/load and 283 loads/yr)
CEF_{BASE} = Baseline Combined Energy Factor (lbs/kWh)
CEF_{EFF} = Efficient Combined Energy Factor (lbs/kWh)

Unit savings [3,4,5]

BC Measure Id	Measure Name	Program	ΔkWh	ΔkW	ΔGas MMBtu
E21B1a052	Clothes Dryer (Retrofit)	HEA	160.00	0.05	n/a
E21A2a055	Clothes Dryer (Retrofit)	HPwES	160.00	0.05	n/a
E21A1a027	Clothes Dryer (New Construction)	ES Homes	160.4	0.047	n/a
E21A3b010	Clothes Dryer (ENERGY STAR)	ES Products	160.4	0.047	n/a
E21A3b012	Clothes Dryer (ENERGY STAR + Hybrid technology)	ES Products	213.3	0.063	n/a
E21A3b011	Clothes Dryer (ENERGY STAR + Heat Pump technology)	ES Products	421.1	0.124	n/a

Measure Life:

The measure life is 12 years.[6]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a052	Clothes Dryer (Retrofit)	HEA	1.00	0.91	n/a	0.91	0.91	0.45	0.58
E21A2a055	Clothes Dryer (Retrofit)	HPwES	0.99	0.96	n/a	0.96	.96	0.45	0.58
E21A1a027	Clothes Dryer (New Construction)	ES Homes	1.00	1.00	n/a	1.00	1.00	0.45	0.58
E21A3b010	Clothes Dryer (ENERGY STAR + Hybrid technology)	ES Products	1.00	1.00	n/a	1.00	1.00	0.45	0.58
E21A3b012	Clothes Dryer (ENERGY STAR + Heat Pump technology)	ES Products	1.00	1.00	n/a	1.00	1.00	0.45	0.58

In-Service Rates:

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA[8], and 99% for HPwES[7].

Realization Rates:

Realization rates are 100% for ES Products unless an evaluation finds otherwise, 91% for HEA[8], and 96% for HPwES[7].

Coincidence Factors:

Programs a summer coincidence factor of 45% and a winter coincidence factor of 58%.[9]

Energy Load Shape:

See Appendix 1 – "Clothes Dryer – Electric". [9]

Endnotes:
1: DOE (accessed July 2020). Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers. https://www.energy.gov/sites/prod/files/2015/03/f20/Clothes%20Dryer%20Standards_RFI.pdf
2: EnergyStar Energy Efficient Products (accessed July 2020): https://www.energystar.gov/products/appliances/clothes_dryers/key_product_criteria
3: Northwest Energy Efficiency Alliance (2019). Dryers - QPL October 2019.
4: Department of Energy (2015). 10 CFR Part 431 March 27, 2015. Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers. Table II.7.
5: Department of Energy (2013). 10 CFR Parts 429 and 430 August 14, 2013. Energy Conservation Program: Test Procedures for Residential Clothes Dryers; Final Rule. Table 11.1.
6: Environmental Protection Agency (2018). Savings Calculator for ENERGY STAR Qualified Appliances. Energy_Star_2018_Consumer_Appliance_Calculator
7: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL, https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NHSaves-HPwES-Evaluation-Report-Final-20200611.pdf
8: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
9: Navigant Consulting, 2018. RES1 Demand Impact Model Update. https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Log

Revision Number	Date	Description
10	1/14/2022	Added savings values for retrofit clothes dryers. Previously were vendor calculated.

1.3 Appliances – Clothes Washer

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Appliances

Description:

Clothes washers exceeding minimum qualifying efficiency standards established as ENERGY STAR® or Most Efficient. The measure saves electric energy used by the washer itself, as well as heating energy (in the form of electricity or fossil fuel) associated with the heating of the domestic hot water (DHW) consumed during the wash cycles. DHW heating efficiency is assumed to be code-compliant.

Baseline Efficiency:

For lost opportunity baseline, the base efficiency case is a residential clothes washer that meets the federal standard for front-loading washers effective 3/7/2015 which requires an IMEF (Integrated Modified Energy Factor) no less than 1.84 and an IWF (Integrated Water Factor) no greater than 4.7, and for top-loading washers effective 1/1/18 which requires an IMEF no less than 1.57 and an IWF no greater than 6.5. For retrofit baseline, the base efficiency case is the existing residential clothes washer.

High Efficiency:

The high efficiency case is a residential clothes washer that meets the ENERGY STAR standard as of February 5, 2018. For a new front-loading clothes washer the minimum IMEF is 2.76 and the maximum IWF is 3.2. For a new top-loading clothes washer the minimum IMEF is 2.06 and the maximum IWF is 4.3.

Algorithms for Calculating Primary Energy Impact:

Retrofit savings can be calculated using the Energy Star Appliance Calculator, available on the Energy Star website. All other unit electric savings are based on weighted averages by efficiency class presented in the 2018 Efficiency Vermont TRM[1]. Demand savings are derived from the Navigant Demand Impact Model[5]. Fossil fuel DHW savings are based on NH-specific water heating fuel types.

Measure ID	**Measure Name**	**Program**	**ΔkWh**	**ΔkW**	**ΔGas MMBtu**	**ΔOil MMBtu**	**ΔPropane MMBtu**
E21B1a051	Clothes Washer (Retrofit)	HEA	Calculated	Calculated	Calculated	Calculated	Calculated
E21A2a054	Clothes Washer (Retrofit)	HPwES	Calculated	Calculated	Calculated	Calculated	Calculated

E21A1a026	Clothes Washer (New Construction)	ES Homes	89.9	0.279	0.000	0.000	0.050
G21A1a009	Clothes Washer (New Construction) – Gas	ES Homes	24.1	0.0.075	0.290	0.00	0.000
E21A3b017	Clothes Washer (ENERGY STAR)	ES Products	89.9	0.279	0.024	0.042	0.003
E21A3b018	Clothes Washer (ENERGY STAR Most Efficient)	ES Products	138.9	0.431	0.166	0.291	0.023

Measure Life:

The measure life is 11 years.[1, 2]

Other Resource Impacts:

Annual water savings are deemed.

Measure Name	Program	Annual Water Savings (gallons)
Clothes Washer (Retrofit)	HEA/HPwES	Calculated
Clothes Washer (New Construction)	ES Homes	2,244
Clothes Washer (ENERGY STAR)	ES Products	2,244
Clothes Washer (ENERGY STAR Most Efficient)	ES Products	3,940

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a051	Clothes Washer (Retrofit)	HEA	1.00	0.91	0.91	0.91	0.91	0.49	0.52
E21A2a054	Clothes Washer (Retrofit)	HPwES	0.99	0.96	0.96	0.96	0.96	0.49	0.52
E21A1a026	Clothes Washer (New Construction)	ES Homes	1.00	1.00	1.00	1.00	1.00	0.49	0.52
G21A1a009	Clothes Washer (New Construction) – Gas	ES Homes	1.00	1.00	1.00	1.00	1.00	0.49	0.52
E21A3b017	Clothes Washer (ENERGY STAR)	ES Products	1.00	1.00	1.00	1.00	1.00	0.49	0.52
E21A3b018	Clothes Washer (ENERGY STAR Most Efficient)	ES Products	1.00	1.00	1.00	1.00	1.00	0.49	0.52

In-Service Rates:

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA[4], and 99% for HPwES[3].

Realization Rates:

Realization rates are 100% for ES Products unless an evaluation finds otherwise, 91% for HEA[4], and 96% for HPwES[3].

Coincidence Factors:

All electric programs use a summer coincidence factor of 49% and a winter coincidence factor of 52%.[5]

Energy Load Shape:

See Appendix 1 – "Clothes Washer".[5]

Endnotes:
1: Energy Efficiency Vermont (2018) Technical Reference User Manual. Efficient Clothes Washers.
2: Appliance Magazine. U.S. Appliance Industry: Market Share, Life Expectancy & Replacement Market, and Saturation Levels. Jan. 2010. p. 10

3: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
5: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision History

Revision Number	Date	Description
11	1/14/2022	Added option to use EPA calculator for retrofit savings values. were vendor calculated.

1.4 Appliances – Dehumidifier

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Appliances

Description:

Dehumidifiers exceeding minimum qualifying efficiency standards established as ENERGY STAR.

Baseline Efficiency:

The lost opportunity baseline efficiency case is a dehumidifier that meets the federal standard effective June 13, 2019. Specific baseline Energy Factors (EFs) by product capacity found in the Code of Federal Regulations, 10 CFR 430.32(v)(2). The retrofit baseline efficiency case is the existing dehumidifier.

High Efficiency:

The high efficiency case is a dehumidifier that meets the ENERGY STAR standard as of October 31, 2019[1]. For a new dehumidifier with a capacity less than 25 pints/day the minimum EF is 1.57 liters/kWh. For a new dehumidifier with a capacity between 25.01 and 50 pints/day the minimum EF is 1.8 liters/kWh. For a new dehumidifier with a capacity greater than or equal to 50 pints/day the minimum EF is 3.3 liters/kWh.

Capacity (pints)	Energy Factor (2019 Federal Standard)	Energy Factor (ENERGY STAR)
≤ 25	1.30	1.57
25.01-50	1.60	1.80
≥ 50	2.80	3.30

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated as below. Demand savings are derived from the Navigant Demand Impact Model.[1]

$$\Delta kWh = Load \times [(1 \div Eff_{BASE}) - (1 \div Eff_{ES})] \times Hours$$

Where:
Load = Typical dehumidification load, 1520 Liters/year[1]
Eff_{BASE} = Average efficiency of model meeting the federal standard, in Liters/kWh
Eff_{ES} = Efficiency of ENERGY STAR® model, in Liters/kWh
Hours = Dehumidifier annual operating hours, site-specific if available, or deemed 2,851 hour/year[2]

Table: Measure Energy Impact[3]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21B1a053	Dehumidifier (Retrofit)	HEA	407.1	0.10
E21A2a056	Dehumidifier (Retrofit)	HPwES	407.1	0.10
E21A3b019	Dehumidifier (ENERGY STAR)	Products	82.3	0.02

Measure Life:

The measure life is 12 years.[3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a053	Dehumidifier (Retrofit)	HEA	1.00	0.91	n/a	0.91	0.91	0.82	0.17
E21A2a056	Dehumidifier (Retrofit)	HPwES	0.99	0.96	n/a	0.96	0.96	0.82	0.17
E21A3b019	Dehumidifier (ENERGY STAR)	ES Products	1.00	1.00	n/a	1.00	1.00	0.82	0.17

In-Service Rates:

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA[5], and 99% for HPwES[4].

Realization Rates:

Realization rates are 100% for ES Products unless an evaluation finds otherwise, 91% for HEA[5], and 96% for HPwES[4].

Coincidence Factors:

All programs use a summer coincidence factor of 82% and a winter coincidence factor of 17%.[1]

Energy Load Shape:

See Appendix 1 – “Dehumidifier”.[1]

Endnotes:
1: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

2: Environmental Protection Agency (2019). Dehumidifier Key Efficiency Criteria.
https://www.energystar.gov/products/appliances/dehumidifiers/key_efficiency_criteria
3: Environmental Protection Agency (2014). Savings Calculator for Energy Star Qualified Appliances. ENERGY_STAR_2015_Appliance_Calculator
4: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
5: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

1.5 Appliances – Dishwasher

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Appliances

Description:

The installation of a high efficiency ENERGY STAR residential dishwasher.

Baseline Efficiency:

The baseline efficiency case is a dishwasher that meets the federal standard effective May 30, 2013. Standard size dishwashers shall not exceed 307 kwh/year and 5.0 gallons per cycle.

High Efficiency:

The high efficiency case is a dishwasher that meets the ENERGY STAR standard as of January 29, 2016. Standard size dishwashers shall not exceed 270 kwh/year and 3.5 gallons per cycle.

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated based on the EPA ENERGY STAR appliance calculator. Demand savings are derived from the Navigant Demand Impact Model.

$\Delta kWh = kWh_{BASE} - kWh_{ES}$

Where:
kWh_{BASE} = Average usage of a baseline dishwasher
kWh_{ES} = Average usage of a new dishwasher meeting ENERGY STAR® standards

Table: Measure Energy Impact[1]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b020	ES Dishwasher	ES Products	37.0	0.011

Measure Life:

The measure life is 10 years.[1]

Other Resource Impacts:

There are annual water savings of 161 gallons associated with this measure.[1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b020	ES Dishwasher	ES Products	1.00	1.00	n/a	1.00	1.00	0.28	0.48

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Programs use a summer coincidence factor of 28% and a winter coincidence factor of 48%.[2]

Energy Load Shape:

See Appendix 1 – "Dishwasher".[2]

Endnotes:
1: Environmental Protection Agency (2018). Savings Calculator for Energy Star Qualified Appliances.
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

1.6 Appliances – Freezer

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Appliances

Description:

Freezers exceeding minimum qualifying efficiency standards established as ENERGY STAR®.

Baseline Efficiency:

For lost-opportunity, the baseline efficiency case is a freezer that meets the Federal standard effective September 15, 2014. Specific baseline coefficients and constants by product class found in the Code of Federal Regulations, 10 CFR 430.32(a). For retrofit, the baseline efficiency case is the existing freezer.

High Efficiency:

The high efficiency case is a freezer that meets the ENERGY STAR standard as of September 15, 2014. For a new freezer the measured energy use must be 10% less than the minimum federal efficiency standards.

Algorithms for Calculating Primary Energy Impact:

Retrofit unit energy and demand savings are based on project-specific calculations. Lost-opportunity unit energy and demand savings are based on calculations from the 2018 Vermont TRM[2].

$\Delta kWh = kWh_{BASE} - kWh_{ES}$

Where:
kWh_{BASE} = Average usage of a baseline freezer
kWh_{ES} = Average usage of a new freezer meeting ENERGY STAR® standards

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21B1a050	Freezer (Retrofit)	HEA	Calculated	Calculated
E21A2a053	Freezer (Retrofit)	HPwES	Calculated	Calculated
E21A3b021	Freezer (ENERGY STAR®)	ES Products	31.2	0.004

Measure Life:

The measure life is 12 years.[6]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a050	Freezer (Retrofit)	HEA	1.00	0.91	n/a	0.91	0.91	0.91	0.68
E21A2a053	Freezer (Retrofit)	HPwES	0.99	0.96	n/a	0.96	0.96	0.91	0.68
E21A3b021	Freezer (ENERGY STAR®)	ES Products	1.00	1.00	n/a	1.00	1.00	0.91	0.68

In-Service Rates:

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA[4], and 99% for HPwES[3].

Realization Rates:

Realization rates are 100% for ES Products unless an evaluation finds otherwise, 91% for HEA[4], and 96% for HPwES[3].

Coincidence Factors:

Summer and winter coincidence factors are estimated using the demand allocation methodology described in the referenced study.[5]

Energy Load Shape:

See Appendix 1 – "Freezer".[5]

Endnotes:
2: Vermont TRM (2018): ENERGY STAR Retail Products Platform, page 178 of 313.
3: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
5: Navigant Consulting,2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
6: Environmental Protection Agency (2018). Savings Calculator for Energy Star Qualified Appliances.

1.7 Appliances – Refrigerator

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Appliances

Description:

Refrigerators exceeding minimum qualifying efficiency standards established as ENERGY STAR®.

Baseline Efficiency:

The new product baseline efficiency case is a refrigerator that meets the Federal standard effective September 15, 2014. Specific baseline coefficients and constants by product class found in the Code of Federal Regulations, 10 CFR 430.32(a).

The retrofit baseline efficiency case is an existing refrigerator. It is assumed that income eligible customers would otherwise replace their refrigerators with a used inefficient unit.

High Efficiency:

The high efficiency case is a refrigerator that meets the ENERGY STAR standard as of September 15, 2014. For a new refrigerator the measured energy use must be 10% less than the minimum federal efficiency standards.

Algorithms for Calculating Primary Energy Impact:

Unit energy savings are based on consumption values from New Hampshire evaluation results.[1] Demand savings are derived from the Navigant Demand Impact Model[2].

$\Delta kWh = (kWh_{BASE} - kWh_{ES}) \times SLF$

Where:
kWh_{BASE} = Average baseline usage: a new refrigerator meeting federal standards, average energy consumption assumed to be 502 kWh for lost-opportunity, site-specific for retrofit
kWh_{ES} = Average usage of a new refrigerator meeting ENERGY STAR® standards with an average energy consumption of 452 kWh for ENERGY STAR refrigerators, or 393 kWh for Most Efficient refrigerator
SLF = Site/Lab adjustment factor (an adjustment for real-world performance (site) versus testing (lab)) = 0.881[3]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21B1a049	Refrigerator (Retrofit)	HEA	Calculated	Calculated
E21A2a049	Refrigerator (Retrofit)	HPwES	Calculated	Calculated

E21A1a025	Refrigerator (New Construction)	ES Homes	44.2	0.01
E21A3b022	Refrigerator (ENERGY STAR®)	ES Products	44.2	0.01
E21A3b023	Refrigerator (Most Efficient)	ES Products	96.4	0.02

Measure Life:

The measure life is 12 years.[4]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a049	Refrigerator (Retrofit)	HEA	1.00	0.91	n/a	.91	0.91	0.79	0.65
E21A2a049	Refrigerator (Retrofit)	HPwES	0.99	0.96	n/a	0.96	0.96	0.79	0.65
E21A1a025	Refrigerator (New Construction)	ES Homes	1.00	1.00	n/a	1.00	1.00	0.79	0.65
E21A3b022	Refrigerator (ENERGY STAR®)	ES Products	1.00	1.00	n/a	1.00	1.00	0.79	0.65
E21A3b023	Refrigerator (Most Efficient)	ES Products	1.00	1.00	n/a	1.00	1.00	0.79	0.65

<u>In-Service Rates:</u>

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA[5], and 99% for HPwES[1].

<u>Realization Rates:</u>

Realization rates are 100% for ES Products unless an evaluation finds otherwise, 91% for HEA[5], and 96% for HPwES[1].

<u>Coincidence Factors:</u>

A summer coincidence factor of 79% and a winter coincidence factor of 65% are based on the Navigant Demand Impact Model.[2]

Energy Load Shape:

See Appendix 1 – "Primary Refrigerator".[2]

Endnotes:

1: Opinion Dynamics (2019). Home Performance with Energy Star Program Evaluation Report 2016-2017. Prepared for NH Utilities. ES standard energy consumption values and savings methodology extracted from supporting analysis.
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org /wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf.
3: Connecticut Program Savings Document (PSD) (2019).
4: Environmental Protection Agency (2018). Savings Calculator for Energy Star Qualified Appliances.
5: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

1.8 Appliances – Recycling

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit
Category	Appliances

Description:

The retirement of old, inefficient refrigerators, freezers and room air conditioners. In cases when these appliances are replaced by a homeowner, the existing unit is retained, sold or donated for use elsewhere, representing additional load on the grid. This measure covers recycling of the existing, functional equipment, thereby eliminating the consumption associated with that equipment. Appliance recycling programs receive energy savings credit for permanently removing inefficient, functional equipment from the electric grid.

Baseline Efficiency:

The baseline efficiency case is an old, inefficient working refrigerator, freezer or room air conditioner.

High Efficiency:

The high efficiency case assumes no replacement of the recycled unit.

Algorithms for Calculating Primary Energy Impact:

Unit energy and demand savings are deemed based on MA study results.[1, 2]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b027 E21A3b028	Refrigerator Recycling	ES Products	1,027	0.18
E21A3b029	Freezer Recycling	ES Products	769	0.14
E21A3b030	Room Air Conditioner Recycling	ES Products	113	0.18

Measure Life:

The measure life is 5 years for refrigerators, 4 years for freezers and 3 years for room air conditioners.[3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings[2]:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b027	Refrigerator Recycling	ES Products	1.00	1.00	n/a	1.00	1.00	0.79	0.65
E21A3b028	Secondary Refrigerator Recycling	ES Products	1.00	1.00	n/a	1.00	1.00	0.86	0.52
E21A3b029	Freezer Recycling	ES Products	1.00	1.00	n/a	1.00	1.00	0.91	0.68
E21A3b030	Room Air Conditioner Recycling	ES Products	1.00	1.00	n/a	1.00	1.00	0.46	0.00

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are based on the Navigant Demand Impact Model.[2]

Energy Load Shape:

See Appendix 1 – "Primary Refrigerator" for primary refrigerator recycling, "Secondary Refrigerator" for secondary refrigerator recycling, "Freezer" for secondary freezer recycling, "Room or Window Air Conditioner" for room air conditioner recycling.[2]

Endnotes:

1: NMR Group, Inc. (2019). Appliance Recycling Report. Prepared for MA Joint Utilities. https://ma-eeac.org/wp-content/uploads/MA19R01-E-ApplianceRecycleReport-Final-2019.03.26.pdf

2: Room air conditioning recycling savings are based on the early replacement savings value found in The Cadmus Group, Inc. (2015). Massachusetts Low-Income Multifamily Initiative Impact Evaluation. http://ma-eeac.org/wp-content/uploads/Low-Income-Multifamily-Impact-Evaluation4.pdf

3: California Public Utilities Commission, 2014 Database for Energy-Efficient Resources, Feb. 4, 2014. Available at: http://www.deeresources.com/files/DEER2013codeUpdate/download/DEER2014-EUL-table-update_2014-02-05.xlsx

4: Navigant Consulting, 2018. RES1 Demand Impact Model Update https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

1.9 Appliances – Room Air Purifier

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Appliances

Description:

Room air purifiers exceeding minimum qualifying efficiency standards established as ENERGY STAR®.

Baseline Efficiency:

The baseline efficiency case is a room air purifier that does not meet ENERGY STAR® efficiency requirements.

High Efficiency:

The high efficiency case is a room air purifier that meets the ENERGY STAR® standard as of July 1, 2004. A new room air purifier must produce a minimum Clean Air Delivery Rate (CADR)[1] of 50, and minimum performance of 3.0 CADR per watt.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on averaged inputs from the EPA EnergyStar calculator.[2]

Measure Name	kWh	kW
Room Air Cleaner	391	0.04

Demand savings are calculated using the following formula:

$$\Delta kW = \frac{\Delta kWh}{Hours}$$

Where:
$Hours$ = Assumed annual operating hours, 8,760 hours per year

Measure Life:

The measure life is 9 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b025	Room Air Purifier	ES Products	0.97	1.00	n/a	1.00	1.00	1.00	1.00

In-Service Rates:

In-service rate is based on evaluation results.[3]

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are 100% for both summer and winter peaks, since the air purifiers are expected to operate continuously during peak hours.

Energy Load Shape:

See Appendix 1 – "24 hour operation".[4]

Endnotes:
1: The Clean Air Delivery Rate is voluntary standard made available for comparing the performance of portable air filters in a room at steady-state conditions during a controlled laboratory test: ANSI/AHAM AC-1-2015 (AHAM 2015). It was developed by the Association of Home Appliance Manufacturers (AHAM), a private voluntary standard-setting trade association, and is recognized by the American National Standards Institute (ANSI).
2: Energy Star (2018). Savings Calculator for Energy Star Appliances. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4886e6996f260b17df793/view?authToken=76a386554f80c635695670ab6c5f42d3a2689e84fed3c5c17ba875a72d1de97d358af4b53cf387bb4d6fe50367f9f9a7099bca84678c31644b474ab83eb99be06c5e49983ae488
https://www.energystar.gov/sites/default/files/asset/document/appliance_calculator.xlsx
3: NMR Group, Inc. (2018). Products Impact Evaluation of In-Service and Short Term Retention Rates Study.
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org /wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf.

1.10 Motors- ECM Circulator Pump

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Motors and Drives

Description:

Installation of high efficiency residential boiler circulator pumps, equipped with variable speed electronically commutated motors (ECMs).

Baseline Efficiency:

The baseline efficiency case is the installation of a standard circulator pump.

High Efficiency:

The high efficiency case is the installation of an ECM circulator pump.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results[1].

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b013	ECM Motor for FWH Circulating Pump	ES Products	68.0	0.024

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b013	ECM Motor for FWH Circulating Pump	ES Products	1.00	1.00	n/a	1.00	1.00	0.00	1.00

<u>In-Service Rates:</u>

All installations have a 100% in-service-rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Programs use a summer coincidence factor of 0% and a winter coincidence factor of 100%, because the deemed value of 0.024 kW cited above represents coincident winter peak demand reduction .[1]

Energy Load Shape:

See Appendix 1 – "Boiler Distribution".[2]

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

For ECM motors delivered through midstream channels, the following factors apply.

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21A3b013	ECM Motor for FWH Circulating Pump	ES Products	0.40	0.09	0.00	0.69

Endnotes:
1: West Hill Energy and Computing, 2018. CT HVAC and Water Heater Process and Impact Evaluation and CT Heat Pump Water Heater Impact Evaluation.
2: Assumed to be consistent with C&I Electric Motors & Drives – Energy & Resources Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities; Table 1-1. ERS_2005_Measure_Life_Study

1.11 Motors - Pool Pump

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Motors and Drives

Description:

The installation of a variable-speed drive pool pump. Operating a pool pump for a longer period at a lower wattage can move the same amount of water, using significantly less energy.

Baseline Efficiency:

The baseline efficiency case is a single speed 1.5 horsepower pump that pumps 97 gallons per minute (gpm) and runs 5.7 hours per day for 122 days a year. It has an Energy Factor (EF) of 2.0 . The pool size is assumed to be 22,000 gallons.[1]

High Efficiency:

The high efficiency case is a variable-speed pump rated at 77 gpm at high speed and 31 gpm at low speed. It has a 2.9 EF at high speed, a 10.5 EF at low speed and runs 2 hr/day at high speed for filter and cleaning and 15.7 hr/ day for filtering alone. The pool size is assumed to be 22,000 gallons. [1]

Algorithms for Calculating Primary Energy Impact[1]:

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b024	Pool Pump (Variable Speed)	ES Products	1,284	1.35

Measure Life:

The measure life is 10 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b024	Pool Pump (Variable Speed)	ES Products	1.00	1.00	n/a	1.00	1.00	0.55	0.00

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Programs use a summer coincidence factor of 55% and a winter coincidence factor of 0% which are estimated using demand allocation methodology described in the Demand Impact Model.[3]

Energy Load Shape:

See Appendix 1 – "Pool Pump".[3]

Endnotes:

1. DOE, December 2016. Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment; Dedicated – Purpose Pool Pumps. https://www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105

2. Davis_Energy_Group_2008_Proposal_Info_Template_for_Residential_Pool_Pump_Measure_Revisions https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4886d6996f219ce7df78e/view?authToken=3b71e1346320906c2aa98b46f0bc51366572ba635fb746acadde94699187bcb6ff5af967900e9bb3a8ba4ef6c9998da9c7213c8b2be31b4420695f20c39232a5c3f169b40bb1c9

3: Navigant, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

1.12 Building Shell – Air Sealing

Measure Code	[To Be Defined in ANB system],
Market	Residential
Program Type	Retrofit, Single Family
Category	Building Shell

Description:

The reduction of a home's conditioned air loss (leakage) resulting from the sealing of a home's cracks and air gaps. Home air leakage is measured in air loss in Cubic Feet per Minute (CFM), measured at 50 pascals.

Baseline Efficiency:

The baseline efficiency case is an existing home before it is air sealed.

High Efficiency:

The high efficiency case is an existing home after it has been air sealed.

Algorithms for Calculating Primary Energy Impact:

The programs use vendor-calculated energy savings for air sealing measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates building heating and cooling loads and other key parameters. The software's building model is based on thermal transfer, building gains, and a variable-based heating and cooling degree day (or hour) climate model. This provides an initial estimate of energy use that may be compared with actual billing data to adjust as needed for existing conditions. Then, specific recommendations for improvements are added and savings are calculated using measure-specific heat transfer algorithms.

Rather than using a fixed degree day approach, the building model estimates both heating degree days and cooling degree hours based on the actual characteristics and location of the house to determine the heating and cooling balance point temperatures. Infiltration savings use site-specific seasonal N-factors to convert measured leakage to seasonal energy impacts. HVAC savings are estimated based on changes in system and/or distribution efficiency improvements, using ASHRAE 152 as their basis. Interactivity between architectural and mechanical measures is always included, to avoid overestimating savings due to incorrectly "adding" individual measure results.

Should the vendor software be unavailable or unable to estimate a home's energy savings from air sealing, the following savings algorithm should be used.

$\Delta MMBtu = \Delta CFM * MMBtu/CFM$
Where:
ΔCFM = Reduced air loss, in Cubic Feet per Minute (CFM) in a treated home.

MMBtu/CFM = Deemed savings per reduced CFM of 0.012787 MMBtu per CFM. This represents a blended savings value, applicable for all heating fuel types and cooling equipment scenarios in HPwES, based on evaluation results, exclusive of ancillary heating and cooling savings.[1]

Measure Life:

The effective useful life (EUL) for air sealing, which assumes retrofit installation, is 15 years.[2]

Impact Factors for Calculating Adjusted Gross Savings:[1 4]

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a001	Air Sealing	Cord Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a001	Air Sealing	Cord Wood	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a002	Air Sealing	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.00	0.43
E21A2a002	Air Sealing	Electric	HPwES	0.99	0.96	n/a	0.96	0.96	0.00	0.43
E21B1a003 G21B1a001	Air Sealing	Gas	HEA	1.00	n/a	1.04	n/a	n/a	n/a	n/a
E21A2a003 G21A2a001	Air Sealing	Gas	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21B1a004	Air Sealing	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a004	Air Sealing	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a005	Air Sealing	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a005	Air Sealing	Oil	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a006	Air Sealing	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a006	Air Sealing	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a007	Air Sealing	Wood Pellets	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a007	Air Sealing	Wood Pellets	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a

In-Service Rates:

In-service rates for HPwES programs are 99% and are 100% HEA programs based on evaluation results[1,4].

Realization Rates:

Realization rate for HPwES programs are 96% and are 91% for HEA programs based on evaluation results. Non-electric realization rates are 114% for oil and propane fuel types and 104% for gas. [1,4]

Coincidence Factors:

For primary savings, a summer coincidence factor of 23.25% and a winter coincidence factor of 25.41% is used, based on the "Weighted Whole Home HVAC" load shape. [4]

Other Resource Impacts:

In addition to the primary heating fuel savings, the following deemed values are applied to HPwES program measures to reflect ancillary electric savings for heating and cooling load reductions, depending on the equipment used in the home. Heating ancillary savings result from both reduced furnace fan runtime, or reduced boiler pump operation due to the HVAC Load reductions resulting from weatherizing homes. [1] Ancillary cooling savings are derived from the average cooling system runtime reduction. [1] The values are based on evaluation results for weatherized homes and are applied once per home for homes receiving air sealing and/or insulation (rather than separately applying the savings for each measure. Ancillary savings would only be applied once for a house that received insulation in addition to air sealing.)

BC Measure ID	Measure Name	Measure Life[3]	Equipment	Savings/unit [1]	Description of Impact	CF_{SP}	CF_{WP} [5]
E21A2b023	HVAC Ancillary, heating	18	Furnace fan	86.00 kWh/Home	Per home value reflecting reduced fan operation based on heating load reduction from weatherization measures	0.00	0.46
E21A2b022	HVAC Ancillary, heating	19	HW boiler circulation pump(s)	9.00 kWh/Home	Per circulator pump value reflecting reduced pump operation based on heating load reduction from weatherization measures	0.00	0.45
E21A2b024	HVAC Ancillary, cooling.	18	Central HVAC - Cooling system fan, blower door test completed	4.28 kWh/ 100 CFM	Per CFM savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.47

E21A2b024	HVAC Ancillary , cooling	18	Central HVAC - Cooling system fan, blower door test not completed.	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.47
E21A2b025	HVAC Ancillary , cooling.	18	Room/Window AC - Cooling system fan, blower door test completed	4.28 kWh/ 100 CFM	Per CFM savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.48
E21A2b025	HVAC Ancillary , cooling	18	Room/Window AC - Cooling system fan, blower door test not completed	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.48
E21A2b026	HVAC Ancillary , cooling.	18	Mini- Split AC/ HP - Cooling system fan, blower door test completed	4.28 kWh/ 100 CFM	Per CFM savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.43
E21A2b026	HVAC Ancillary , cooling	18	Mini- Split AC/ HP - Cooling system fan, blower door test not completed.	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.43

*Ancillary heating savings are applicable when air sealing and/or envelope insulation measures are implemented in a home and are dependent on the heating system distribution motor (furnace fan or boiler pump). Savings are only applicable once per home. [1]
**Ancillary cooling savings are applicable when air sealing and/or envelope insulation measures are implemented in a home with cooling. When air sealing is completed in a home and CFM reductions are verified through a blower door test, use the 0.0146 MMBtu/100 CFM reduction savings value. When a blower door is not completed, or only envelop insulation measures are implemented, apply the 0.178 MMBtu/Home savings value. Savings are only applicable once per home. [1]

Energy Load Shape:

For air sealing, see Appendix 1. – "Weighted Whole Home HVAC"
For ancillary heating savings in a home with a furnace, see Appendix 1 – "Furnace Fan"
For ancillary heating savings in a home with a boiler, see Appendix 1 – "Boiler distributor"
For ancillary cooling savings in a home with central or a heat pump, see Appendix 1 "Central Air Conditioner/ Heat pump (cooling)".
For ancillary cooling savings in a home with room or window AC, see Appendix 1 – "Room or Window Air Conditioner"
For ancillary cooling savings in a home with a mini-split AC or heat pump, see Appendix 1 – "Mini-split AC/ Heat Pump (Cooling)".

Non-Energy Impacts:

For HEA programs, a per-project value of $406 reflecting participant NEIs—including increased comfort, decreased noise, and health-related NEIs—will be applied annually to each weatherization project over its 15-year measure life[4].

Endnotes:
1: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL. https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NHSaves-HPwES-Evaluation-Report-Final-20200611.pdf
2: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007. https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
3: Measure life of ancillary savings for each equipment type, corresponds to the measure life cited in the corresponding TRM chapter. For example, the HVAC ancillary measure savings for a furnace fan correspond the measure life of a Furnace in the Residential – HVAC- furnaces Chapter.
4: Opinion Dynamics. Home Energy Assistance Program Evaluation Report 2016-2017, Final, July 29, 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf
5: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	Issue Date	Description
12	1/14/2022	Updated to reference the “Weighted Whole Home HVAC” load shape for air sealing, rather than the hardwired electric heat load shape.
13	1/14/2022	Added ancillary heating and cooling savings and separate BC measure ID’s
14	1/14/2022	Updated the air sealing load shape to “Weighted Whole Home HVAC”, and added load shapes for ancillary savings.

1.13 Building Shell – Insulation

Measure Code	[To Be Defined in ANB system],
Market	Residential
Program Type	Retrofit
Category	Building Shell

Description:

The installation of additional insulation in an existing home.

Baseline Efficiency:

The baseline efficiency case is the pre-installation average R-value for an insulation type in an existing home before installation of new insulation.

High Efficiency:

The high efficiency case is the post-installation average R-value for an insulation type in an existing home.

Algorithms for Calculating Primary Energy Impact:

The programs currently use vendor calculated energy savings for these measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates building heating and cooling loads and other key parameters. The proprietary building model is based on thermal transfer, building gains, and a variable-based heating/cooling degree day/hour climate model. This provides an initial estimate of energy use that may be compared with actual billing data to adjust as needed for existing conditions. Then, specific recommendations for improvements are added and savings are calculated using measure-specific heat transfer algorithms.

Rather than using a fixed degree day approach, the building model estimates both heating degree days and cooling degree hours based on the actual characteristics and location of the house to determine the heating and cooling balance point temperatures. Savings from shell measures use standard U-value, area, and degree day algorithms. HVAC savings are estimated based on changes in system and/or distribution efficiency improvements, using ASHRAE 152 as their basis. Interactivity between architectural and mechanical measures is always included, to avoid overestimating savings due to incorrectly "adding" individual measure results. Should the vendor software be unavailable or unable to estimate a home's energy savings from insulation, the following savings algorithm should be used.[1]

ΔMMBtu = HSqFt * (MMBtu*heating*)

ΔkWh= (HSqFT *(MMBtu*cooling*))*293.017

Where:

HSqFt = Hundred square feet of installed insulation in a treated home (represented by installed sq ft / 100 sq ft).
MMBtu*heating* = Deemed savings per square foot of installed insulation, using appropriate value for basements, walls, or attics in the tables developed by Opinion Dynamics and program implementers.[1]
MMBtu*cooling* = If cooling is present in treated home, use appropriate value for basements, walls, or attics the table developed by Opinion Dynamics and program implementers. Otherwise set to 0.[1]
293.017 = kWh conversion factor.
In addition to heating fuel savings, the following deemed values are applied to reflect ancillary electric savings for heating load reductions, depending on the home heating equipment. The values are based on evaluation results for weatherized homes, and are applied once per home for homes receiving air sealing and/or insulation (rather than separately applying for air sealing and insulation):[1]

Measure Life:

The effective useful life (EUL) for insulation, which assumes retrofit installation, is 25 years.[3]

Impact Factors for Calculating Adjusted Gross Savings:[1,4]

BC Measure ID	Measure Name	Fuel	ISR	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a022	Insulation	Cord Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a022	Insulation	Cord Wood	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a023	Insulation	Electric	HEA	1.00	0.91	n/a	0.91	0.91	.23	.25
E21A2a023	Insulation	Electric	HPwES	0.99	0.96	n/a	0.96	0.96	0.00	0.43
E21B1a024 G21B1a004	Insulation	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a024 G21A2a004	Insulation	Gas	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21B1a025	Insulation	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a025	Insulation	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a026	Insulation	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a026	Insulation	Oil	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a027	Insulation	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a027	Insulation	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1a028	Insulation	Wood Pellets	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a028	Insulation	Wood Pellets	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a063	Duct Insulation	Cord Wood	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a064	Duct Insulation	Electric	HPwES	0.99	0.96	n/a	0.96	0.96	0.00	0.43
E21A2a065	Duct Insulation	Gas	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21A2a066	Duct Insulation	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a067	Duct Insulation	Oil	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a068	Duct Insulation	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a069	Duct Insulation	Wood Pellets	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

In-service rates are 99% for HPwES programs and are 100% HEA programs based on evaluation results.[1,4]

<u>Realization Rates:</u>

Realization rate for HEA% measures is 91%[1]. Realization rates for electric HPwES measures is 96%.Non-electric realization rates for HPwES are 114% for oil and propane fuel types and 104% for gas.[4]

Coincidence Factors:

For primary savings, a summer coincidence factor of 23.25% and a winter coincidence factor of 25.41% is used, based on the "Weighted Whole Home HVAC" load shape. [4]

Other Resource Impacts:

In addition to heating fuel savings, the following deemed values are applied to HPwES program measures to reflect ancillary electric savings for heating and cooling load reductions, depending on the equipment used in the home. The values are based on evaluation results for weatherized homes, and are applied once per home for homes receiving air sealing and/or insulation (rather than separately applying for air sealing and insulation):[1,5]

BC Measure ID	Measure Name	Measure Life[2]	Equipment	Savings/unit[1]	Description of Impact	CF_{SP}	CF_{WP} [5]
E21A2b023	HVAC Ancillary, heating	18	Furnace fan	86.00 kWh/Home	Per home value reflecting reduced fan operation based on heating load reduction from weatherization measures	0.00	0.46
E21A2b022	HVAC Ancillary, heating	19	HW boiler circulation pump(s)	9.00 kWh/Home	Per circulator pump value reflecting reduced pump operation based on heating load reduction from weatherization measures	0.00	0.45
E21A2b024	HVAC Ancillary, cooling	18	Central HVAC - Cooling system fan, blower door test not completed.	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.47

E21A2b025	HVAC Ancillary, cooling	18	Room/Window AC - Cooling system fan, blower door test completed	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.48
E21A2b026	HVAC Ancillary, cooling	18	Mini- Split AC/ HP - Cooling system fan, blower door test not completed.	52.17 kWh/Home	Per home savings value reflecting reduced average system fan runtime reduction due to air sealing.	0.00	.43

*Ancillary heating savings are applicable when air sealing and/or envelope insulation measures are implemented in a home and are dependent on the heating system distribution motor (furnace fan or boiler pump). Savings are only applicable once per home. [1]
**Ancillary cooling savings are applicable when air sealing and/or envelope insulation measures are implemented in a home. When air sealing is completed in a home and CFM reductions are verified through a blower door test, use the 0.0146 MMBtu/100 CFM reduction savings value. When a blower door is not completed, or only envelop insulation measures are implemented, apply the 0.178 MMBtu/Home savings value. Savings are only applicable once per home. [1]

Energy Load Shape:

See Appendix 1. – "Weighted Whole Home HVAC"
For air sealing, see Appendix 1. – "Weighted Whole Home HVAC"
For ancillary heating savings in a home with a furnace, see Appendix 1 – "Furnace Fan"
For ancillary heating savings in a home with a boiler, see Appendix 1 – "Boiler distributor"
For ancillary cooling savings in a home with central or a heat pump, see Appendix 1 "Central Air Conditioner/ Heat pump (cooling)".
For ancillary cooling savings in a home with room or window AC, see Appendix 1 – "Room or Window Air Conditioner"
For ancillary cooling savings in a home with a mini-split AC or heat pump, see Appendix 1 – "Mini-split AC/ Heat Pump (Cooling)".

Non-Energy Impact:

For HEA programs, a per-project value of $406 reflecting participant NEIs—including increased comfort, decreased noise, and health-related NEIs—will be applied annually to each weatherization project over its 15-year measure life.

Endnotes:
1: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL. Excel file associated with report with calculations, "2019 NHSaves HPwES Deemed Savings_2020-02-25_FM adjustments".

2: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007. https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
3: Measure life of ancillary savings for each equipment type, corresponds to the measure life cited in the corresponding TRM chapter. For example, the HVAC ancillary measure savings for a furnace fan correspond the measure life of a Furnace in the Residential – HVAC- furnaces Chapter.
4: Opinion Dynamics. Home Energy Assistance Program Evaluation Report 2016-2017, Final, July 29, 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf
5: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	**Issue Date**	**Description**
15	1/14/2022	Updated to reference the “Weighted Whole Home HVAC” load shape for air sealing, rather than the hardwired electric heat load shape.
16	1/14/2022	Added ancillary heating and cooling savings and separate BC measure ID’s
17	1/14/2022	Updated the air sealing load shape to “Weighted Whole Home HVAC”, and added load shapes for ancillary savings.
18	1/14/2022	Updated to include duct insulation measures

1.14 Building Shell – Door Replacement

Measure Code	TBD
Market	Residential
Program Type	New Construction, Retrofit
Category	Building Shell

Description:

Installation of insulated exterior doors.

Baseline Efficiency:

The baseline condition is an existing un-insulated or damaged exterior door.

High Efficiency:

The high efficiency case is an insulated exterior door.

Algorithms for Calculating Primary Energy Impact:

Savings are vendor calculated using proprietary software which takes into account the existing conditions of the home, heating and cooling degree days, and the heat loss delta.

Deemed Savings:

BC ID	Measure Name	ΔkWh	ΔkW	Δtherms
E21B1a070 E21B1a071 E21B1a072 E21B1a073 E21B1a074 E21B1a075 E21B1a076	Insulated door	Calculated	Calculated	Calculated

Measure Life:

The measure life for an efficient door is 25 years. [1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a070	Insulated Door	Cord Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a071	Insulated Door	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.23	0.25
E21B1a072	Insulated Door	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a073	Insulated Door	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a074	Insulated Door	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a075	Insulated Door	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a076	Insulated Door	Wood Pellets	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

Realization rate for HPwES programs are 96% and are 91% for HEA programs based on evaluation results. Non-electric realization rates are 114% for oil and propane fuel types and 104% for gas [2]

Coincidence Factors:

For primary savings, a summer coincidence factor of 23.25% and a winter coincidence factor of 25.41% is used, based on the “Weighted Whole Home HVAC” load shape. [3]

Other Resource Impacts:

For HEA programs, a per-project value of $406 reflecting participant NEIs—including increased comfort, decreased noise, and health-related NEIs—will be applied annually to each weatherization project over its 15-year measure life.

Energy Load Shape:

See Appendix 1. – “Weighted Whole Home HVAC”

Endnotes:

1: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007.

https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
2: Opinion Dynamics. Home Energy Assistance Program Evaluation Report 2016-2017, Final, July 29, 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf
3: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org /wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	**Issue Date**	**Description**
19	1/14/2022	Omitted measure added

1.15 Building Shell – Window Replacement

Measure Code	TBD
Market	Residential
Program Type	New Construction, Retrofit
Category	Building Shell

Description:

Replacement of single pane windows or Jalosie mobile home windows.

Baseline Efficiency:

Baseline efficiency is defined as a single pane of Jalosie mobile home window.

High Efficiency:

The high efficiency case are energy efficient double pan window replacements.

Algorithms for Calculating Primary Energy Impact:

Savings are vendor calculated using proprietary software which takes into account the existing conditions of the home, heating and cooling degree days, and the heat loss delta of the old window and new replacement window

BC ID	Measure Name	ΔkWh	ΔkW	Δtherms
E21B1a055 E21B1a064 E21B1a065 E21B1a066 E21B1a067 E21B1a068 E21B1a069	Window Replacement	Calculated	Calculated	Calculated

Measure Life:

The measure life for an efficient window is 25 years. [1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a055	Window Replacement	Cord Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a064	Window Replacement	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.23	0.25
E21B1a065	Window Replacement	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a066	Window Replacement	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a067	Window Replacement	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a068	Window Replacement	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a069	Window Replacement	Wood Pellets	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

Realization rates are 91% for HEA programs based on evaluation results. [2]

Coincidence Factors:

For primary savings, a summer coincidence factor of 23.25% and a winter coincidence factor of 25.41% is used, based on the "Weighted Whole Home HVAC" load shape. [3]

Other Resource Impacts:

For HEA programs, a per-project value of $406 reflecting participant NEIs—including increased comfort, decreased noise, and health-related NEIs—will be applied annually to each weatherization project over its 15-year measure life.

Energy Load Shape:

See Appendix 1. – "Weighted Whole Home HVAC"

Endnotes:
1: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007. https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
2: Opinion Dynamics. Home Energy Assistance Program Evaluation Report 2016-2017, Final, July 29, 2020. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf

3: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	**Issue Date**	**Description**
20	1/14/2022	Omitted measure added

1.16 Hot Water – Faucet Aerator

Measure Code	
Market	Residential
Program Type	Retrofit
Category	Hot Water

Description:

Installation of aerators meeting the EPA WaterSense specification to replace Federal Standard or higher flow faucet aerators.

Baseline Efficiency:

The baseline efficiency case is the existing faucet aerators with Federal Standard[1] flow rate of 2.2 gallons per minute (GPM) or higher.

High Efficiency:

The high efficiency case is a low flow faucet aerator with EPA WaterSense[2] specified maximum flow rate of 1.5 GPM.

Algorithms for Calculating Primary Energy Impact:

The programs use vendor calculated energy savings for measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates domestic hot water loads and other key parameters. Should the vendor software be unavailable or unable to estimate a home's energy savings from faucet aerators, the following deemed savings should be used, based on evaluation results.[3, 4]

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW[4]	ΔMMBtu
E21B1a009	Faucet Aerator	Electric	HEA	46.863	0.011	
E21B1a010 G21B1a002	Faucet Aerator	Gas	HEA			0.156
E21B1a011	Faucet Aerator	Kerosene	HEA			0.156
E21B1a012	Faucet Aerator	Oil	HEA			0.156
E21B1a013	Faucet Aerator	Propane	HEA			0.156
E21A2a009	Faucet Aerator	Electric	HPwES	46.863	0.011	
E21A2a010 G21A2a002	Faucet Aerator	Gas	HPwES			0.156

E21A2a011	Faucet Aerator	Kerosene	HPwES			0.156
E21A2a012	Faucet Aerator	Oil	HPwES			0.156
E21A2a013	Faucet Aerator	Propane	HPwES			0.156

Measure Life:

The measure life is 7 years.[5]

Other Resource Impacts:

Residential annual water savings for faucet aerators is 586 gallons per unit.[3]

Impact Factors for Calculating Adjusted Gross Savings:[3 6]

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a009	Faucet Aerator	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.31	0.81
E21B1a010 G21B1a002	Faucet Aerator	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a011	Faucet Aerator	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a012	Faucet Aerator	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a013	Faucet Aerator	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a009	Faucet Aerator	Electric	HPwES	0.99	0.96	n/a	0.96	0.96	0.31	0.81
E21A2a010 G21A2a002	Faucet Aerator	Gas	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21A2a011	Faucet Aerator	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a012	Faucet Aerator	Oil	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a013	Faucet Aerator	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

In-service rates are 99% for HPwES programs and are 100% HEA programs based on evaluation

results.[3, 6]Realization Rates:

All PAs use a realization rate of 96% for HPwES program for electric fuel types, 114% for oil, propane and wood fuel types, and a realization rate of 91% for HEA program.[3 6]

Coincidence Factors:

A summer coincidence factor of 31% and a winter coincidence factor of 81% are utilized for faucet aerators with electric fuel type.[4]

Energy Load Shape:

See Appendix 1 "Water Heater – Electric".[4]

Endnotes:
1: In 1998, the Department of Energy adopted a maximum flow rate standard of 2.2 gpm at 60 psi for all faucets: 63 Federal Register 13307; March 18, 1998. https://www.epa.gov/sites/production/files/2017-02/documents/ws-specification-home-final-suppstatement-v1.0.pdf
2: WaterSense: Bathroom Faucets. https://www.epa.gov/watersense/bathroom-faucets
3: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL. https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
5: Faucet aerator is an add on measure. Measure life assumes 1/3 the life of the host equipment (faucet).
6: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL. https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf

1.17 Hot Water – Heat Pump Water Heater

Measure Code	
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Hot Water

Description:

Installation of an Energy Star ® certified heat pump storage water heater, either through direct installation programs to replace an electric resistance storage water heater, or as a lost opportunity retail offering.

Baseline Efficiency:

The direct install baseline efficiency case is a standard efficiency electric resistance storage hot water heater. The lost opportunity baseline is a blended mix of electric and fossil fuel water heating based on study results, used for retail offerings where customer-specific baselines are unknown.[1]

High Efficiency:

The high efficiency case is a high efficiency Energy Star ® certified heat pump storage water heater.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[1]

BC Measure ID	Measure Name	Program	ΔkWh	Summer kW	Winter kW	ΔMMBtu
E21B1a043	Heat Pump Water Heater	HEA	1,818	0.296	0.234	
E21A2a043	Heat Pump Water Heater	HPwES	1,818	0.296	0.234	
E21A3b007	Heat Pump Water Heater, 55 gallons or less, Energy Star, UEF	ES Products	1,818 kWh for retrofit 961 kWh for lost opportunity	0.296 for retrofit 0.175 for lost opportunity	0.234 for retrofit 0.134 for lost opportunity	2.149 for lost opportunity
E21A3b008	Heat Pump Water Heater, 55 gallons or more, Energy Star, UEF	ES Products	1,258 kWh for retrofit 565 kWh for lost opportunity	0.113 for retrofit 0.040 for lost opportunity	0.101 for retrofit 0.035 for lost opportunity	2.149 for lost opportunity

Measure Life:

The measure life is 13 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[3 4 5]

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a043	Heat Pump Water Heater (Retrofit)	HEA	1.00	0.91	n/a	0.91	0.91	1.00	1.00
E21A2a043	Heat Pump Water Heater (Retrofit)	HPwES	0.99	0.96	n/a	0.96	0.96	1.00	1.00
E21A3b007 E21A3b035	Heat Pump Water Heater, 55 gallons or less, Energy Star, UEF	ES Products	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21A3b008 E21A3b036	Heat Pump Water Heater, 55 gallons or more, Energy Star, UEF	ES Products	1.00	1.00	n/a	1.00	1.00	1.00	1.00

In-Service Rates:

Installations have 100% in service rate for ES Products unless an evaluation finds otherwise, 100% for HEA, and 99% for HPwES[3, 4].
.

Realization Rates:

All PAs use a realization rate of 96% for HPwES program and a realization rate of 91% for HEA program.[3 4] The ES Homes and ES Products programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Programs use coincidence factors of 100% because the deemed summer and winter kW values represent coincident peak demand reductions.[1]

Energy Load Shape:

See Appendix 1 – “Water Heater – Heat Pump”.[5]

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[6]

For HPWH delivered through midstream channels, the following factors apply.

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG

E21A3b007	Heat Pump Water Heater, 55 gallons or less, Energy Star, UEF	ES Products	0.23	0.00	0.00	0.77
E21A3b008	Heat Pump Water Heater, 55 gallons or more, Energy Star, UEF	ES Products	0.23	0.00	0.00	0.77

Endnotes:
1: R1614/R1613 CT HVAC and Water Heater Process and Impact Evaluation, West Hill Energy and Computing, EMI Consulting & Lexicon Energy Consulting, Jul. 19, 2018. pp. 8.6-8.8. https://www.energizect.com/connecticut-energy-efficiency-board/evaluation-reports; also see 2020 CT Program Savings Document, chapter 4.5.4 for savings for 80-gallon water heaters.
2: Navigant Consulting (2018). Water Heating, Boiler, and Furnace Cost Study (RES 19) Add-On Task 7: Residential Water Heater Analysis Memo. http://ma-eeac.org/wordpress/wp-content/uploads/RES19_Assembled_Report_2018-09-27.pdf
3: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
5: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
6: Michael’s Energy, June 26, 2020. Efficiency Maine HPWH Free-ridership and Baseline Assessment Results Memo. https://www.efficiencymaine.com/docs/Heat-Pump-Water-Heater-Free-ridership-and-Baseline-Assessment.pdf

Revision History

Revision Number	Issue Date	Description
21	1/14/2022	Measure names of the residential ES products heat pump water heater offerings updated to match implementation's naming conventions.
22	1/14/2022	Added BC Measure ID’s to encompass all measures in BC model.

1.18 Hot Water – Pipe Insulation

Measure Code	
Market	Residential
Program Type	Retrofit
Category	Hot Water

Description:

Installation of insulation on domestic hot water pipes.

Baseline Efficiency:

The baseline efficiency case is the existing uninsulated domestic hot water piping system located in non-conditioned spaces.

High Efficiency:

The high efficiency case is the domestic hot water piping system in unconditioned spaces with insulation installed.

Algorithms for Calculating Primary Energy Impact:

The programs use vendor calculated energy savings for these measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates domestic hot water loads and other key parameters. Should the vendor software be unavailable or unable to estimate a home's energy savings from pipe insulation, the following savings algorithm should be used. Unit savings are deemed based on study results.[1 2]

$$\Delta kW_{total} = Linear\ feet \times \Delta kW$$

$$\Delta kWh_{total} = Linear\ feet \times \Delta kWh$$

$$\Delta MMBtu_{total} = Linear\ feet \times \Delta MMBtu$$

Where:
Linear feet = Total length of pipe insulation (in feet)
ΔkWh, ΔkW, and ΔMMBtu per linear foot are as follows:

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
E21B1a037 E21A2a037	Pipe Insulation <3/4" Pipe Pipe Insulation >3/4" Pipe	Electric	HEA/HPwES	14.100 20.500	0.010	
E21B1a038	Pipe Insulation <3/4" Pipe Pipe Insulation >3/4" Pipe	Gas	HEA/HPwES			0.078 0.114

G21B1a011 E21A2a038 G21A2a011						
E21B1a039 E21A2a039	Pipe Insulation <3/4" Pipe Pipe Insulation >3/4" Pipe	Kerosene	HEA/HPwES			0.075 0.110
E21B1a040 E21A2a040	Pipe Insulation <3/4" Pipe Pipe Insulation >3/4" Pipe	Oil	HEA/HPwES			0.087 0.126
E21B1a041 E21A2a041	Pipe Insulation <3/4" Pipe Pipe Insulation >3/4" Pipe	Propane	HEA/HPwES			0.075 0.110

Measure Life:

The measure life is 15 years.[3]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[1 4]

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a037	Pipe Insulation	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.31	0.81
E21B1a038 G21B1a011	Pipe Insulation	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a039	Pipe Insulation	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a040	Pipe Insulation	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a041	Pipe Insulation	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a037	Pipe Insulation	Electric	HPwES	0.99	0.96	n/a	0.96	0.96	0.31	0.81
E21A2a038 G21A2a011	Pipe Insulation	Gas	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21A2a039	Pipe Insulation	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a040	Pipe Insulation	Oil	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a041	Pipe Insulation	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a

In-Service Rates:

In-service rates are 99% for HPwES programs and are 100% for HEA programs based on evaluation results.[1, 4].

Realization Rates:

All PAs use a realization rate of 96% for HPwES program electric fuel type, 114% for oil, propane and wood fuel types and 104% for gas fuel types, and a realization rate of 91% for HEA program.[1, 4]

Coincidence Factors:

A summer coincidence factor of 31% and a winter coincidence factor of 81% are utilized for pipe insulation with electric fuel type.[2]

Energy Load Shape:

See Appendix 1 – "Water Heater - Electric"

Endnotes:

1: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL
https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NHSaves-HPwES-Evaluation-Report-Final-20200611.pdf
2: Navigant Consulting,2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
3: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007.
https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
https://energy.mo.gov/sites/energy/files/measure-life-report-2007.pdf
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/20200729-NHSaves-HEA-Evaluation-Report-FINAL.pdf

1.19 Hot Water – Setback

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit
Category	Hot Water

Description:

Manual setback of the thermostat on a water heating device to reduce energy consumption.

Baseline Efficiency:

The baseline efficiency case is a water heater with a standard water temperature of 140°F.

High Efficiency:

The high efficiency case is a water heater with an adjusted water temperature of 125°F.

Algorithms for Calculating Primary Energy Impact:

The programs use vendor calculated energy savings for measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates domestic hot water loads and other key parameters. Should the vendor software be unavailable or unable to estimate a home's energy savings from hot water setback, the following deemed savings should be used, based on evaluation results.[1] Note: Savings are due to reduced standby losses, which are assumed to be constant over the year, so ΔkW = ΔkWh / 8760 hours.

BC ID	Measure Name	Program	Fuel Type	ΔkWh/unit	ΔkW	ΔMMBtu/unit
	Hot Water Setback (both dishwasher and clothes washer configuration)	HPwES HEA	Electricity	51.0	0.006	n/a
E21B1a042 E21A2a042	Hot Water Setback (clothes washer only)	HPwES HEA	Electricity	78.6	0.009	n/a
E21A2a062 E21B1a063	Hot Water Setback (clothes washer only)	HPwES HEA	Propane	n/a	n/a	0.411
E21A2a059 E21B1a060	Hot Water Setback (clothes washer only)	HPwES HEA	Gas	n/a	n/a	0.411
E21B1a062 E21A2a061	Hot Water Setback (clothes washer only)	HPwES HEA	Oil	n/a	n/a	0.411

E21B1a061 E21A2a060	Hot Water Setback (clothes washer only)	HPwES HEA	Kerosene	n/a	n/a	0.411

Measure Life:

The measure life of hot water setbacks for existing units and new equipment is two years. [2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[1]

BC Measure ID	Measure Name	Program	Fuel	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a042	Hot Water Setback, Electric	HEA	Electric	1.00	0.91	n/a	0.91	0.91	1.00	1.00
E21B1a063	Hot Water Setback, Propane	HEA	Propane	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a062	Hot Water Setback, Oil	HEA	Oil	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a060	Hot Water Setback, Gas	HEA	Gas	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1a061	Hot Water Setback, Kerosene	HEA	Kerosene	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a042	Hot Water Setback, Electric	HPwES	Electric	0.99	0.96	n/a	0.96	0.96	1.00	1.00
E21A2a062	Hot Water Setback, Propane	HPwES	Propane	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a061	Hot Water Setback, Oil	HPwES	Oil	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2a059	Hot Water Setback, Gas	HPwES	Gas	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21A2a060	Hot Water Setback, Kerosene	HPwES	Kerosene	0.99	n/a	1.14	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

In-service rates are 99% for HPwES programs and are 100% for HEA programs based on evaluation results.[1, 4]

<u>Realization Rates:</u>

All PAs use a realization rate of 96% for the HPwES program for electric, 114% for oil propane and wood fuel types, 104% for gas fuel types, and a realization rate of 91% for the HEA program.[1, 4]

Coincidence Factors:

Coincidence factors for electric hot water are assumed to be 100% because savings are from reduced standby losses, which are assumed to be constant over the year.

Energy Load Shape:

See Appendix 1 – "24 Hour Operation"[3]

Endnotes:
1: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
2: Illinois TRM Version 9.0, measure 5.4.6 water heater temperature setback. https://www.ilsag.info/technical-reference-manual/il-trm-version-9/
3: Savings are from reduced standby losses, which are assumed to be constant over the year.
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
23	1/14/2022	Added BC ID's and HEA and HPwES measures for the Kerosene fuel type.

1.20 Hot Water – Showerhead

Measure Code	
Market	Residential
Program Type	Retrofit
Category	Hot Water

Description:

An existing shower head with high flow rate is replaced with a new low flow shower head.

Baseline Efficiency:

The baseline efficiency case is the existing showerhead with a baseline flow rate of 2.5 gallons per minute (GPM).

High Efficiency:

The high efficiency case is a low flow shower head having a maximum flow rate of 2.0 GPM or less.

Algorithms for Calculating Primary Energy Impact:

The programs use vendor calculated energy savings for measures in the Residential Home Performance with ENERGY STAR and Home Energy Assistance programs. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates domestic hot water loads and other key parameters. Should the vendor software be unavailable or unable to estimate a home's energy savings from low flow showerheads, the following deemed savings should be used, based on evaluation results.[1] kW savings are calculated using the demand impact model.[2]

BC Measure ID	Measure Name	Hot Water Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
E21B1a016	Handheld Showerhead	Electric	HEA	145.226	0.050	
E21B1a017 G21B1a003	Handheld Showerhead	Gas	HEA			0.633
E21B1a018	Handheld Showerhead	Kerosene	HEA			0.633
E21B1a019	Handheld Showerhead	Oil	HEA			
E21B1a020	Handheld Showerhead	Propane	HEA			0.633
E21A2a016	Handheld Showerhead	Electric	HPwES	145.226	0.050	
E21A2a017 G21A2a003	Handheld Showerhead	Gas	HPwES			0.633
E21A2a018	Handheld Showerhead	Kerosene	HPwES			0.633
E21A2a019	Handheld Showerhead	Oil	HPwES			
E21A2a020	Handheld Showerhead	Propane	HPwES			0.633
E21B1a030	Low flow Showerhead	Electric	HEA	145.226	0.050	
E21B1a031 G21B1a010	Low flow Showerhead	Gas	HEA			0.633
E21B1a032	Low flow Showerhead	Kerosene	HEA			0.633
E21B1a033	Low flow Showerhead	Oil	HEA			
E21B1a034	Low flow Showerhead	Propane	HEA			0.633
E21A2a030	Low flow Showerhead	Electric	HPwES	145.226	0.050	
E21A2a031 G21A2a010	Low flow Showerhead	Gas	HPwES			0.633
E21A2a032	Low flow Showerhead	Kerosene	HPwES			0.633
E21A2a033	Low flow Showerhead	Oil	HPwES			
E21A2a034	Low flow Showerhead	Propane	HPwES			0.633

Measure Life:

The measure life is 15 years.[4]

Other Resource Impacts:

Annual water savings are 1,246 gallons per unit.[1]

Impact Factors for Calculating Adjusted Gross Savings:[1, 5]

BC Measure ID	Measure Name	Hot Water Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a016	Handheld showerhead	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.31	0.81
E21B1a017 G21B1a003 E21B1a018 E21B1a019 E21B1a020	Handheld showerhead	Gas Kerosene Oil Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a016	Handheld showerhead	Electric	HPwES	0.99	1.00	n/a	1.00	1.00	0.31	0.81
E21A2a017 G21A2a003 E21A2a018 E21A2a019 E21A2a020	Handheld showerhead	Gas Kerosene Oil Propane	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a
E21B1a030	Low flow Showerhead	Electric	HEA	1.00	0.91	n/a	0.91	0.91	0.31	0.81
E21B1a031 G21B1a010 E21B1a032 E21B1a033 E21B1a034	Low flow Showerhead	Gas Kerosene Oil Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2a030	Low flow Showerhead	Electric	HPwES	0.99	1.00	n/a	1.00	1.00	0.31	0.81
E21A2a031 G21A2a010 E21A2a032 E21A2a033 E21A2a034	Low flow Showerhead	Gas Kerosene Oil Propane	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

In-service rates are 99% for HPwES and are 100% for HEA based on evaluation results.[1, 5]

Realization Rates:

All PAs use a realization rate of 96% for HPwES for electric, 114% for oil, propane, and wood fuel types, 104% for gas fuel types and a realization rate of 91% for HEA.[1, 5]

Coincidence Factors:

A summer coincidence factor of 31% and a winter coincidence factor of 81% are utilized.[2]

Energy Load Shape:

See Appendix 1 "Water Heater – Electric".

Endnotes:
1: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL. kWh were estimated using the input values and methodology described in 'Table C-2. Algorithms and Inputs for Efficient Showerheads'.
3: Navigant Consulting,2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
4: Guidehouse, inc (2020). Massachusetts Comprehensive TRM Review - MA19R17-B-TRM. Prepared for the electric and gas program administrators of Massachusetts part of the residential evaluation program area.
5: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision History

Revision Number	Issue Date	Description
24	1/14/2022	Added missing BC measures ID's to the algorithms for primary energy impact tables.
25	1/14/2022	Updated typos in footnote numbering.

1.21 Hot Water –Water Heater

Measure Code	TBD
Market	Residential
Program Type	Retrofit/ Lost Opportunity
Category	Hot Water

Description:

Installation of a new high-efficiency natural gas tankless and storage water heaters.

Baseline Efficiency:

For indirect water heaters, the baseline efficiency case is the existing indirect water heater with EF of 0.6.[1]

For water heaters integrated with condensing boiler, the baseline efficiency case is an 85% AFUE rated boiler (79.3% AFUE actual) with a 0.6 EF water heater.[1] The ER baseline is an 80% AFUE rated boiler (77.4% AFUE actual) with either an indirect water heater or with a 0.55 EF water heater.

For tankless water heaters, the baseline efficiency case is a stand-alone tank water heater with a UEF of 0.63. For the early retirement portion, the baseline efficiency is an existing 0.58 UEF standalone water heater.

For standalone storage tank water heater, the baseline efficiency case is a stand-alone tank water heater with a UEF of 0.63. For the early retirement portion, the baseline efficiency is an existing 0.58 UEF standalone water heater.

High Efficiency:

The high efficiency case for indirect water heaters is an indirect water heater attached to an ENERGY STAR® rated forced hot water boiler.

For water heaters integrated with condensing boilers, the high efficiency case is an integrated water heater/boiler unit with a 90% AFUE condensing boiler and a 0.9 EF water heater or a 95% AFUE condensing boiler and a 0.95 EF water heater.

For tankless water heaters, the high efficiency case is a tankless water heater with UEF of 0.94.

For standalone storage tank water heater, the baseline efficiency case is a stand-alone water heater with EF ≥ 0.66.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[2] [3] Savings have been adjusted to reflect the mix of replace and failure and early retirement based on study results. There is an electric penalty associated with the gas on-demand tankless water heater to account for additional electrical consumption for power venting and electronic pilot ignition.

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
G21A3b012	Water Heater - Indirect (attached to ES FHW Boiler; Combined eff rating >=85% (EF=.82)	Gas	ES Products			4.0
G21A3b013	Water Heater - Integrated with Condensing Boiler >= 90% AFUE	Gas	ES Products			8.4
G21A3b014	Water Heater - Integrated with Condensing Boiler >= 95% AFUE	Gas	ES Products			12.8
G21A3b015	Condensing Water Heater (EF 0.95)	Gas	ES Products	-43.0[8]	-0.010[8]	7.0
G21A3b016	Stand Alone Storage Tank Water Heater (EF 0.67)	Gas	ES Products	-43.0[8]	-0.010[8]	3.0
G21A3b018	Water Heater - Tankless, On-Demand UEF >=. 87	Gas	ES Products	-43.0[8]	-0.010[8]	7.3
E21B1a096	Stand Alone Storage Water Heater	Electric	HEA			
E21B1a097	Stand Alone Storage Water Heater	Gas	HEA	-43.0[8]	-0.01[8]	2.5
E21B1a099	Stand Alone Storage Water Heater	Propane	HEA			
E21B1a098	Indirect Water Heater	Oil	HEA			4.7[3]
E21A2a082	Indirect Water Heater	Oil	HPwES			4.7[3]
E21A2a083	Indirect Water Heater	Propane	HPwES			4.0[3]

Measure Life:

The table shows the measure life for each measure.[4 5 6 7]

BC Measure ID	Measure Name	Fuel Type	Program	Measure Life

G21A3b012	Water Heater - Indirect (attached to ES FHW Boiler; Combined eff rating >=85% (EF=.82) (Retrofit)	Gas	ES Products	20
G21A3b013	Water Heater - Integrated with Condensing Boiler >= 90% AFUE (Retrofit)	Gas	ES Products	19
G21A3b014	Water Heater - Integrated with Condensing Boiler >= 95% AFUE (Retrofit)	Gas	ES Products	19
G21A3b015	Condensing Water Heater (EF 0.95)	Gas	ES Products	15
G21A3b016	Stand Alone Storage Tank Water Heater (EF 0.67)	Gas	ES Products	10
G21A3b018	Water Heater - Tankless, On-Demand >=.87	Gas	ES Products	19
E21B1a096	Stand Alone Storage Water Heater	Electric	HEA	13
E21B1a097	Stand Alone Storage Water Heater	Gas	HEA	13
E21B1a099	Stand Alone Storage Water Heater	Propane	HEA	13
E21B1a098	Indirect Water Heater	Oil	HEA	13
E21A2a082	Indirect Water Heater	Oil	HPwES	13
E21A2a083	Indirect Water Heater	Propane	HPwES	13

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21A3b012	Water Heater - Indirect (attached to ES FHW Boiler; Combined eff rating >=85% (EF=.82) (Retrofit)	Gas	ES Products	1.00	n/a	1.00	n/a	n/a	n/a	n/a

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21A3b013	Water Heater - Integrated with Condensing Boiler >= 90% AFUE (Retrofit)	Gas	ES Products	1.00	n/a	n/a	n/a	n/a	n/a	n/a
G21A3b014	Water Heater - Integrated with Condensing Boiler >= 95% AFUE (Retrofit)	Gas	ES Products	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21A3b015	Condensing Water Heater (EF 0.95)	Gas	ES Products	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21A3b016	Stand Alone Storage Tank Water Heater (EF 0.67)	Gas	ES Products	1.00	1.00	1.00	n/a	n/a	0.21	0.40
G21A3b018	Water Heater - Tankless, On-Demand >=.94 (New Construction)	Gas	ES Products	1.00	1.00	1.00	n/a	n/a	0.21	0.40
E21B1a096	Stand Alone Storage Water Heater	Electric	HEA	1.00	.91	n/a	n/a	n/a	0.21	0.40
E21B1a097	Stand Alone Storage Water Heater	Gas	HEA	1.00	n/a	.91	n/a	m/a	n/a	n/a
E21B1a099	Stand Alone Storage Water Heater	Propane	HEA	1.00	n/a	.91	n/a	m/a	n/a	n/a
E21B1a098	Indirect Water Heater	Oil	HEA	1.00	n/a	.91	n/a	m/a	n/a	n/a
E21A2a082	Indirect Water Heater	Oil	HPwES	1.00	n/a	.91	n/a	m/a	n/a	n/a
E21A2a083	Indirect Water Heater	Propane	HPwES	1.00	n/a	.91	n/a	m/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service-rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A summer coincidence factor of 21% and a winter coincidence factor of 40% are claimed for tankless and stand-alone storage water heaters.[8]

Energy Load Shape:

See Appendix 1 – “Water Heater - Natural Gas/Fuel Oil”.

Endnotes:

1: The 85% AFUE baseline represents value negotiated in MA for new boilers, which is applied to water heaters in this case.
2: Massachusetts Program Administrators (2018). 2019-2021 Gas HVAC and Water Heating Calculations Workbook. Workbook can be downloaded here: https://etrm.anbetrack.com/#/workarea/trm/MADPU/RES-WH-ODTWH/2020%20Report%20DRAFT%20WORKING%20TRM/version/4?measureName=Hot%20Water%20-%20On%20Demand%2FTankless%20Water%20Heater
3: Navigant (2018). Home Energy Service Impact Evaluation. Prepared for program administrators in Massachusetts. 2018_Navigant_HES_Impact_Evaluation
4: GDS Associates, Inc. (2009). Natural Gas Energy Efficiency Potential in Massachusetts. http://ma-eeac.org/wordpress/wp-content/uploads/5_Natural-Gas-EE-Potenial-in-MA.pdf
5: Environmental Protection Agency (2009). Life Cycle Cost Estimate for ENERGY STAR Qualified Boiler. https://www.energystar.gov/sites/default/files/asset/document/Savings_and_Cost_Estimate_Summary.pdf
6: DOE (2008). Energy Star Residential Water Heaters: Final Criteria Analysis and The Cadmus Group (2013). 2012 Residential Heating, Water Heating, and Cooling Equipment Evaluation: Net-to-Gross, Market Effects, and Equipment Replacement Timing.
7: Guidehouse, inc (2020). Massachusetts Comprehensive TRM Review - MA19R17-B-TRM. Prepared for the electric and gas program administrators of Massachusetts part of the residential evaluation program area.
8: Navigant Consulting (2018). Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	Issue Date	Description
26	1/14/2022	Fixed broken link in reference #3 for Navigant (2018). Home Energy Service Impact Evaluation. Prepared for program administrators in Massachusetts.
27	1/14/2022	Added entries for non-gas water heaters which had been omitted from the TRM. New entries include BC ID’s E21B1a096, E21B1a097, E21B1a099, E21B1a098, E21A2a082, E21A2a083

1.22 HVAC – Boiler

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

Installation of a new high efficiency forced hot water boiler for space heating.

Baseline Efficiency:

For Home Energy Assistance (HEA), the baseline efficiency is the existing system, consistent with the TREAT model used by the state Weatherization Assistance Program. For Home Performance with Energy STAR (HPwES) and Energy Star Products, the baseline reflects a bended value. The blended value uses an 84% AFUE rated boiler early replacement and an 85% AFUE boiler lost opportunity.[1]

High Efficiency:

The high efficiency case is a boiler with an AFUE rating of 90% or greater (i.e. a condensing boiler). Based on evaluation results the actual AFUE is 87.2% for a 90% AFUE rated boiler and 89.4% for a 95% AFUE rated boiler.

Algorithms for Calculating Primary Energy Impact:

Currently, HPwES uses deemed savings, while HEA uses modeled savings based on the TREAT model. Starting in mid-2021, HPwES will begin using modeled savings as well, based on a modified version of the TREAT model.

For Energy Star Products, unit savings are calculated based on deemed inputs and have been adjusted to reflect the mix of replace on failure and early replacement. [1]

BC Measure ID	Measure Name	Fuel Type	Program	ΔMMBtu/unit
E21B1b001 G21B1b001	Boiler Replacement, Forced Hot Water	Gas	HEA	Calculated
E21A2b001 G21A2b001	Boiler Replacement, Forced Hot Water	Gas	HPwES	12.1
E21B1b003	Boiler Replacement, Forced Hot Water	Oil	HEA	Calculated
E21A2b003	Boiler Replacement, Forced Hot Water	Oil	HPwES	2.7 currently, to be calculated once new model in place
E21B1b004 E21B1b002	Boiler Replacement, Forced Hot Water	Propane	HEA	Calculated

E21A2b004 E21A2b002	Boiler Replacement, Forced Hot Water	Propane	HPwES	16.7 currently, to be calculated once new model in place
G21A3b006	Condensing Boiler >=90% AFUE (Up to 300 MBh)	Gas	ES Products	12.1
G21A3b007	Condensing Boiler >=95% AFUE (Up to 300 MBh)	Gas	ES Products	14.8

Measure Life:

The measure life for all boilers is 19 years.[1]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b001 G21B1b001	Boiler Replacement, Forced Hot Water	Gas	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b001 G21A2b001	Boiler Replacement, Forced Hot Water	Gas	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a
E21B1b003	Boiler Replacement, Forced Hot Water	Oil	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b003	Boiler Replacement, Forced Hot Water	Oil	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a
E21B1b004	Boiler Replacement, Forced Hot Water	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b004	Boiler Replacement, Forced Hot Water	Propane	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a
E21B1b002	Boiler Replacement, Forced Hot Water	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b002	Boiler Replacement, Forced Hot Water	Kerosene	HPwES	0.99	n/a	1.00	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

ES Products uses a 100% in-service rate unless an evaluation finds otherwise. In-service rates are 99% for HPwES and are 100% for HEA based on evaluation results.[2, 3]

<u>Realization Rates:</u>

ES Products uses a 100% realization rate unless an evaluation finds otherwise. All PAs use a realization rate of 96% for HPwES and a realization rate of 91% for HEA.[2, 3]

<u>Coincidence Factors:</u>

No electric impacts are claimed.

Energy Load Shape:

No electric impacts are claimed.

Endnotes:
1: The 84% AFUE baseline is based on the New Hampshire Potential Study Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023, Volume III: Residential Market Baseline Study, June 11, 2020, p. 3-17. The 85% AFUE baseline represents value negotiated in MA for new boilers.
2: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
3: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
28	1/14/2022	Added omitted measures for Kerosene Boiler Replacements for HEA and HPwES

1.23 HVAC – Boiler Reset Control

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit
Category	HVAC

Description:

Installation of reset controls to automatically control boiler water temperature based on outdoor temperature or return water temperature in case of condensing boilers.

Baseline Efficiency:

The baseline efficiency case is a boiler without reset controls.

High Efficiency:

The high efficiency case is a boiler with reset controls.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[1]

BC Measure ID	Measure Name	Fuel Type	Program	ΔMMBtu/unit
G21A3b005	Boiler Reset Control	Gas	ES Products	5.1

Measure Life:

The measure life of reset controls installed on a new boiler is 15 years.[2]

BC Measure ID	Measure Name	Fuel	Program	EUL
G21A3b005	Boiler Reset Control	All	All	15

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21A3b005	Boiler Reset Control	Gas	ES Products	1.00	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service-rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1 “Non-Electric Measures”.

Endnotes:

1: Navigant Consulting, August 2018. Home Energy Services (HES) Impact Evaluation for Massachusetts. http://ma-eeac.org/wordpress/wp-content/uploads/RES34_HES-Impact-Evaluation-Report-with-ES_FINAL_29AUG2018.pdf

2: ACEEE, 2006. Emerging Technologies Report: Advanced Boiler Controls. Prepared for ACEEE.

Revision History

Revision Number	Date	Description
29	1/14/2022	Removed copy and paste formatting error. Baseline verbiage was originally in red text, change to black text.

1.24 HVAC – Duct Sealing

Measure Code	TBD
Market	Residential
Program Type	New Construction, Retrofit
Category	Building Shell

Description:

For existing ductwork in non-conditioned spaces, seal ductwork. This could include sealing leaky fixed ductwork with mastic or aerosol.

Baseline Efficiency:

The baseline efficiency case is existing, non-sealed (leaky) ductwork in unconditioned spaces (e.g. attic or basement).

High Efficiency:

The high efficiency condition is air sealed ductwork in unconditioned spaces.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[1,2]

BC ID	Measure Name	ΔkWh	ΔkWh[3]	ΔkWh
E21B1a084 E21A2a070	Duct Sealing, Cord Wood			3.9
E21B1a085 E21A2a071	Duct Sealing, Electric	442.00	0.31	
E21B1a086 E21A2a072	Duct Sealing, Gas			3.9
E21B1a087 E21A2a073	Duct Sealing, Kerosene			3.9
E21B1a088 E21A2a074	Duct Sealing, Oil			4.0
E21B1a089 E21A2a075	Duct Sealing, Propane			3.9
E21B1a090 E21A2a076	Duct Sealing, Wood Pellets			3.9

Measure Life:

The measure life for duct sealing is 20 years. [4]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1a084	Duct Sealing, Cord Wood	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1a085	Duct Sealing, Electric	HEA	1.00	.91	.91	.91	.91	0.24	0.25
E21B1a086	Duct Sealing, Gas	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1a087	Duct Sealing, Kerosene	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1a088	Duct Sealing, Oil	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1a089	Duct Sealing, Propane	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1a090	Duct Sealing, Wood Pellets	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21A2a070	Duct Sealing, Cord Wood	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a
E21A2a071	Duct Sealing, Electric	HPwES	0.99	0.96	1.00	0.96	0.96	0.24	0.25
E21A2a072	Duct Sealing, Gas	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a
E21A2a073	Duct Sealing, Kerosene	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a
E21A2a074	Duct Sealing, Oil	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a
E21A2a075	Duct Sealing, Propane	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a
E21A2a076	Duct Sealing, Wood Pellets	HPwES	0.99	0.96	1.00	0.96	0.96	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All PAs use a realization rate of 96% for HPwES for electric, 114% for oil, propane, and wood fuel types, 104% for gas fuel types and a realization rate of 91% for HEA.[1, 5]

Coincidence Factors:

Summer and winter coincidence factors are estimated using the demand allocation methodology described in the Demand Impact Model which is developed based on the Residential Baseline Study.

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

No electric impacts are claimed.

Endnotes:
1: The 84% AFUE baseline is based on the New Hampshire Potential Study Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023, Volume III: Residential Market Baseline Study, June 11, 2020, p. 3-17. The 85% AFUE baseline represents value negotiated in MA for new boilers.
2: Connecticut Program Savings Document, 2021. https://energizect.com/sites/default/files/2021-03/Final%202021%20PSD%20(Filed%203-01-2021).pdf - ESF 2% value was used compared to 5% used in the New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multifamily, and Commercial/Industrial Measures, Version 3, Issue Date – Jun. 1, 2015, p. 98.
3: Guidehouse (2020). Residential Baseline Study Phase 4
2020_Guidehouse_Residential_Baseline_Phase_4v
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. Weighted CF by end use (Table 3). http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
5**:** Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
6: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
58	1/14/2022	Omitted Measure Added

1.25 HVAC – Repair and Cleaning

Measure Code	TBD
Market	Residential
Program Type	New Construction, Retrofit
Category	HVAC

Description:

Undertaking of cleaning, tuning and repairs to heating systems.

Baseline Efficiency:

Existing heating system operating unsafely or one that has not been cleaned in greater than one year.

High Efficiency:

The high efficiency case is a heating system cleaned or repaired within the last year.

Algorithms for Calculating Primary Energy Impact:

Savings are vendor calculated using proprietary software. Savings are based on equipment tune-ups by adjusting the burner and cleaning the heat exchanger; therefore, the efficiency improves.

BC ID	Measure Name	Δtherms
E21B1b025	Gas LP HVAC Repair or Cleaning	Calculated
E21B1b024	Oil K1 HVAC Repair or Cleaning	Calculated

Where the software is unavailable, the following algorithms can be used:

$$ABTU_H = A \times HF \times (\frac{1}{AFUE_H}) \times ESF$$

Where:
$ABTU_H$ = Annual BTU savings – heating BTU/year
$AFUE_E$= Annual fuel utilization efficiency, existing (%) or use baseline value of 85% [1]
HF = Average heating factor based on home's heat load ($BTUft^2$)
ESF = Energy Savings factor, equal to .02[2]

Measure Life:

The measure life for a HVAC cleaning and repairs is 1 year.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b025	Gas LP HVAC Repair or Cleaning	HEA	1.00	.91	.91	.91	.91	n/a	n/a
E21B1b024	Oil K1 HVAC Repair or Cleaning	HPWES	0.99	0.96	1.00	0.96	0.96	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All PAs use a realization rate of 96% for HPwES for electric, 114% for oil, propane, and wood fuel types, 104% for gas fuel types and a realization rate of 91% for HEA.[1, 5]

Coincidence Factors:

Coincidence Factors are not applicable.

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

No electric impacts are claimed.

Endnotes:
1: The 84% AFUE baseline is based on the New Hampshire Potential Study Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023, Volume III: Residential Market Baseline Study, June 11, 2020, p. 3-17. The 85% AFUE baseline represents value negotiated in MA for new boilers.
2: Connecticut Program Savings Document, 2021. https://energizect.com/sites/default/files/2021-03/Final%202021%20PSD%20(Filed%203-01-2021).pdf - ESF 2% value was used compared to 5% used in the New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multifamily, and Commercial/Industrial Measures, Version 3, Issue Date – Jun. 1, 2015, p. 98.
3: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
4: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
30	1/14/2022	Omitted Measure Added

1.26 HVAC – ENERGY STAR Central Air Conditioning

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

The installation of a high efficiency ENERGY STAR central air conditioning (AC) system.

Baseline Efficiency:

For replace on failure retrofit, the baseline efficiency case is a Seasonal Energy Efficiency Ratio (SEER) 12.4 central air-conditioning unit.[1] For lost opportunity, the baseline is NH state building code of 14 SEER. For early retirement, if values are known, then baseline is the existing air-conditioning unit SEER over its remaining life, and a SEER 12.4 central air-conditioning unit for the remaining life of the new unit. If baseline values are unknown, the baseline case over its remaining life should be the average efficiency levels of units replaced in the previous calendar year.

High Efficiency:

The high efficiency case is a program qualified ENERGY STAR central air-conditioning unit. The minimum ENERGY STAR Seasonal Energy Efficiency Ratio (SEER) requirement for the program is 15.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = Tons \times 12\ kBtu/hr\ /\ Ton \times (1/SEER_{BASE} - 1/SEER_{EE}) \times Hours$
$\Delta kW = \Delta kWh \times$ Annual Maximum Demand Factor
Where:
Tons = Cooling capacity of the central AC equipment in tons. Use actual rebated tons or if unknown assume previous year average program rebated tonnage (for 2019, was 2.85 tons).[2]
SEERBASE = Seasonal Energy Efficiency Ratio (SEER).

- For replace on failure retrofit installation, baseline AC equipment should be SEER 12.4 equipment.
- For lost opportunity, baseline AC equipment should be SEER 14 equipment.
- For early replacement retrofit, baseline AC equipment is divided into two components:
    - For the remaining useful life of the replaced AC equipment:
        - if known, use the replaced (old) AC SEER value.
        - if unknown, assume previous calendar year average of the replaced (old) AC SEER value (for 2019 was SEER 10).
    - For the remaining useful life of the new AC equipment: baseline AC equipment should be 12.4 SEER

$SEER_{EE}$ = Seasonal Energy Efficiency Ratio (SEER) of new efficient AC equipment. Use actual rebated SEER, or if unknown, assume previous calendar year average (for 2019 was 17.1 SEER). [3]
Hours = Equivalent Full Load Hours (EFLH).

Savings Assumptions for Calculating Residential Central Air Conditioners:

BC Measure ID	Measure Name	Program	Tons	$SEER_{BASE}$	$SEER_{EE}$	Hours	Annual Max Demand Factor[9]
E21A3b015	ENERGY STAR Central AC	ENERGY STAR Products	Use actual, if unknown use 2.85	12.4	Use actual, if unknown use 17.1	385	0.001594
E21B1b023	ENERGY STAR Central AC, Early Retirement	HEA	Use actual, if unknown use 2.85	Use actual, if unknown use 10 for remaining useful life of replaced AC, 12.4 for remaining useful life of new AC	Use actual, if unknown use 17.1	385	0.001594
E21A2b021	ENERGY STAR Central AC, Early Retirement	HPwES	Use actual, if unknown use 2.85	Use actual, if unknown use 10 for remaining useful life of replaced AC, 12.4 for remaining useful life of new AC	Use actual, if unknown use 17.1	385	0.001594

Measure Life:

The table below includes the effective useful life (EUL) for central air-conditioning units which assumes a lost opportunity installation. Retrofit installations that meet early retirement criteria should receive a remaining useful life of 6 years for a total of 18-year life[5, 6]. To calculate lifetime savings for lost opportunity and replace on failure retrofit installations, use the full EUL of 18 years with the first row of savings assumptions (ENERGY STAR Central AC) above. For retrofit installations that meet early retirement criteria, lifetime savings are based on the sum of two components: 6 years with savings from the second row of savings assumptions above (ENERGY STAR Central AC, Early Retirement) and the remaining 12 years using the lost opportunity savings assumptions (ENERGY STAR Central AC).

BC Measure ID	Measure Name	Program	Measure Life (EUL)	Measure Life (RUL)
E21A3b015	ENERGY STAR Central AC	ES Products	18	n/a
E21B1b023	ENERGY STAR Central AC, Early Retirement	HEA	18	6
E21A2b021	ENERGY STAR Central AC, Early Retirement	HPwES	18	6

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b015	ENERGY STAR Central AC	ES Products	1.00	1.00	n/a	1.00	1.00	0.35	0.00
E21B1b023	ENERGY STAR Central AC, Early Retirement	HEA	1.00	0.91	n/a	0.91	0.91	0.35	0.00
E21A2b021	ENERGY STAR Central AC, Early Retirement	HPwES	0.99	0.96	n/a	0.96	0.96	0.35	0.00

In-Service Rates:

In-service rates are 100% for ES Products unless an evaluation finds otherwise, 100% for HEA[8], and 99%% for HPwES[7].

Realization Rates:

Realization rates are 100% for ES Products, 91% for HEA[8], and 96% for HPwES[7].

Coincidence Factors:

Summer coincidence factors are estimated using the RES1 Demand Impact Model Update.[9] The winter coincidence factor is assumed to be zero.

Energy Load Shape:

See Appendix 1 – “Central Air Conditioner/Heat Pump (Cooling)”.

Endnotes:

1: Itron 2020. New Hampshire Residential Baseline Study. Prepared for New Hampshire Evaluation, Measurement and Verification Working Group.
2: Average tonnage for Eversource 2019 rebated ENERGY STAR central AC according to tracking database summary report. Pulled February 10, 2020.
3: Average SEER for Eversource 2019 rebated ENERGY STAR central AC according to tracking database summary report. Pulled February 10, 2020.
4: Refer to Appendix 2. EFLH based on NH TMY3 Data.
https://www.energystar.gov/sites/default/uploads/buildings/old/files/CentralAC_Calculator.xls
EFLH Calculator tab in the EVT_CCHP MOP and Retrofit_2018_.xlsx.). Previous VT TRM was 375. Cadmus study showed much lower for heat pumps:
https://publicservice.vermont.gov/sites/dps/files/documents/2017%20Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf
5: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007.

https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
6: RUL is based on the 2019 MA TRM, Illinois TRM version 9.0, and NEEP TRM version 9.0, which all assume an RUL of one-third the EUL, or six years.
7: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
8: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
9: Navigant Consulting, 2018. RES1 Demand Impact Model Update. https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision History:

Revision Number	**Issued Date**	**Revision**
31	1/14/2022	Formatting, added correct BC ID's
32	1/14/2022	Updated baseline for lost opportunity to reflect NH Building code.
66	3/1/2022	Updated EFLH value used.

1.27 HVAC – ENERGY STAR Room Air Conditioning

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity/Retrofit
Category	HVAC

Description:

The installation of a high efficiency room air conditioning (AC) unit.

Baseline Efficiency:

The lost opportunity baseline efficiency case is a room AC unit meeting current federal standard, and the early replacement baseline is the existing inefficient unit.

High Efficiency:

The high efficiency case is a program-qualified ENERGY STAR room AC unit.

Algorithms for Calculating Primary Energy Impact:

Electric energy savings for a program-qualified ENERGY STAR room air-conditioning unit are deemed at 33 kWh per unit for lost opportunity. Unit savings are based on the Massachusetts eTRM value (36 kWh) adjusted to account for the cooling load differential between Massachusetts and New Hampshire.[1] Early replacement savings for HEA and HPwES are vendor calculated using proprietary software where the user inputs a minimum set of home-specific technical data. As an alternative, the deemed savings below should be used, based on evaluation results.[2]

Savings Assumptions for Calculating Residential ENERGY STAR Room Air Conditioners:

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW[3]
E21A3b016	ENERGY STAR Room AC	ES Products	33	0.06
E21B1a054	ENERGY STAR Room AC	HEA	113	0.18
E21A2a057	ENERGY STAR Room AC	HPwES	113	0.18

Measure Life:

The table below includes the effective useful life (EUL) for room air-conditioning units which assumes lost opportunity installation. The 3 year remaining useful life (RUL) for early replacement units is multiplied by the early replacement annual savings value above, and the remaining 6 years of the EUL for those units is multiplied by the lost opportunity savings value above.

BC Measure ID	Measure Name	Program	Measure Life (EUL) [7]	Measure Life (RUL)[4]
E21A3b016	ENERGY STAR Room AC	ES Products	9	n/a
E21B1a054	ENERGY STAR Room AC	HEA	9	3
E21A2a057	ENERGY STAR Room AC	HPwES	9	3

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b016	ENERGY STAR Room AC	ES Products	1.00	1.00	n/a	1.00	1.00	0.33	0.00
E21B1a054	ENERGY STAR Room AC	HEA	1.00	0.91	n/a	0.91	0.91	0.33	0.00
E21A2a057	ENERGY STAR Room AC	HPwES	0.99	0.96	n/a	0.96	0.96	0.33	0.00

In-Service Rates:

In-service rates are 100% for ES Products unless an evaluation finds otherwise, 100% for HEA[6], and 99%% for HPwES[5]

Realization Rates:

Realization rates are 100% for ES Product program until the measure is evaluated. Realization rates for all HEA programs are 91%[6] and for all HPwES programs are 96%[5] per evaluation results.

Coincidence Factors:

Summer coincidence factors is estimated using the RES1 Demand Impact Model Update.[3] The winter coincidence factor is assumed to be zero.

Energy Load Shape:

See Appendix 1 – "Room or Window Air Conditioner".

Endnotes:
1: Connecticut's 2019 Program Savings Document, March 1, 2019.
https://www.energizect.com/sites/default/files/2019%20PSD%20%283-1-19%29.pdf
Common cooling savings algorithms used in the Connecticut PSD show a directly proportional relationship between savings and cooling operational hours. We assume a similar directly proportional relationship between cooling operational hours (EFLH), cooling savings, and cooling degree days. The

New Hampshire CDD of 518 is based on the HPwES evaluation and the MA CDD is assumed to be the average of New Hampshire and Connecticut (603).
2: The Cadmus Group, Inc. (2015). Massachusetts Low-Income Multifamily Initiative Impact Evaluation. http://ma-eeac.org/wp-content/uploads/Low-Income-Multifamily-Impact-Evaluation4.pdf
3: Navigant Consulting, 2018. RES1 Demand Impact Model Update. https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf.
4: California Public Utilities Commission, 2014 Database for Energy-Efficient Resources, Feb. 4, 2014. Available at: http://www.deeresources.com/files/DEER2013codeUpdate/download/DEER2014-EUL-table-update_2014-02-05.xlsx last accessed Sep 3, 2020.
5: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
6: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
7: Environmental Protection Agency (2009). Life Cycle Cost Estimate for ENERGY STAR Room Air Conditioner. EPA_2009_Lifecycle_Cost_Estimate_for_ENERGY_STAR_Room_Air_Conditione

Revision Number	Issue Date	Description
33	1/14/2022	Updated HPwES RR in 'Realization Rate' sub section. The RR was correct in the table, but incorrect in the verbiage.

1.28 HVAC – Furnace

Measure Code	
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

Installation of a new high efficiency space heating furnace with an electronically commutated motor (ECM) for the fan.

Baseline Efficiency:

For Home Energy Assistance (HEA), the baseline efficiency is the existing system, consistent with the TREAT model used by the state Weatherization Assistance Program. For Home Performance with Energy STAR (HPwES) and Energy Star Products, the baseline reflects a bended value. The blended value uses an 83% AFUE rated furnace for early replacement and an 85% AFUE furnace for lost opportunity.[1]

High Efficiency:

The high efficiency case is a new furnace with AFUE ≥ 95%.

Algorithms for Calculating Primary Energy Impact:

Currently, HPwES uses deemed savings, while HEA uses modeled savings based on the TREAT model. Starting in mid-2021, HPwES will begin using modeled savings as well, based on a modified version of the TREAT model.

For Energy Star Products, unit savings are calculated based on deemed inputs based on a blended Early Retirement/Replace on Failure baseline that reflects the historical project mix.

Unit savings for Furnace ancillary savings measure are based on the 2020 HPwES study results.[2] Ancillary electric savings for furnace replacement measure are based on the 2018 ES Products evaluation study.[4]

BC Measure ID	Measure Name	Fuel	Program	ΔkWh	ΔkW	ΔMMBtu
E21B1b005 G21B1b002 E21A2b005 G21A2b002	Furnace Replacement	Gas	HEA HPwES	130.6 168	0.064	Calculated
E21B1b006 E21A2b006	Furnace Replacement	Kerosene	HEA HPwES	87.6 168	0.064	Calculated

E21B1b008 E21A2b008	Furnace Replacement	Propane	HEA HPwES	130.6 168	0.064	Calculated for HEA 6.3 for HPwES for now, will be calculated later
E21B1b007 E21A2b007	Furnace Replacement	Oil	HEA HPwES	130.6 168	0.064	Calculated for HEA 4.6 for HPwES for now, will be calculated later
G21A3b008	Furnace 95+ AFUE (<150) w/ECM Motor	Gas	ES Products	104.2	0.07	9.8
G21A3b009	Furnace 97+ AFUE (<150) w/ECM Motor	Gas	ES Products	104.2	0.07	10.3

Measure Life:

Measure life is 17 years based on MA study results.[4]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings: [2 5]

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b005 G21B1b002	Furnace Replacement	Gas	HEA	1.00	n/a	0.91	0.91	0.91	0.00	0.45
E21A2b005 G21A2b002	Furnace Replacement	Gas	HPwES	0.99	n/a	1.00	1.00	1.00	0.00	0.45
E21B1b006	Furnace Replacement	Kerosene	HEA	1.00	n/a	0.91	0.91	0.91	0.00	0.45
E21A2b006	Furnace Replacement	Kerosene	HPwES	0.99	n/a	1.00	1.00	1.00	0.00	0.45
E21B1b008	Furnace Replacement	Propane	HEA	1.00	n/a	0.91	0.91	0.91	0.00	0.45
E21A2b008	Furnace Replacement	Propane	HPwES	0.99	n/a	1.00	1.00	1.00	0.00	0.45
E21B1b007	Furnace Replacement	Oil	HEA	1.00	n/a	0.91	0.91	0.91	0.00	0.45
E21A2b007	Furnace Replacement	Oil	HPwES	0.99	n/a	1.00	1.00	1.00	0.00	0.45

In-Service Rates:

ES Products installations have a 100% in-service-rate unless an evaluation finds otherwise. In-service rates are 99% for HPwES and are 100% for HEA based on evaluation results.[2 5]

Realization Rates:

All PAs use a realization rate of 96% for HPwES program and a realization rate of 91% for HEA program.[2 5] ES Products installations have a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

The summer coincidence factor for ancillary electric savings is 0.00 and winter coincidence factor is 0.45.[6]

Energy Load Shape:

See Appendix 1 "Furnace Fan".

Endnotes:
1: The 83% AFUE baseline is based on the New Hampshire Potential Study Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023, Volume III: Residential Market Baseline Study, June 11, 2020, p. 3-14. The 85% AFUE baseline represents value negotiated in MA for new boilers, which is applied to furnaces in this case.
2: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
3: New Hampshire ENERGY STAR® Products Program 2016 Evaluation Report (2018).
4: Guidehouse, Inc (2020). Massachusetts Comprehensive TRM Review - MA19R17-B-TRM. Prepared for the electric and gas program administrators of Massachusetts part of the residential evaluation program area.
5:Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
6: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision Number	Issue Date	Description
34	1/14/2022	Corrected typo in E21B1b007 delta kWh savings. Originally read 6.700, should instead match the propane savings.

1.29 HVAC – Central Air-source Heat Pump

Measure Code	[Code]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

This measure includes the installation of a high-efficiency, central air-source heat pump unit (ASHP) to serve the heating and cooling loads of a residential unit. The electric savings for this measure are realized through the increased nameplate efficiency between the baseline and installed equipment. If a fossil-fuel based heating system is being partially or completely displaced by the new heat pump unit, fossil fuel savings and increased electric consumption will be realized.

Baseline Efficiency:

The baseline efficiency varies as a function of replacement scenario.

For lost opportunity or replace on failure, the baseline is a code-compliant 2.8-ton, SEER 14, HSPF 8.2 heat pump unit. [3]

For retrofit installations in homes with electric resistance heating, the baseline is an electric heating system with COP = 1, which converts to an HSPF value of 3.412 Btu/w-h.[4] The cooling baseline is project-specific based on the existing equipment.

For retrofit installations in oil or propane-heated homes, the utilities are proposing a limited pilot offering starting in 2021. The heating and cooling baselines are project-specific. Estimated savings have been developed based on secondary research,[10] and will be updated with primary research on pilot participants, pending pilot approval.

High Efficiency:

The high efficiency (or energy efficient) case is the site-specific air-source heat pump unit. For full displacement, the heat pump must meet cold-climate heat pump standards, such as those on the NHSaves qualified product list.

Algorithms for Calculating Primary Energy Impact:

The savings for this measure are attributable to the increase in nameplate efficiency between the baseline and installed units. The savings are based on the energy efficient heat pump serving both the cooling and heating loads of the house.

The algorithm for calculating electric demand savings is:

$$\Delta kW = \max\left(\Delta kW_{cool} \; or \; \Delta kW_{heat}\right)$$

$$\Delta kW_{cool} = Cap_{cool} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

For retrofit applications where cooling is absent in the preexisting case, the term ($1/EER_{BASE}$) = 0

$$\Delta kW_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right)$$

$$Cap_{heat} = Cap_{cool} \times 1.0 \text{ if unit is a cold climate air-source heat pump}$$
$$Cap_{heat} = Cap_{cool} \times 0.9 \text{ for all other air-source heat pump}$$

Where:
ΔkW_{cool} = Gross annual cooling demand savings for air-source heat pump unit
ΔkW_{heat} = Gross annual heating demand savings for air-source heat pump unit
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient air-source heat pump unit, from equipment specifications
Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient air-source pump unit, from equipment specifications. Use equation to convert from cooling capacity value if standard equipment literature does not provide this value.
EER_{BASE} = Energy Efficiency Ratio of the baseline cooling equipment
EER_{EE} = Energy Efficiency Ratio of the energy efficient air-source heat pump unit, from equipment specifications
$HSPF_{BASE}$ = Heating Seasonal Performance Factor of baseline heat pump equipment
$HSPF_{EE}$ = Heating Seasonal Performance Factor of energy efficient air-source heat pump unit, from equipment specifications

The algorithm for calculating annual electric energy savings is:

$$\Delta kWh_{cool} = Cap_{cool} \times \left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right) \times EFLH_{cool}$$

For retrofit applications where cooling is absent in the preexisting case, the term ($1/SEER_{BASE}$) = 0

$$\Delta kWh_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right) \times EFLH_{heat}$$

If fossil fuel heating baseline, the term ($1/HSPF_{BASE}$) = 0 and the fossil fuel savings are:

$$\Delta MMBtu_{heat} = \frac{Cap_{heat}}{AFUE} \times EFLH_{heat} \times 10^{-3}$$

$$Cap_{heat} = Cap_{cool} \times 1.0 \text{ if unit is a cold climate air-source heat pump}$$
$$Cap_{heat} = Cap_{cool} \times 0.9 \text{ for all other air-source heat pump}$$

Where:
ΔkWh_{cool} = Gross annual cooling savings for air-source heat pump unit
ΔkWh_{heat} = Gross annual heating savings for air-source heat pump unit

$\Delta MMBtu_{heat}$ = Gross annual heating savings resulting from the decrease in fuel consumption due to the partial or complete displacement of the heating load by the energy efficient air-source heat pump unit.
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient air-source heat pump unit, from equipment specifications
Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient air-source pump unit, from equipment specifications. Use equation to convert from cooling capacity value if standard equipment literature does not provide this value.
$SEER_{BASE}$ = Seasonal Energy Efficiency Ratio of baseline cooling equipment
$SEER_{EE}$ = Seasonal Energy Efficiency Ratio of energy efficient air-source heat pump unit, from equipment specifications
$HSPF_{BASE}$ = Heating Seasonal Performance Factor of baseline heat pump equipment
$HSPF_{EE}$ = Heating Seasonal Performance Factor of energy efficient air-source heat pump unit, from equipment specifications
$EFLH_{cool}$ = Equivalent Full Load Hours for cooling.
$EFLH_{heat}$ = Equivalent Full Load Hours for heating.
$AFUE$ = Annual fuel utilization efficiency of replaced fossil fuel heating system
0.9 = Conversion factor[1] to convert cooling capacity to heating capacity for non-cold climate, air-source heat pump units not meeting standards similar to NEEP's cold climate air source heat pump (ccASHP) product list. The conversion factor for ccASHP meeting standards similar to NEEP's is 1.0.
10^{-3} = Conversion factor from kBtu to MMBtu

Heat Pump Type	Cooling Capacity Range	Parameter	Value			Units
			1. Lost Opportunity	2. Retrofit - Resistance	3. Retrofit – Fossil Fuel	
Air-source Heat Pump	All sizes	EER_{BASE}	11.76[2]	-	-	Btu/W-h
		$SEER_{BASE}$	14.00[3]	-	-	Btu/W-h
		$HSPF_{BASE}$	8.20[3]	3.412[4]	-	Btu/W-h
		AFUE	N/A	N/A	75%[5]	
		$EFLH_{cool}$	280[6]			Hours
		$EFLH_{heat}$	1020[7]			Hours

Measure Life:

The measure life of a new heat pump unit is 18 years.[8]

BC Measure ID	Measure Name	Program	Measure Life
E21A3b003	Air-source Heat Pump – Lost Opportunity (Cooling)	ES Products	18

E21A3b004	Air-source Heat Pump – Lost Opportunity (Heating)	ES Products	18
E21A3b034	Air-source Heat Pump – Retrofit Resistance	ES Products	18
E21B1b021	Ductless Mini-split Heat Pump (cooling)	HEA	18
E21B1b022	Ductless Mini-split Heat Pump (heating)	HEA	18

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b003	Air-source Heat Pump – Lost Opportunity (Cooling)	ES Products	1.00	1.00	1.00	1.00	1.00	0.346	0.00
E21A3b004	Air-source Heat Pump –Lost Opportunity (Heating)	ES Products	1.00	1.00	1.00	1.00	1.00	0.00	0.620
E21A3b034	Air-source Heat Pump – Retrofit Resistance	ES Products	1.00	1.00	1.00	1.00	1.00	0.346	0.620
E21B1b021	Ductless Mini-split Heat Pump (cooling)	HEA	1.00	0.91	0.91	0.91	0.91	0.346	n/a
E21B1b022	Ductless Mini-split Heat Pump (heating)	HEA	1.00	0.91	0.91	0.91	0.91	n/a	0.620

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

ES Products use a 100% realization, HEA programs use a realization rate of .91.[11]

Coincidence Factors:

A coincidence factor of 34.60% during cooling season and a coincidence factor of 62.0% for the heating season should be applied. [9]

Energy Load Shape:

See Appendix 1 – "Central Heat Pump"

Endnotes:
1: Conversion factor is based on internal ERS analysis of Mass Save and NEEP ccASHP product data.
2: Since IECC does not provide EER requirements for heat pumps <65kBtu/h, the following conversion is used: $EER = -0.02 \times SEER^2 + 1.12 \times SEER$. Source for the calculation is https://www.nrel.gov/docs/fy11osti/49246.pdf
3: International Energy Conservation Code 2015, table C403.2.3(2) Minimum Efficiency Requirements: Electrically Operated Unitary and Applied Heat Pumps
4: Electric heating system has COP = 1, which converts to an HSPF value of 3.412 Btu/w-h
5: MA TRM DMSHP measure. This value in the MA TRM has been agreed upon by EEAC consultants and represents actual fossil fuel heating equipment efficiencies which include efficiency degradation over the age of the equipment. MA TRM DMSHP.
6: Cooling hours from NY TRM v7 Appendix G for Single family homes. The average of cooling hour values for the cities of Albany and Massena are assumed to be representative of NH, because they lie roughly along the same latitudes as endpoints of NH.
7: Heating hours from NY TRM v7 Appendix G for Single family homes. The average of heating hour values for the cities of Albany and Massena are assumed to be representative of NH, because they lie roughly along the same latitudes as the endpoints of NH.
8: GDS Associates, Inc. (2007). Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
9: Coincidence Factors obtained from Navigant Consulting (2018), Demand Impact Model Update (for Central Air Conditioner/Heat Pump (Cooling) and Ductless Mini Split Heat Pumps (Heating)). The calculation of Coincidence Factors can be found in MA PAs' 2019-2021 Plan Electric Heating and Cooling Savings Workbook (2018)
10: Navigant, Energy Optimization. Sep. 12, 2019. See https://puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOSTARIFFS/17-136_2019-10-31_STAFF_NH_ENERGY_OPTIMIZATION_STUDY.PDF and https://puc.nh.gov/Electric/Reports/20190805-PUCElectric-NH-Energy-Optimization-Model.xlsx.
11: :Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
35	1/14/2022	Updated SEER to EER conversion factor used.
36	1/14/2022	Added omitted ductless mini split heating only and cooling only measures
67	3/1/2022	Added values for EFLH.

1.30 HVAC – Ductless Mini-Split Heat Pump

Measure Code	[Code]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

This measure includes the installation of a high-efficiency, ductless, mini-split heat pump unit (DMSHP) to serve the heating and cooling loads of a residential unit. The savings for this measure are realized through the increased nameplate efficiency between the baseline and installed equipment. If a fossil-fuel based heating system is being partially or completely displaced by the new heat pump unit, fossil fuel savings and electric consumption increases will be realized.

Baseline Efficiency:

The baseline efficiency varies as a function of replacement scenario.

For lost opportunity or replace on failure, the baseline is a code-compliant 2.2-ton, SEER 14, HSPF 8.2 heat pump unit. [3]

For retrofit installations in homes with electric resistance heating, the baseline is an electric heating system with COP = 1, which converts to an HSPF value of 3.412 Btu/w-h.[4] The cooling baseline is project-specific based on the existing equipment.

For retrofit installations in oil or propane-heated homes, the utilities are proposing a limited pilot offering starting in 2021. The heating and cooling baselines are project-specific. Estimated savings have been developed based on secondary research,[10] and will be updated with primary research on pilot participants, pending pilot approval.

High Efficiency:

The high efficiency (or energy efficient) case is the site-specific ductless, mini-split heat pump unit. For full displacement, the heat pump must meet cold-climate heat pump standards, such as those on the NHSaves qualified product list.

Algorithms for Calculating Primary Energy Impact:

The savings for this measure are attributable to the increase in nameplate efficiency between the baseline and installed units. The savings are based on the energy efficient heat pump serving both the cooling and heating loads of the house.

The algorithm for calculating electric demand savings is:

$$\Delta kW = \max\left(\Delta kW_{cool}\ or\ \Delta kW_{heat}\right)$$

$$\Delta kW_{cool} = Cap_{cool} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

For retrofit applications where cooling is absent in the preexisting case, the term ($1/EER_{BASE}$) = 0

$$\Delta kW_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right)$$

$Cap_{heat} = Cap_{cool} \times 1.0$ if unit is a cold climate ductless mini split heat pump
$Cap_{heat} = Cap_{cool} \times 0.9$ for all other ductless mini split heat pump

Where:
ΔkW_{cool} = Gross annual cooling demand savings for ductless, mini-split heat pump unit
ΔkW_{heat} = Gross annual heating demand savings for ductless, mini-split heat pump unit
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient ductless, mini-split heat pump unit, from equipment specifications
Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient ductless, mini-split pump unit, from equipment specifications. Use equation to convert from cooling capacity value if standard equipment literature does not provide this value.
EER_{BASE} = Energy Efficiency Ratio of the baseline cooling equipment
EER_{EE} = Energy Efficiency Ratio of the energy efficient ductless, mini-split heat pump unit, from equipment specifications
$HSPF_{BASE}$ = Heating Seasonal Performance Factor of baseline heat pump equipment
$HSPF_{EE}$ = Heating Seasonal Performance Factor of energy efficient ductless, mini-split heat pump unit, from equipment specifications

The algorithms for calculating annual cooling and heating electric energy savings are as follows:

$$\Delta kWh_{cool} = Cap_{cool} \times \left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right) \times EFLH_{cool}$$

For retrofit applications where cooling is absent in the preexisting case, the term ($1/SEER_{BASE}$) = 0

$$\Delta kWh_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right) \times EFLH_{heat}$$

If fossil fuel heating baseline, the factor ($1/HSPF_{BASE}$) = 0 and the fossil fuel savings are:

$$\Delta MMBtu_{heat} = \frac{Cap_{heat}}{AFUE} \times EFLH_{heat} \times 10^{-3}$$

$Cap_{heat} = Cap_{cool} \times 1.0$ if unit is a cold climate ductless mini split heat pump
$Cap_{heat} = Cap_{cool} \times 0.9$ for all other ductless mini split heat pump

Where:
ΔkWh_{cool} = Gross annual cooling savings for ductless, mini-split heat pump unit
ΔkWh_{heat} = Gross annual heating savings for ductless, mini-split heat pump unit
$\Delta MMBtu_{heat}$ = Gross annual heating savings resulting from the decrease in fuel consumption due to the partial or complete displacement of the heating load by the energy efficient ductless, mini-split heat pump unit.

Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient ductless, mini-split heat pump unit, from equipment specifications

Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient ductless, mini-split pump unit, from equipment specifications. Use equation to convert from cooling capacity value if standard equipment literature does not provide this value.
$SEER_{BASE}$ = Seasonal Energy Efficiency Ratio of baseline cooling equipment
$SEER_{EE}$ = Seasonal Energy Efficiency Ratio of energy efficient ductless, mini-split heat pump unit, from equipment specifications
$HSPF_{BASE}$ = Heating Seasonal Performance Factor of baseline heat pump equipment
$HSPF_{EE}$ = Heating Seasonal Performance Factor of energy efficient ductless, mini-split heat pump unit, from equipment specifications
$EFLH_{cool}$ = Equivalent Full Load Hours for cooling.
$EFLH_{heat}$ = Equivalent Full Load Hours for heating (Note: The algorithm assumes higher heating hours for full displacement scenarios, where heat pump meets over 90 percent of annual space heating needs and meets cold climate heat pump standards).
$AFUE$ = Annual fuel utilization efficiency of replaced fossil fuel heating system
0.9 = Conversion factor[1] to convert cooling capacity to heating capacity for non-cold climate, ductless heat pump units not meeting standards similar to NEEP's cold climate air source heat pump (ccASHP) product list. The conversion factor for ccASHP meeting standards similar to NEEP's is 1.0.
10^{-3} = Conversion factor from kBtu to MMBtu

Heat Pump Type	Cooling Capacity Range	Parameter	Value			Units
			1. Lost Opportunity	2. Retrofit - Resistance	3. Retrofit – Fossil Fuel	Units
Ductless Mini Split	All sizes	EER_{BASE}	11.76[2]	-	-	Btu/W-h
		$SEER_{BASE}$	14.00[3]	-	-	Btu/W-h
		$HSPF_{BASE}$	8.20[3]	3.412[4]	-	Btu/W-h
		AFUE	N/A	N/A	75%[5]	
		$EFLH_{cool}$	218[6]			Hours
		$EFLH_{heat, partial}$	535[7]			Hours
		$EFLH_{heat, full}$	1,117[7]			Hours

Measure Life:

The table below lists the measure life of the ductless mini-split heat pump equipment. [8]

BC Measure ID	Measure Name	Program	Measure Life
E21A3b005	Ductless Mini-split Heat Pump (cooling) - Lost Opportunity	ES Products	18
E21A3b006	Ductless Mini-split Heat Pump (heating) - Lost Opportunity	ES Products	18
E21A3b031	Ductless Mini-split Heat Pump - Retrofit Resistance	ES Products	18

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b005	Ductless Mini-split Heat Pump (cooling) - Lost Opportunity	ES Products	1.00	1.00	1.00	1.00	1.00	0.29	0.00
E21A3b006	Ductless Mini-split Heat Pump (heating) - Lost Opportunity	ES Products	1.00	1.00	1.00	1.00	1.00	0.00	0.62
E21A3b031	Ductless Mini-split Heat Pump - Retrofit Resistance	ES Products	1.00	1.00	1.00	1.00	1.00	0.29	0.62

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factor of 29% during cooling season and a coincidence factor of 62% for the heating season should be applied. [9]

Energy Load Shape:

For cooling, see Appendix 1 – Mini-Split Air Conditioner/Heat Pump (Cooling)
For heating, see Appendix 1 – Mini-Split Heat Pump (Heating)

Endnotes:
1: Conversion factor is based on internal ERS analysis of Mass Save and NEEP ccASHP product data.

2: Since IECC does not provide EER requirements for heat pumps <65kBtu/h, the following conversion is used: $EER = -0.02 \times SEER^2 + 1.12 \times SEER$. Source for the calculation is https://www.nrel.gov/docs/fy11osti/49246.pdf3: International Energy Conservation Code 2015, table C403.2.3(2) Minimum Efficiency Requirements: Electrically Operated Unitary and Applied Heat Pumps
4: Electric heating system has COP = 1, which converts to an HSPF value of 3.412 Btu/w-h
5: MA TRM DMSHP measure. This value in the MA TRM has been agreed upon by EEAC consultants and represents actual fossil fuel heating equipment efficiencies which include efficiency degradation over the age of the equipment. MA TRM DMSHP.
6: Cooling hours from Cadmus Group (2016), Ductless Mini-Split Heat Pump Impact Evaluation, December 30, 2016. Cadmus_2016_DMSHP_Impact_Evaluation
7: Heating hours from Navigant Consulting (2018), Quick Hit Study: Ductless Mini-Split Heat Pump Survey (RES 29), March 30, 2018. Assumes higher heating hours for displacement of electric heat based on top 25% EFLH (heating) reported in Cadmus Group (2016), Ductless Mini-Split Heat Pump Impact Evaluation, December 30, 2016. Navigant_2018_DMSHP_Survey.
8: GDS Associates, Inc. (2007). Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
9: Coincidence factors come from the Navigant Demand Impact model analysis spreadsheet – MA, Aug 2018.
10: Navigant, Energy Optimization. Sep. 12, 2019. See https://puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOSTARIFFS/17-136_2019-10-31_STAFF_NH_ENERGY_OPTIMIZATION_STUDY.PDF and https://puc.nh.gov/Electric/Reports/20190805-PUCElectric-NH-Energy-Optimization-Model.xlsx.

Revision History:

Revision Number	Issue Date	Description
37	1/14/2022	Updated SEER to EER conversion factor used.
68	3/1/2022	Added values for EFLH.

1.31 HVAC – Heat Recovery Ventilator

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	HVAC

Description:

Heat recovery ventilators (HRVs) and energy recovery ventilators (ERVs) can help make mechanical ventilation more cost effective by reclaiming energy from exhaust airflows.

Baseline Efficiency:

The baseline efficiency case is an ASHRAE 62.2-compliant exhaust fan system with no heat recovery.

High Efficiency:

The high efficiency case is an exhaust fan system with heat recovery.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[1]

BC Measure ID	Measure Name	Program	Δmmbtu
G21A3b010	Heat Recovery Ventilator	ES Products	7.7

Measure Life:

The measure life is 20 years[1].

Other Resource Impacts:

An electric penalty results due to the electricity consumed by the system fans[1].

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh/Unit	ΔkW/Unit
G21A3b010	Heat Recovery Ventilator	Electric	ES Products	-133	-0.10

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21A3b010	Heat Recovery Ventilator	ES Products	1.00	1.00	1.00	1.00	1.00	0.34	0.21

In-Service Rates:

All installations have a 100% in-service-rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Summer and winter coincidence factors are estimated using demand allocation methodology described by the Cadmus Demand Impact Model (2012) prepared for MA Program Administrators.

Energy Load Shape:

See Appendix 1.

Endnotes:
1: Guidehouse, August 2020. Comprehensive TRM Review MA19R17-B-TRM. Prepared for The Electric and Gas Program Administrators of Massachusetts.

1.32 HVAC- Swimming Pool Heater

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Lost Opportunity
Category	Custom

Description:

The installation of a high efficiency heat pump or gas swimming pool heater.

Baseline Efficiency:

The base case is a new, standard efficiency electric resistance hot water heater.

High Efficiency:

The high efficiency case is a heat pump or gas-fired water heater.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[1]

Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21A3b009	Heat Pump Swimming Pool Heater, <55 gallon, Energy Star, UEF 2.00	ES Products	1592	0.100
E21A3b009	Heat Pump Swimming Pool Heater, >55 gallon, UEF 2.70	ES Products	197	0.018

Measure Life:

The measure life is 13 years[1].

Other Resource Impacts:

The Gas Swimming Pool Heater measure increases gas consumption by 20.1 MMBtu/year.[1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3b009	Heat Pump Swimming Pool Heater	ES Products	1.00	1.00	n/a	1.00	0.00	0.00	0.00
G21A3b016	Gas Swimming Pool Heater	ES Products	1.00	n/a	1.00	1.00	0.00	0.00	0.00

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

The programs assume no summer or winter peak savings because it is assumed heaters are not used during summer peak periods and do not operate during the winter.

Energy Load Shape:

See Appendix 1.

Endnotes:
1: Navigant Consulting, 2018. Water Heating, Boiler, and Furnace Cost Study (RES 19) Appendix E, Add-On Task 7: Residential Water Heater Analysis Memo. 2018_Navigant_Water_Heater_Analysis_Memo http://ma-eeac.org/wordpress/wp-content/uploads/RES19_Assembled_Report_2018-09-27.pdf

1.33 Lighting - Fixture

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Lighting

Description:

The installation of Light-Emitting Diode (LED) fixtures, which offer comparable luminosity to incandescent and halogen fixtures at significantly less wattage and significantly longer lifetimes.

Baseline Efficiency:

The baseline efficiency case for a lost opportunity LED fixture is a combination of an incandescent fixture, halogen fixture, and a compact fluorescent fixture. The baseline efficiency case for a retrofit LED fixture is a combination of an incandescent fixture and halogen fixture.

High Efficiency:

The high efficiency case is an ENERGY STAR ® rated LED fixture.

Algorithms for Calculating Primary Energy Impact:

Unit savings are based on the algorithm below. Demand savings are derived from the Navigant Demand Impact Model.

Vendor calculated unit savings are calculated using the following algorithms and assumptions:

$\Delta kWh = ((Watts\_Ineff - Watts\_EE) \times HOU)))/1000 \times Qty\_Bulbs \times 365$

$\Delta kW = \Delta kWh \times kW/kWh$

kW/kWh = Average kW reduction per kWh reduction: 0.00025 kW/kWh

Watts_Ineff = Rated watts of inefficient bulbs (either removed, through retrofit, or assumed to have been installed, through lost opportunity)

Watts_EE = Rated watts of efficient bulbs installed

Qty_Bulbs = Number of bulbs per fixture

365 = Days per year

HOU = Daily hours of use. The hours of use are largely based on recent NH evaluation studies for the ENERGY STAR Products Program and the Home Performance with ENERGY STAR Program, as well as increased hours of operation for ENERGY STAR Products to account for cross-sector sales at retailers (i.e., businesses purchasing program incented fixtures). The direct installation delivery strategies (HPwES) are based on residential hours only but reflect higher hours of use since the programs direct contractors to only replace fixtures that are used for at least three hours per day. The following summarizes the key assumptions for daily hours of use:[1]

- Lost opportunity LEDs installed in residential applications: 1.75 hours/day
- Lost opportunity LEDs installed in commercial applications (7% of all lost opportunity fixtures): 7 hours/day
- Retrofit HPwES LEDs (all installed in residential applications): 3.0 hours/day
- Retrofit HEA LEDs: (all installed in residential applications): 3.0 hours/day

Delta watts (WattsINEFF – WattsEE) are broken out by delivery strategy, and reflect a mix of program fixture wattages (for the efficient wattage), removed fixtures (for retrofit inefficient fixtures), and a blended mix of incandescents, halogens, and CFLs that would have been purchased in absence of the program measure.[2]

BC Measure ID	Measure Name	Program	Delta Watts per Fixture	Daily HOU	Number of Bulbs	ΔkWh	ΔkW
E21A3a009	LED Fixture	ES Products	34.2	2.1	1	26.4	0.007
E21A2a048	LED Fixture	HPwES	34.2	3	1	37.4	0.010
E21B1a048	LED Fixture	HEA	Vendor Calculated				
E21A3a010	LED Fixture (Hard to Reach)	ES Products	34.2	2.1	1	26.4	0.007
E21A1a024	LED Fixture	ES Homes	8.55	1.75	1	5.5	0.001

Measure Life:

The table below summarizes the measure lives for each of the measures listed above. Note these measure lives have been adjusted to account for the differential in measure life between the inefficient fixtures and LED fixtures (as well as the remaining useful life in the retrofit cases), and the potential for future lighting standards to lead the same sockets reached through the program to have been occupied by an LED in a period shorter than the technical life of the LED.[3]

BC Measure ID	Measure Name	Program	Adjusted Measure Life
E21A3a009	LED Fixture	ES Products	3
E21A2a048 E21B1a048	LED Fixture	HPwES/HEA	2
E21A3a010	LED Fixture (Hard to Reach)	ES Products	3
E21A1a024	LED Fixture	ES Homes	3

Other Resource Impacts:

Based on the 2018 NH Energy Star Products Program Evaluation report, fossil fuel interactive penalties for residential lighting programs are -2,272 Btu/kWh saved.[8]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3a009	LED Fixture	ES Products	1.00	1.00	n/a	1.00	1.00	0.55	0.85
E21A2a048	LED Fixture	HPwES	0.99	1.00	n/a	1.00	1.00	0.55	0.85
E21B1a048	LED Fixture	HEA	1.00	0.91	n/a	0.91	0.91	0.55	0.85
E21A3a010	LED Fixture (Hard to Reach)	ES Products	1.00	1.00	n/a	1.00	1.00	0.55	0.85
E21A1a024	LED Fixture	ES Homes	1.00	1.00	n/a	1.00	1.00	0.55	0.85

In-Service Rates:

All HEA installations use an in-service rate of 100% because HEA realization rates account for uninstalled measures. All HPwES installations use in-service rate of 99% based on evaluation results. [5 9] All other installations have a 100% in-service rate unless an evaluation finds otherwise.[4]

Realization Rates:

Based on evaluation results, all HEA installations use a realization rate of 91% and all HPwES installations use a realization rate of 100% because gross savings assumptions are adjusted to reflect evaluated results. [5 9] All other installations have a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are based on prescriptive load shapes from the updated Navigant Massachusetts Demand Impact Model.[6]

Energy Load Shape:

See Appendix 1 – "Lighting".[6]

Impact Factors for Calculating Net Savings:[7]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21A3a009	LED Fixture	ES Products	67%	n/a	n/a	33%
E21A3a010	LED Fixture (Hard to Reach)	ES Products	47%	n/a	n/a	53%

Endnotes:
1: Hours of use (residential) for the ES Products and HTR channel are based off of "New Hampshire ENERGY STAR® Products Program", prepared by Cadmus for the New Hampshire ENERGY STAR Products New Hampshire Evaluation Measurement & Verification Working Group, October 17, 2018. The values reflect the daily weighted average LED hours of use. Cross-sector sales are based upon MA

RLPNC Cross-Sector Sale HOU Update", Prepared by the NMR Group for the Massachusetts Program Administrators (PAs), August 2, 2018. The 2.1 hours per day for ES Products and HTR are calculated as the weighted combination of residential and commercial hours of use: (residential HOU*residential %)+(commercial HOU*commercial %) = (1.75*0.93)+(7.0*0.07). HOU for ES Homes reflects the residential HOU only. Hours of use for the HPwES and HEA are based on program requirements for contractors to only replace fixtures that are used for at least three hours per day.
2: The delta watts are based off of the "MA PAs (2018). 2019-2021 Lighting Worksheet" (https://etrm.anbetrack.com/etrm/api/v1/etrm/documents/5bd06d1d6c50367b3deba017/view?authToken=fe238b4571e888c7558f844a02040d1941948e021564ac20156f12ece790e6a86c8a6c488b1d838694b8d9). Note the delta watts for ES Homes is reduced by 75% to reflect the requirement that 75% of lamps be high-efficacy lamps for new construction (https://www.energycodes.gov/sites/default/files/becu/2015_IECC_residential_requirements.pdf).
3: The direct installation measure life values come from RLPNC 18-5 Home Energy Assessment LED Net-to-Gross Consensus, Prepared by NMR Group, Inc. for the 2019—21 Planning Assumptions: Lighting Hours-of-Use and In-Service Rate, Prepared by NMR Group, Inc. for the Massachusetts Program Administrators (PAs) and Energy Efficiency Advisory Council (EEAC) Consultants, July 23, 2018 (http://ma-eeac.org/wordpress/wp-content/uploads/RLPNC_185_HEALEDNTG_REPORT_23July2018_Final.pdf). These values reflect early replacement baselines, and assume that the replaced bulb, when it burnt out, would have been replaced by an LED at that time. Lighting measures with lost opportunity baselines (e.g., ES Products) add a year to measure life to reflect the different baseline as well as significantly lower hours of use.
4: In-service rates for ES Products and HTR channel, as well as ES Homes, are based on MA assumptions of 100% ISR for fixtures. In-service rates for HPwES and HEA are based on the NH study "Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL," Prepared by Opinion Dynamics Corporation, June 11, 2020. https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NHSaves-HPwES-Evaluation-Report-Final-20200611.pdf
5: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
6: Navigant, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
7: "R1615 Light Emitting Diode (LED) Net-to- Gross Evaluation," Prepared by the NMR Group, Inc. for the Connecticut EEB, August 7, 2017. The 2020 Connecticut net-to-gross values are applied to New Hampshire for 2021 to account for the relatively slower pace of market transformation, due in part to fewer program bulbs per home in New Hampshire (2.5 bulbs per home in 2019) compared to Connecticut (4 bulbs per home in 2019).
8: Table 22. PY2016 Residential Lighting Energy Savings by Utility. Shows evaluated annual net electric energy savings, and evaluated penalties for gas, oil, and propane. Using the values for Eversource, a total calculated heating energy penalty of 341,757,000,000 Btu was assessed on the 150,403,000 kWh of electrical energy savings. **"**New Hampshire ENERGY STAR® Products Program 2016 Evaluation Report", prepared by Cadmus for the New Hampshire ENERGY STAR Products New Hampshire Evaluation Measurement & Verification Working Group, October 17, 2018.
9: Opinion Dynamics, July 29 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

1.34 Lighting – LED Lamp

Measure Code	[To Be Defined in ANB system]
Market	Residential
Program Type	Retrofit/Lost Opportunity
Category	Lighting

Description:

The installation of Light-Emitting Diode (LED) screw-in lamps and linear LEDs. LEDs offer comparable luminosity to incandescent and halogen lamps at significantly less wattage and significantly longer lamp lifetimes.

Baseline Efficiency:

The baseline efficiency case lost opportunity is a combination of an incandescent lamp, halogen lamp, and a compact fluorescent lamp. The baseline efficiency case for retrofit LED lamps is a combination of an incandescent lamp and halogen lamp.

High Efficiency:

The high efficiency case is an ENERGY STAR ® rated LED lamp.

Algorithms for Calculating Primary Energy Impact:

Unit savings are based on the algorithm below. Demand savings are derived from the Navigant Demand Impact Model.

Vendor calculated unit savings are calculated using the following algorithms and assumptions:[1]

$\Delta kWh = ((Watts\_Ineff - Watts\_EE) \times HOU)/1000 \times 365$

$\Delta kW = \Delta kWh \times kW/kWh$

kW/kWh = Average kW reduction per kWh reduction: 0.00025 kW/kWh

Watts_Ineff = Rated watts of inefficient lamps (either removed, through retrofit, or assumed to have been installed in lieu of the program lamps, through lost opportunity)

Watts_EE = Rated watts of efficient lamps installed

365 = Days per year

HOU = Daily hours of use. The hours of use are largely based on recent NH evaluation studies for the ENERGY STAR Products Program and the Home Performance with ENERGY STAR Program, as well as increased hours of operation for ENERGY STAR Products to account for cross-sector sales at retailers (i.e., businesses purchasing program incented lamps). The direct installation delivery strategies (HPwES, HEA) are based on residential hours only but reflect higher hours of use since the programs direct contractors to only replace lamps that are used for at least three hours per day. The following summarizes the key assumptions for daily hours of use:[2]

- Lost opportunity LEDs installed in residential applications: 1.75 hours/day
- Lost opportunity LEDs installed in commercial applications (7% of all lost opportunity lamps): 7 hours/day
- Retrofit HPwES LEDs (all installed in residential applications): 3.0 hours/day
- Retrofit HEA LEDs: (all installed in residential applications): 3.0 hours/day

Delta watts (Watts_Ineff – Watts_EE) are broken out by lamp style and delivery strategy, and reflect a mix of program lamp wattages (for the efficient wattage), removed lamps (for retrofit inefficient lamps), and a blended mix of incandescents, halogens, and CFLs that would have been purchased in absence of the program measure (for lost opportunity inefficient lamps).[3, 11]

Note that the ENERGY STAR Homes values represent a weighted average (based on the distribution of LEDs in NH homes as identified as part of a recent saturation study) of general service lamps, reflectors, and other specialty values.[4] The linear lamp values are based off of a separate research project in MA that specifically examined the characteristics (e.g., incented technologies, rooms with linear lamps) of linear LEDs.[5]

BC Measure ID	Measure Name	Program	Delta Watts	Daily HOU	ΔkWh	ΔkW
E21A3a001	General Service Lamps	ES Products	40	2.1	30.7	0.008
E21A3a004	Reflector	ES Products	43	2.1	33.0	0.008
E21A3a003	Other Specialty	ES Products	35	2.1	26.8	0.007
E21A3a002	Linear	ES Products	17.9	1.6	10.5	0.003
E21A2a044	General Service Lamps	HPwES	32.2	3.0	35.3	0.009
E21A2a047	Reflector	HPwES	46.2	3.0	50.6	0.013
E21A2a046	Other Specialty	HPwES	46.2	3.0	50.6	0.013
E21A2a045	Linear	HPwES	17.9	3.0	19.6	0.005
E21B1a044	General Service Lamps	HEA	Vendor Calculated			
E21B1a047	Reflector	HEA	Vendor Calculated			
E21B1a046	Other Specialty	HEA	Vendor Calculated			
E21B1a045	Linear	HEA	Vendor Calculated			
E21A3a005	General Service Lamps (Hard to Reach)	ES Products	40	2.1	30.7	0.008
E21A3a008	Reflector (Hard to Reach)	ES Products	43	2.1	33.0	0.008
E21A3a007	Other Specialty (Hard to Reach)	ES Products	35	2.1	26.8	0.007
E21A3a006	Linear (Hard to Reach)	ES Products	17.9	1.6	10.5	0.003
E21A1a023	ES Homes Lighting	ES Homes	10.2	1.75	6.5	0.002

Measure Life:

The table below summarizes the measure lives for each of the measures listed above. Note these measure lives have been adjusted to account for the differential in measure life between the inefficient lamps and LEDs (as well as the remaining useful life in the retrofit cases), and the potential for future lighting standards to lead the same sockets reached through the program to have been occupied by an LED in a period shorter than the technical life of the LED.[6]

BC Measure ID	Measure Name	Program	Adjusted Measure Life
E21A3a001	General Service Lamps	ES Products/Drop Ship	3
E21A3a004	Reflector	ES Products/Drop Ship	2
E21A3a003	Other Specialty	ES Products/Drop Ship	3
E21A3a002	Linear	ES Products	10
E21A2a044 E21B1a044	General Service Lamps	HPwES/HEA	2
E21A2a047 E21B1a047	Reflector	HPwES/HEA	2
E21A2a046 E21B1a046	Other Specialty	HPwES/HEA	2
E21A2a045 E21B1a045	Linear	HPwES/HEA	10
E21A3a005	General Service Lamps (Hard to Reach)	ES Products	3
E21A3a008	Reflector (Hard to Reach)	ES Products	2
E21A3a007	Other Specialty (Hard to Reach)	ES Products	3
E21A3a006	Linear (Hard to Reach)	ES Products	10
E21A1a023	ES Homes Lighting	ES Homes	3

Other Resource Impacts:

Based on the 2018 NH Energy Star Products Program Evaluation report, fossil fuel interactive penalties for residential lighting programs are -2,272 Btu/kWh saved.[10]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3a001	General Service Lamps	ES Products	0.86	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a004	Reflector	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a003	Other Specialty	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a002	Linear	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21B1a044	General Service Lamps	HEA	1.00	0.91	n/a	0.91	0.91	0.55	0.85
E21A2a044	General Service Lamps	HPwES	0.99	1.00	n/a	1.00	1.00	0.55	0.85
E21B1a047	Reflector	HEA	1.00	0.91	n/a	0.91	0.91	0.55	0.85
E21A2a047	Reflector	HPwES	0.99	1.00	n/a	1.00	1.00	0.55	0.85
E21B1a046	Other Specialty	HEA	1.00	0.91	n/a	0.91	0.91	0.55	0.85
E21A2a046	Other Specialty	HPwES	0.99	0.96	n/a	0.96	0.96	0.55	0.85
E21B1a045	Linear	HEA	1.00	0.91	n/a	0.91	0.91	0.55	0.85
E21A2a045 E21B1a045	Linear	HPwES	0.99	0.96	n/a	0.96	0.96	0.55	0.85

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A3a005	General Service Lamps (Hard to Reach)	ES Products	0.86	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a008	Reflector (Hard to Reach)	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a007	Other Specialty (Hard to Reach)	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21A3a006	Linear (Hard to Reach)	ES Products	0.89	1.00	n/a	1.00	1.00	0.55	0.85
E21A1a023	ES Homes Lighting	ES Homes	1.00	1.00	n/a	1.00	1.00	0.55	0.85

In-Service Rates:

All HEA installations use an in-service rate of 100% because HEA realization rates account for uninstalled measures[12]. All HPwES installations use an in-service rate of 99%.[4] In-service for all other installations are based on MA evaluations.[7]

Realization Rates:

Based on evaluation results, all HEA installations use a realization rate of 91%.[12] All HPwES installations use a realization rate of 100% because gross savings assumptions are adjusted to reflect evaluated results.[4] All other installations have a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are based on prescriptive loadshapes from the updated Navigant Massachusetts Demand Impact Model.[8]

Energy Load Shape:

See Appendix 1 – “Lighting”.[8]

Impact Factors for Calculating Net Savings:[9]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21A3a001	General Service Lamps	ES Products	77%	n/a	n/a	23%

E21A3a004	Reflector	ES Products	77%	n/a	n/a	23%
E21A3a003	Other Specialty	ES Products	77%	n/a	n/a	23%
E21A3a002	Linear	ES Products	77%	n/a	n/a	23%
E21A3a005	General Service Lamps (Hard to Reach)	ES Products	57%	n/a	n/a	43%
E21A3a008	Reflector (Hard to Reach)	ES Products	57%	n/a	n/a	43%
E21A3a007	Other Specialty (Hard to Reach)	ES Products	57%	n/a	n/a	43%
E21A3a006	Linear (Hard to Reach)	ES Products	57%	n/a	n/a	43%

Endnotes:
1: Note that interactive effects require modeling HVAC end-use consumption based on home characteristics and equipment (e.g., cooling, heating fuel) saturation assumptions. The data and models were not available for New Hampshire, so are not included in the TRM.
2: Hours of use (residential) for the ES Products and HTR channel are based off of "New Hampshire ENERGY STAR® Products Program", prepared by Cadmus for the New Hampshire ENERGY STAR Products New Hampshire Evaluation Measurement & Verification Working Group, October 17, 2018. The values reflect the daily weighted average LED hours of use. Cross-sector sales are based upon MA RLPNC Cross-Sector Sale HOU Update", Prepared by the NMR Group for the Massachusetts Program Administrators (PAs), August 2, 2018. The 2.1 hours per day for ES Products and HTR channel are calculated as the weighted combination of residential and commercial hours of use: (residential HOU*residential %)+(commercial HOU*commercial %) = (1.75*0.93)+(7.0*0.07). HOU for ES Homes reflects the residential HOU only. Hours of use for the HPwES and HEA are based on program requirements for contractors to only replace fixtures that are used for at least three hours per day.
3: NMR, 2020. Delta Watt Update (MA19R09-E). Delta watts for ES Products and HTR are based on both historical lamps sales in Massachusetts and the most recently available market adoption model (for PY2021). Note that Massachusetts data were used because the New Hampshire ENERGY STAR Product evaluation had not stratified the program data or forecasted baseline wattage by style at the time of this TRM. The delta watts for ES Homes is reduced by 75% to reflect the requirement that 75% of lamps be high-efficacy lamps for new construction (https://www.energycodes.gov/sites/default/files/becu/2015_IECC_residential_requirements.pdf).
4: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.
5: RLPNC 18-7: TLED Product Impact Factor Estimation, Memo from NMR Group, Inc. to the Massachusetts Program Administrators, August 3, 2018.
6: The direct installation measure life values come from RLPNC 18-5 Home Energy Assessment LED Net-to-Gross Consensus, Prepared by NMR Group, Inc. for the 2019—21 Planning Assumptions: Lighting Hours-of-Use and In-Service Rate, Prepared by NMR Group, Inc. for the Massachusetts Program Administrators (PAs) and Energy Efficiency Advisory Council (EEAC) Consultants, July 23, 2018 (http://ma-eeac.org/wordpress/wp-content/uploads/RLPNC_185_HEALEDNTG_REPORT_23July2018_Final.pdf). These values reflect early replacement baselines, and assume that the replaced bulb, when it burnt out, would have been replaced by an LED at that time. Lighting measures with lost opportunity baselines (e.g., ES Products) add a year to measure life to reflect the different baseline as well as significantly lower hours of use.
7: In-service rates for ES Products and HTR channel are based on the MA study "RLPNC 179: 2019—21 Planning Assumptions: Lighting Hours-of-Use and In-Service Rate," Prepared by the NMR Group, Inc.

for the Massachusetts Program Administrators, July 13, 2018. Note the ISR is adjusted downward for lamps that are assumed to never be installed but does account (through discounted values) for lamps that are not immediately installed but are likely to be installed in the future. The ISR for Drop Ship is estimated based on program experience with lighting kits and will be evaluated.
8: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
9: "R1615 Light Emitting Diode (LED) Net-to- Gross Evaluation," Prepared by the NMR Group, Inc. for the Connecticut EEB, August 7, 2017. The 2020 Connecticut net-to-gross values are applied to New Hampshire for 2021 to account for the relatively slower pace of market transformation, due in part to fewer program bulbs per home in New Hampshire (2.5 bulbs per home in 2019) compared to Connecticut (4 bulbs per home in 2019).
10: Table 22. PY2016 Residential Lighting Energy Savings by Utility. Shows evaluated annual net electric energy savings, and evaluated penalties for gas, oil, and propane. Using the values for Eversource, a total calculated heating energy penalty of 341,757,000,000 Btu was assessed on the 150,403,000 kWh of electrical energy savings. "New Hampshire ENERGY STAR® Products Program 2016 Evaluation Report", prepared by Cadmus for the New Hampshire ENERGY STAR Products New Hampshire Evaluation Measurement & Verification Working Group, October 17, 2018.
11: Delta watts for HPwES are based on NH study "Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL," Prepared by Opinion Dynamics Corporation, June 11, 2020. https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NHSaves-HPwES-Evaluation-Report-Final-20200611.pdf
12: Opinion Dynamics, July 29, 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

Revision Number	Issue Date	Description
58	1/14/2022	Removed drop ship measures which are not being offered.

1.35 Thermostat – Wi-Fi Communicating

Measure Code	TBD
Market	Residential
Program Type	Retrofit
Category	HVAC

Description:

A communicating Wi-Fi enabled thermostat which allows remote set point adjustment and control via remote application. System requires an outdoor air temperature algorithm in the control logic to operate heating and cooling systems.

Baseline Efficiency:

The baseline efficiency case is an HVAC system with either a manual or a programmable thermostat.

High Efficiency:

The high efficiency case is an HVAC system that has a Wi-Fi thermostat installed.

Algorithms for Calculating Primary Energy Impact: [4]

Unit savings are deemed based primarily on impact evaluation results.[4] ES Products savings are deemed based on statewide data on saturation of residential cooling equipment and heating fuel types.[3] For fuels that were not included in the impact evaluation (i.e. kerosene and wood pellets), unit savings are instead based on secondary research recommendations.[1]
Direct install thermostats that control both heating and cooling systems should claim savings using the Cooling measure in the last line of the table below in addition to the relevant heating savings measure line.

The utilities are not claiming any peak kW demand reductions until impact evaluation results are available, as savings are driven by runtime reductions rather than demand reductions.

BC Measure ID	Measure Name	Energy Type	Program	ΔkWh	ΔkW	ΔMMbtu
E21B1b015 E21A2b015	Wi-Fi Thermostat, Electric Heating	Electricity	HEA HPwES	419.0	0	n/a
E21B1b016 G21B1b004 E21A2b016 G21A2b004	Wi-Fi Thermostat, Gas	NG - Res Heating	HEA HPwES	46.0	n/a	5.80
E21B1b017 E21A2b017	Wi-Fi Thermostat, Kerosene	Kerosene	HEA HPwES	n/a	n/a	3.10

E21B1b018 E21A2b018	Wi-Fi Thermostat, Oil	Fuel Oil - Residential Distillate	HEA HPwES	n/a	n/a	5.90
E21B1b019 E21A2b019	Wi-Fi Thermostat, Propane	Propane	HEA HPwES	n/a	n/a	5.80
E21B1b020 E21A2b020	Wi-Fi Thermostat, Wood Pellets	Pellet Wood	HEA HPwES	n/a	n/a	3.10
E21A3b026	Wi-Fi Thermostat (Heating & Cooling)	Fuel Blind	ES Products	46.00	n/a	4.92
G21A3b019	WiFi Thermostat (Heating Only)	NG - Res Heating	ES Products	n/a	n/a	5.80
G21A3b020	Wi-Fi Thermostat (Heating & Cooling)	NG - Res Heating	ES Products	46.0	n/a	5.80

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

No other impacts are reported.

Impact Factors for Calculating Adjusted Gross Savings: [1,3,4]

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_{E}	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b015	Wi-Fi Thermostat, Electric	Electricity	HEA	1.00	0.91	n/a	0.91	0.91	n/a	n/a
E21A2b015	Wi-Fi Thermostat, Electric	Electricity	HPwES	0.99	0.96	n/a	0.96	0.96	n/a	n/a

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b016 G21B1b004	Wi-Fi Thermostat, Gas	NG - Res Heating	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b016 G21A2b004	Wi-Fi Thermostat, Gas	NG - Res Heating	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21B1b017	Wi-Fi Thermostat, Kerosene	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b017	Wi-Fi Thermostat, Kerosene	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1b018	Wi-Fi Thermostat, Oil	Fuel Oil - Residential Distillate	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b018	Wi-Fi Thermostat, Oil	Fuel Oil - Residential Distillate	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1b019	Wi-Fi Thermostat, Propane	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b019	Wi-Fi Thermostat, Propane	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21B1b020	Wi-Fi Thermostat, Wood Pellets	Pellet Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b020	Wi-Fi Thermostat, Wood Pellets	Pellet Wood	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A3b026 G21A3b019 G21A3b020	Wi-Fi Thermostat (Heating Only; Cooling Only; Heating & Cooling)	NG- Res Heating; Fuel Blind	ES Products	1.00	1.00	1.04	n/a	n/a	n/a	n/a

In-Service Rates:

All HEA installations have a 100% in-service-rate and all HPwES installations have a 99% in-service rate based on evaluation results.[5,6] All ES Products installations use a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All HEA installations have a 91% realization rate and all HPwES installations have a 100% realization rate for electric, 114% for oil, propane and wood, and 104% for gas based on evaluation results.[5,6] All ES Products installations use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

The utilities are not claiming any peak kW demand reductions until impact evaluation results are available, as savings are driven by runtime reductions rather than demand reductions.

Energy Load Shape:

See Appendix 1 "Weighted HVAC- All Homes"

Endnotes:

1: Navigant Consulting, September 2018. Wi-Fi Thermostat Impact Evaluation--Secondary Research Study Memo. http://ma-eeac.org/wordpress/wp-content/uploads/Wi-Fi-Thermostat-Impact-Evaluation-Secondary-Literature-Study_FINAL.pdf

2: Environmental Protection Agency, 2010. Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat. Assumed to have the same lifetime as a regular programmable thermostat

3: Itron 2020. New Hampshire Residential Baseline Study. Prepared for New Hampshire Evaluation, Measurement and Verification Working Group. Worksheet based on this analysis embedded here:

WiFi tStat Worksheet, 2021.xlsx

4: Navigant Consulting, August 2018. Home Energy Services (HES) Impact Evaluation, Table 5-13. https://ma-eeac.org/wp-content/uploads/RES34_HES-Impact-Evaluation-Report-with-ES_FINAL_29AUG2018.pdf

5: Opinion Dynamics, July 29, 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.

6: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.

1.36 Thermostat – Programmable

Measure Code	
Market	Residential
Program Type	Retrofit
Category	HVAC

Description:

Installation of a programmable thermostat, which gives the ability to adjust heating or air-conditioning operating times according to a pre-set schedule.

Baseline Efficiency:

The baseline efficiency case is an HVAC system without a programmable thermostat: either a manual thermostat or no thermostat.

High Efficiency:

The high efficiency case is an HVAC system that has a programmable thermostat installed.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on evaluation results.[1]

BC Measure ID	Measure Name	Energy Type	Program	ΔkWh	ΔkW	ΔMMbtu
E21B1b009	Programmable Thermostat, Electric Heat	Electricity	HEA	251.0	n/a	n/a
E21B1b010 G21B1b003	Programmable Thermostat, Gas	NG - Res Heating	HEA	27	0.04	3.50
E21B1b011	Programmable Thermostat, Kerosene	Kerosene	HEA	n/a	n/a	3.50
E21B1b012	Programmable Thermostat, Oil	Fuel Oil - Residential Distillate	HEA	n/a	n/a	3.50
E21B1b013	Programmable Thermostat, Propane	Propane	HEA	n/a	n/a	3.50
E21B1b014	Programmable Thermostat, Wood Pellets	Pellet Wood	HEA	n/a	n/a	3.50

E21A2b009	Programmable Thermostat, Electric	Electricity	HPwES	251.0	n/a	n/a
E21A2b010 G21A2b003	Programmable Thermostat, Gas	NG - Res Heating	HPwES	27	n/a	3.50
E21A2b011	Programmable Thermostat, Kerosene	Kerosene	HPwES	n/a	n/a	3.50
E21A2b012	Programmable Thermostat, Oil	Fuel Oil - Residential Distillate	HPwES	n/a	n/a	3.50
E21A2b013	Programmable Thermostat, Propane	Propane	HPwES	n/a	n/a	3.50
E21A2b014	Programmable Thermostat, Wood Pellets	Pellet Wood	HPwES	n/a	n/a	3.50
TBD	Programmable Thermostat, AC only	Electricity	TBD	27.0	n/a	n/a
G21A3b011	Programmable Thermostat, Gas	Gas	ES Products	27.0	0.04	3.5

Thermostats that control both heating and central cooling may claim savings for both cooling (27.0 kWh/yr) and heating impacts (by fuel).

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

No other resource impacts are included.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21B1b009	Programmable Thermostat, Electric	Electricity	HEA	1.00	0.91	0.00	0.91	0.91	0.00	1.00

E21B1b010 G21B1b003	Programmable Thermostat, Gas	NG - Res Heating	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1b011	Programmable Thermostat, Kerosene	Kerosene	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1b012	Programmable Thermostat, Oil	Fuel Oil - Residential Distillate	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1b013	Programmable Thermostat, Propane	Propane	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21B1b014	Programmable Thermostat, Wood Pellets	Pellet Wood	HEA	1.00	n/a	0.91	n/a	n/a	n/a	n/a
E21A2b009	Programmable Thermostat, Electric	Electricity	HPwES	0.99	0.96	n/a	0.96	0.96	0.00	1.00
E21A2b010	Programmable Thermostat, Gas	NG - Res Heating	HPwES	0.99	n/a	1.04	n/a	n/a	n/a	n/a
E21A2b011	Programmable Thermostat, Kerosene	Kerosene	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2b012	Programmable Thermostat, Oil	Fuel Oil - Residential Distillate	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2b013	Programmable Thermostat, Propane	Propane	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
E21A2b014	Programmable Thermostat, Wood Pellets	Pellet Wood	HPwES	0.99	n/a	1.14	n/a	n/a	n/a	n/a
TBD	Programmable Thermostat, AC only	Electricity	TBD	1.00	1.00	1.14	1.00	1.00	1.00	0.00

Programmable thermostats that control both cooling and heating equipment should claim both the 27 kWh of electric energy savings associated with the cooling equipment at the impact factors listed above and any heating savings.

<u>In-Service Rates:</u>

All HEA installations have a 100% in-service rate and all HPwES installations have a 99% in-service rate based on evaluation results.[4] [5]

Realization Rates:

All HEA installations have a 91% realization rate and all HPwES installations have a 100% realization rate based on evaluation results.[4 5]

Coincidence Factors:

Summer and winter coincidence factors are estimated using demand allocation methodology described the Navigant Demand Impact Model prepared for MA Program Administrators.[3]

Energy Load Shape:

See Appendix 1 "Weighted HVAC- All Homes"

Endnotes:
1: Navigant Consulting, August 2018. Home Energy Services (HES) Impact Evaluation. https://ma-eeac.org/wp-content/uploads/RES34_HES-Impact-Evaluation-Report-with-ES_FINAL_29AUG2018.pdf**2:** Environmental Protection Agency, 2010. Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat.
3: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
4: Opinion Dynamics, July 29, 2020, New Hampshire Utilities, Home Energy Assistance Program Evaluation Report, 2016-2017 – FINAL.
5: Opinion Dynamics, June 11, 2020, Home Performance with Energy Star Program Evaluation Report 2016-2017 – FINAL.

Revision Number	Issue Date	Description
38	1/14/2022	Corrected E21A2b010 G21A2b003 to reflect kWh savings.
39	1/14/2022	Corrected realization rate verbiage to reflect the correct data shown in the table.

1.37 Whole Home – New Construction

Measure Code	RES-WH-NEW
Market	Residential
Program Type	Lost Opportunity
Category	Whole Home

Description:

The Program Administrators currently use vendor calculated energy savings using a RESNET accredited Rating Software Tool (REM/Rate) where a user inputs a detailed set of technical data about a project, comparing as-built projected energy consumption to that of a Baseline Home. This process is used to calculate electric and fossil fuel energy savings due to heating, cooling, and water heating for all homes.[1]

Baseline Efficiency:

The Baseline Home is based on a User Defined Reference Home (UDRH), which was updated in 2019 to reflect the IECC 2015 code, with amendments as adopted by the state of NH.[2, 3] UDRH heating system efficiencies and air infiltration rates remain more stringent than code to reflect the results of the 2017 NH Energy Star Homes evaluation.[4]

High Efficiency:

The high-efficiency case is represented by the specific energy characteristics of each "as-built" home completed through the program.

Algorithms for Calculating Primary Energy Impact:

Unit savings are custom calculated for each home for heating, cooling, and water heating end uses. Demand savings are derived from the Navigant Demand Impact Model. As noted below, because the values are custom generated on a site-by-site basis, they are not shown in the table below.

BC Measure ID	Measure Name	Program
E21A1a001 E21A1a012 G21A1a001 G21A1a002	Cooling, Electric Cooling, Electric SF Cooling, Electric, MF	ES Homes
E21A1a002 E21A1a013	Heating, Electric	ES Homes
E21A1a003 E21A1a014 G21A1a002	Heating, Gas Heating, Gas,SF Heating, Gas, MF	ES Homes

G21A1a005		
E21A1a004 E21A1a015	Heating, Oil	ES Homes
E21A1a005 E21A1a016	Heating, Propane	ES Homes
E21A1a006 E21A1a017	Heating, Wood Pellets	ES Homes
E21A1a007 E21A1a018	Hot Water, Electric	ES Homes
E21A1a008 E21A1a019 G21A1a003 G21A1a006	Hot Water, Gas Hot Water, Gas, SF Hot Water, Gas,MF	ES Homes
E21A1a009 E21A1a020	Hot Water, Oil	ES Homes
E21A1a010 E21A1a021	Hot Water, Propane	ES Homes
E21A1a011 E21A1a022	Hot Water, Wood Pellets	ES Homes

Measure Life:

The measure life is shown below and varies by end use.[5]

BC Measure ID	Measure Name	Program	EUL
E21A1a002 E21A1a013 E21A1a003 E21A1a014 E21A1a004 E21A1a015 E21A1a005 E21A1a016 E21A1a006 E21A1a017	Heating	ES Homes	25
E21A1a001 E21A1a012	Cooling	ES Homes	25
E21A1a007 E21A1a018 E21A1a008 E21A1a019 E21A1a009 E21A1a020 E21A1a010 E21A1a021 E21A1a011 E21A1a022	Water Heating	ES Homes	15

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A1a001 E21A1a012	Cooling, Electric	ES Homes	1.00	1.00	1.00	1.00	1.00	0.35	0.00
E21A1a002 E21A1a013	Heating, Electric	ES Homes	1.00	1.00	1.00	1.00	1.00	0.00	0.43
E21A1a003 E21A1a014	Heating, Gas	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a004 E21A1a015	Heating, Oil	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a005 E21A1a016	Heating, Propane	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a006 E21A1a017	Heating, Wood Pellets	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A1a007 E21A1a018	Hot Water, Electric	ES Homes	1.00	1.00	1.00	1.00	1.00	0.31	0.81
E21A1a008 E21A1a019	Hot Water, Gas	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a009 E21A1a020	Hot Water, Oil	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a010 E21A1a021	Hot Water, Propane	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E21A1a011 E21A1a022	Hot Water, Wood Pellets	ES Homes	1.00	1.00	1.00	1.00	1.00	1.00	1.00

In-Service Rates:

All installations have 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All energy realization rates are 100% because energy and demand savings are custom calculated based on project specific details.

Coincidence Factors:

Coincidence factors for electric end uses are based on prescriptive load shapes from the updated Navigant Demand Impact Model for Massachusetts.[6]
Coincidence factors for non-electric end uses are set to 100% as no electrical energy impacts are expected.

Energy Load Shape

See Appendix 1.

Endnotes:

1: Note that there are also prescriptive rebates for appliances, including clothes washers, clothes dryers, and refrigerators, as well as lighting, which are covered in other sections of the TRM.
2: See "ESHOME UDRH update 02-23-2018, Revised 5-17-2019.docx"
3: Note the UDRH represents both single family and multifamily homes, and all measures (cooling heating, and hot water) are present in both single family and multifamily homes.
4: Energy and Resource Solutions, December 7, 2018. New Hampshire ENERGY STAR Homes Program Impact Evaluation. Prepared for the NH Program Administrators. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/NH_ESHomes_Report_Final_v4-2017.pdf
5: MA Technical Reference Manual 2019 Plan-Year Report Version, Page 244, "Chapter 1.60: Whole Home New Construction" section, accessed on February 14, 2020, and GDS Associates Inc. Measure Life Report, Residential and Commercial Industrial Lighting and HVAC Measures, Jun. 2007.
6: Navigant Consulting, 2018. RES 1 Demand Impact Model Update. http://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision History

Revision Number	Issue Date	Description

40	1/14/2022	Fixed broken link in references

1.38 Whole Home – Energy Report

Measure Code	
Market	Residential
Program Type	Custom
Category	Behavioral

Description:

Residential home energy report ("HER") programs levereage behavior science to influence customers' energy use practices. The program strategy involves sending customer-specific energy use reports to a sample of electric and / or natural gas customers. The implementation vendor calculates savings results based on statistical analysis of the differences in energy usage for the treatment group when compared to the energy usage of a control group.

Baseline Efficiency:

The baseline efficiency case is a control-group customer who does not receive home energy reports.

High Efficiency:

The high efficiency case is a customer who receives periodic mailed and/or emails home energy reports tailored and has access to a web-based dashboard that includes tailored messaging regarding ways of reducing energy use.

Algorithms for Calculating Primary Energy Impact:

Unit savings for Home Energy Reports are based on calculations from vendor results.

A lagged-dependent variable (LDV) model (sometimes also referred to as a post-period regression with pre-period controls) utilizes a panel data set (a cross-sectional time-series) to estimate energy savings from a randomized control trial (RCT) using pre-treatment (lagged) energy consumption value(s) as an independent control.

$$ADU_{k,t} = \alpha + \beta_1 treatment_k + \sum_j \beta_{2j} Month_t + \sum_i \beta_{3i} ADUlag_{k,t,i} + \varepsilon_{k,t}$$

Where:

- $ADU_{k,t}$ is average daily consumption of kWh by household *k* in month *t*,
- α is the model intercept,
- $treatment_k$ is a binary variable with a value of 0 if household *k* is assigned to the control group and 1 if assigned to the treatment group,
- $Month_j$ is a binary variable with a value of 1 when *t*=*j*, and is 0 otherwise,
- $ADUlag_{k,t,i}$ is a vector of *i* baseline usage control variables. An evaluator may choose the form of these control values, as pre-treatment data availability may allow. A suggested formulation for this vector is the following three (*i*=3) LDV terms:

- $avg\_preusage_k$ is the average daily usage across household k's available pre-treatment meter reads for the year prior to the start of treatment,
- $avg\_preusage\_winter_k$ is the average daily usage over the months of December through March across household k's available pre-treatment meter reads for the year prior to the start of treatment and,
- $avg\_preusage\_winter_k$ is the average daily usage over the months of June through September across household k's available pre-treatment meter reads for the year prior to the start of treatment.

A simpler, alternative, formulation of this $ADUlag_{k,t,i}$ term can be a single (i=1) LDV representing household k's average daily energy use in the same calendar month as t in year immediately preceding the program.

- $\varepsilon_{k,t}$ is the cluster-robust idiosyncratic error term for household k in month t.

The coefficient β_1 is the coefficient of interest; it is the estimate of average daily energy savings for a household in the treatment group.

Measure Life:

The measure life for Home Energy Reports is 1 year[1]. As a behavioral measure, the intervention of regularly receiving a Home Energy Report is required to claim savings.

BC Measure ID	Measure Name	Program	Measure Life
E21A4a001 G21A4a001	Residential Whole Home Energy Report	Residential Behavior	1

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21A4a001	Residential Whole Home Energy Report	Residential Behavior	1.00	1.00	NA	1.00	1.00	0.547	0.848
G21A4a001	Residential Whole Home Energy Report	Residential Behavior	1.00	NA	1.00	NA	NA	NA	NA

<u>In-Service Rates:</u>

All installations have 100% in-service-rates since reports are sent out regularly to participants.[1]

<u>Realization Rates:</u>

Realization rates from Navigant's 2016 evaluation of Eversource New Hampshire Home Energy Report pilot program found that the realization rate for the normative behavior program design was 99.9%.[1]

Coincidence Factors:

Summer and winter coincidence factors are based on a residential lighting loadshape.[2]

Energy Load Shape:

See Appendix 1.

Endnotes:
1: Navigant Consulting (2016). Home Energy Report Pilot Program Evaluation Final Report, Feb 2014-Feb 2015. Prepared for Eversource New Hampshire.
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. https://ma-eeac.org/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

Revision History

Revision Number	Issue Date	Description
41	1/14/2022	Fixed broken link in references

2. Commercial and Industrial

2.0 C&I Active Demand Response

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Custom
Category	Active Demand Response

Description:

Active Demand Reduction includes C&I Load Curtailment Targeted Dispatch and Storage Daily Dispatch Performance.

The Load Curtailment offering is technology agnostic and provides an incentive for verifiable shedding of load in response to a signal or communication from the Program Administrators coinciding with system peak conditions. Large C&I customers that are subject to demand charges and/or direct capacity charges (determined by ICAP tags) with the ability to control lighting, HVAC, and/or process loads, can use this demand reduction performance offering to generate revenue by altering their operations a few times per year. The offering focuses on reducing demand during summer peak events typically targeting fewer than twenty hours per summer.

The C&I Storage Performance offering provides performance incentives for C&I storage performance. Since storage does not impact customer comfort or operations, storage resources are expected to be available for daily dispatch to maximize their value.

Baseline Efficiency:

Baseline conditions will be determined based on technology.

For Load Curtailment, baseline conditions are based on an adjustment settlement baseline with symmetric, additive adjustment. The symmetrically adjusted settlement baseline is developed based on a pool of the most recent 10 non-holiday weekdays. The baseline shape consists of average load per interval across the eligible days. The baseline is adjusted based on the difference between baseline and facility load in the second hour prior to the event (the baseline adjustment period), and the adjustment can be either to increase or decrease the estimated load reduction (i.e., symmetric adjustment). This adjustment accounts for weather-related and other differences of load magnitude.[1]

For Storage, demand reduction is calculated based on battery load. A baseline value is not directly calculated for storage, instead, the counterfactual is the actual facility load without the battery, which is derived based on the facility load with the battery and the battery load.[2]

High Efficiency:

Active Demand Reduction does not directly increase efficiency. Load curtailment does reduce power consumption by curtailing use, but does not inherently reduce energy consumption.

Storage increases energy consumption due to round trip efficiency losses. Battery round trip efficiency losses are calculated on a per-project basis. For reference, evaluation results for daily dispatch storage reflect an impact of 240 kWh per year per kW of nameplate battery discharge capacity.[2]

Algorithms for Calculating Primary Energy Impact:

The Active Demand Reduction measure generates site-specific vendor-reported demand savings, which are validated by evaluation. Savings estimates for these projects are calculated using engineering analysis with project-specific details.

Measure Life:

As all C&I active demand response measures are based on Program Administrators calling demand reduction events each year, the deemed measure life is one year.

BC Measure ID	Measure Name	Program	Measure Life
E21C5a001	Load Curtailment Targeted Dispatch P4P Summer	C&I Active Demand Response	1
E21C5a002	Storage Daily Dispatch P4P (savings) Summer	C&I Active Demand Response	1
E21C5a003	Storage Daily Dispatch P4P (consumption) Summer	C&I Active Demand Response	1

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C5a001	Load Curtailment Targeted Dispatch P4P Summer	C&I Active Demand Response	1.00	0.981	1.00	0.981	1.00	1.00	0.00
E21C5a002	Storage Daily Dispatch P4P (savings) Summer	C&I Active Demand Response	1.00	1.04	1.00	1.04	1.00	1.00	0.00
E21C5a003	Storage Daily Dispatch P4P (consumption) Summer	C&I Active Demand Response	1.00	1.04	1.00	1.04	1.00	1.00	0.00

<u>In-Service Rates:</u>

In-service rates for commercial and industrial active demand response are assumed to be 100% by default, as measured performance in the ADR program is required to claim savings.

Realization Rates:

Electrical energy realization rates for this measure are assumed to be equal to summer peak demand realization rates.
Summer peak realization rates for interruptible load are based on a program evaluation of the 2019 summer demand reduction period for New Hampshire.[1] These realization rates are based on the overall program savings, rather than individual measure savings, and represent the retrospective realization rate (i.e. the evaluated symmetric savings estimate divided by the reported asymmetric savings estimate). For daily and targeted storage dispatch programs, summer peak realization rates are based on an evaluation of Eversource battery storage demonstration projects.[2]

Coincidence Factors:

Coincidence factors for this measure are assumed to be 100%, as the scaling factor accounts for the coincidence of program events with the system peak. The programs are not claiming winter peak impacts due to the fact that the ISO-NE system is summer peaking.

Scaling Factors:

A scaling factor is used to account for the fact that the benefits of an active demand response resource depend on how often it performs. The greater the frequency of demand response events, the more that the active demand resource reduces the installed capacity requirement, and therefore the greater its value. For planning the utilities use a scaling factor of 10% for load curtailment measures and 100% for daily dispatch measures, reflecting the AESC 2018 review of sensitivity analyses run by PJM load forecasters.[3] For reporting utilities will use scaling factor values based on the most recent evaluation timing of events that are called in 2021.

Energy Load Shape:

As commercial active demand response events are called on the day preceding the event, the most appropriate load shape to use is a symmetric load based on the 10 baseline day load shape at the same facility.[1]

Endnotes:
1: ERS (2020). Cross-State C&I Active Demand Reduction Initiative Summer 2019 Evaluation Report. Prepared for Eversource, National Grid, and Unitil (MA, CT, and NH). https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/Cross-State-CI-DR-S19-Evaluation-Report_04-15-2020.pdf

2: ERS (2020). Daily Dispatch Battery Project Evaluation Report. Prepared for Eversource. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee488776996f264267df7b6/view?authToken=8a34f8598773992325038987ea62e83319d208f835e892092c491823f78722e7a92604e473dc75021eb90f821f219b8cbc0ddafaae207ed1924f97faecb70d5eaf3e5372d04fb6

3: Avoided Energy Supply Components in New England: 2018 Report, page 105. https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf

2.1 Building Envelope – Air Sealing and Insulation

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	**Building Shell**

Description:

Air Sealing: Air sealing will decrease the infiltration of outside air through cracks and leaks in the building.

Insulation: The installation of high efficiency insulation in an existing structure.

Air sealing and insulation are offered through the Municipal Energy Solutions program and apply to municipal buildings.

Baseline Efficiency:

Air Sealing: The baseline efficiency case is the existing building before the air sealing measure is implemented. The baseline building is characterized by the existing air changes per hour (ACHPRE) for multi-family facilities, which is measured prior to the implementation of the air sealing measure.

Insulation: The baseline efficiency case is characterized by the total R-value of the existing attic, basement, or sidewall (Rexist). This is calculated as the R-value of the existing insulation, estimated by the program contractor, plus the R-value of the ceiling, floor, or wall (for all projects: RCEILING = 3.36; RFLOOR = 6.16; RWALL = 6.65).

High Efficiency:

Air Sealing: The baseline efficiency case is the existing building after the air sealing measure is implemented. The high efficiency building is characterized by the new air changes per hour (ACHPOST) for multi-family facilities, which is measured after the air sealing measure is implemented.

Insulation: The high efficiency case is characterized by the total R-value of the attic after the installation of additional attic, basement, or sidewall insulation. This is calculated as the sum of the existing R-value (Rexisit) plus the R-value of the added insulation.

Algorithms for Calculating Primary Energy Impact:

Air Sealing:

Unit savings are calculated using the following algorithms and assumptions:

kWh = (Vol x ACH x 0.018 x HDD x 24/ ηheating) / 3,413
MMBtu = (Vol x ACH x 0.018 x HDD x 24/ ηheating) / 1,000,000
kW = kWh x kW/kWh

Where:
Vol = [ft^3] This is the air volume of the treated space, calculated from the dimensions of the space, which could include the number of floors, the floor area per floor, and the floor-to-ceiling height, or the dwelling floor area and number of dwellings. The treated space can be the entire building including the common areas, or just the individual dwelling units. (Auditor Input)
Δ ACH = [ºF-day] Infiltration reduction in Air Changes per Hour, natural infiltration basis. This will typically be a default value, but the source of the assumption should be transparent and traceable, or it could come from a blower door test. (Stipulated Value or Blower Door Test)
HDD60 = Heating degree-days with temperature base of 60 degrees.[1]
ηheating = [AFUE, COP, thermal efficiency (%)] Efficiency of the heating system, as determined on site (Auditor Input)
24 = Conversion factor: 24 hours per day
0.018 = [Btu / ft^3- ºF] Air heat capacity: The specific heat of air (0.24 Btu / ºF.lb) times the density of air (0.075 lb / ft_3)
1,000,000 = Conversion factor: 1,000,000 Btu per MMBtu
3,413 = Conversion factor: 3,413 Btu / kWh
kW / kWh = Average kW reduction per kWh reduction: 0.00073 kW / kWh [2]

Insulation:
Unit savings are calculated using the following algorithms and assumptions:
$MMBtu_{annual} = ((1/R_{exist} - 1/R_{new}) * HDD * 24 * Area)/1000000 * \eta_{heat}$
$kWh_{annual} = MMBtu_{annual} * 293.1$
$kW = kWh_{annual} * kW/kWh_{heating}$

Where,
R_{exist} = Existing effective R-value (R-ExistingInsulation + R-Assembly),ft2-°F/Btuh
R_{new} = New total effective R-value (R-ProposedMeasure + R-ExistingInsulation+ R-Assembly), ft2-°F/Btuh
Area = Square footage of insulated area
η_{heat} = Efficiency of the heating system (AFUE or COP)
293.1 = Conversion constant (1MMBtu = 293.1 kWh)
24 = Conversion for hours per day
HDD = Heating Degree Days; dependent on location
1,000,000 = Conversion from Btu to MMBtu kW/kWh heating = Average annual kW reduction per kWh reduction [2]

Measure	kW/kWh Factor
Insulation (Electric)	0.00073
Insulation (Gas, Oil, Other FF)	0.00076
Insulation, Central AC in Electrically Heated Unit	0.00059

Measure Life:

The measure life is shown in the table below.[3]

BC Measure ID	Measure Name	Program	Measure Life
E21C3a015 E21C3a016 E21C3a017 E21C3a018 E21C3d017 E21C3d018 E21C3d019 E21C3d020	Air Sealing	Municipal Retrofit Municipal Direct Install	15
E21C3a051 E21C3a052 E21C3a053 E21C3a054 E21C3d051 E21C3d052 E21C3d053 E21C3d054	Insulation	Municipal Retrofit Municipal Direct Install	25
G21C1a017 G21C2a017	Air Sealing	Large C&I Retrofit Small C&I Retrofit	15
G21C1a018 G21C2a018	Insulation	Large C&I Retrofit Small C&I Retrofit	25

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[2]

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3a015 E21C3d017	Air Sealing	Electric	Muni Retro Muni DI	1.00	1.00	n/a	n/a	n/a	0.00	0.43
E21C3a016 E21C3d018	Air Sealing	Gas	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a017 E21C3d019	Air Sealing	Oil	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a018 E21C3d020	Air Sealing	Propane	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a051 E21C3d051	Insulation	Electric	Muni Retro Muni DI	1.00	1.00	n/a	n/a	n/a	0.34	0.17

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3a052 E21C3d052	Insulation	Gas	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a053 E21C3d053	Insulation	Oil	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a054 E21C3d054	Insulation	Propane	Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1a017 G21C2a017	Air Sealing	Gas	Large C&I Retrofit Small C&I Retrofit	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1a018 G21C2a018	Insulation	Gas	Large C&I Retrofit Small C&I Retrofit	1.00	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Summer and winter coincidence factors for insulation are estimated using demand allocation methodology described in the Demand Impact Model.
A winter coincidence factor of 43% is utilized for air sealing.[2]

Energy Load Shape:

For electric air sealing and insulation, see Appendix 1 C&I Load Shapes "Hardwired Electric Heat"
For non-electric air sealing, see Appendix 1 C&I Load Shapes "Non-Electric Measures"
For non- electric insulation, see Appendix 1 C&I Load Shapes "Central Air Conditioner/ Heat Pump (Cooling)

Endnotes:
1: The HDD should be calculated based on the TMY3 weather data of the nearest weather station. https://www7.ncdc.noaa.gov/CDO/cdoselect.cmd?datasetabbv=GSOD&countryabbv=&georegionabbv
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
3: Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, June 2007. https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf

2.2 Compressed Air – Air Compressor

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Compressed Air

Description:

Covers the installation of oil flooded, rotary screw compressors with Variable Speed Drive or Variable Displacement capacity control with properly sized air receiver. Efficient air compressors use various control schemes to improve compression efficiencies at partial loads.

Baseline Efficiency:

The baseline efficiency case is a typical load/unload compressor.

High Efficiency:

The high efficiency case is an oil-flooded, rotary screw compressor with Variable Speed Drive or Variable Displacement capacity control with a properly sized air receiver. Air receivers are designed to provide a supply buffer to meet short-term demand spikes which can exceed the compressor capacity. Installing a larger receiver tank to meet occasional peak demands can allow for the use of a smaller compressor.

Algorithms for Calculating Primary Energy Impact:

Δ kWh = (HP COMPRESSOR) x (Save) x (Hours)
Δ kW = (HP COMPRESSOR) x (Save)
Where:
HP COMPRESSOR = Nominal rated horsepower of high efficiency air compressor
Save = Air compressor kW reduction per HP: 0.189[1]
Hours = Annual operating hours of the air compressor

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b016	Air Compressor	LBES New	1.00	.99	.n/a	1.00	1.00	1.17	0.98
E21C2b016 E21C3b016	Air Compressor	SBES New Muni New	1.00	1.00	n/a	1.00	1.00	1.17	0.98

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [3]

Coincidence Factors:

CFs from the prospective results of the 2015 study of prescriptive compressed air.[1]

Energy Load Shape:

See Appendix 1 C&I Load Shapes “C&I Compressed Air – VFD Compressor”

Endnotes:

1: DNV GL, October 2015. Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for the MA PAs and EEAC. Result for VSD 25-75 HP used since “All” result includes savings from load/unload compressors, which are now baseline. http://ma-eeac.org/wordpress/wp-content/uploads/MA30-Prescriptive-Chiller-and-CAIR-Report_FINAL_151026.pdf

2: ERS, November 2005. Measure Life Study. Prepared for MA Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf

3: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.3 Compressed Air – Air Nozzle

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity/ Retrofit
Category	Compressed Air

Description:

Covers the installation of engineered air nozzles which provide effective air nozzle action while reducing compressed air system air flow.

Baseline Efficiency:

The baseline efficiency case is a a standard nozzle on a compressed air system.

High Efficiency:

The high efficiency case is an engineered nozzle on the same compressed air system.

Algorithms for Calculating Primary Energy Impact:

Savings are calculated in a spreadsheet tool per the following:

$$\Delta kW = (FLOW_{BASE} - FLOW_{EE}) \times \frac{kW}{cfm}$$

$$\Delta kWh = \Delta kW \times hr$$

Where:

$FLOW_{BASE}$ = base case nozzle flow in cfm, at site specific pressure if available, or else at 100 psig
$FLOW_{EE}$ = energy efficient nozzle flow in cfm, at site specific pressure if available, or else at 100 psig
$\frac{kW}{cfm}$ = site specific compressor efficiency, default value of 0.29 if unavailable

Measure Life:

The measure life is 13 years.

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b017	Air Nozzle	LBES New	1.00	.99	n/a	1.00	1.00	0.80	0.54
E21C2b017 E21C3b017	Air Nozzle	SBES New Muni New	1.00	1.00	n/a	1.00	1.00	0.80	0.54

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [2]

Coincidence Factors:

CFs from the prospective results of the 2015 study of prescriptive compressed air.[1]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Compressed Air – VFD Compressor".

Endnotes:
1: DNV GL, October 2015. Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for Massachusetts Program Administrators and Massachusetts Energy Efficiency Advisory Council. https://ma-eeac.org/wp-content/uploads/MA30-Prescriptive-Chiller-and-CAIR-Report_FINAL_151026.pdf
2:DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

Revision History

Revision Number	Issue Date	Description
42	1/14/2022	Fixed broken link in references

2.4 Compressed Air – Adding Compressor Capacity and/or Storage

Measure Code	[Code]
Market	Commercial
Program Type	Retrofit
Category	Compressed Air

Description:

Adding storage capacity to compressed air systems with previously insufficient storage results in less system pressure fluctuations and allows lower average system pressures, leading to air compressor energy savings when operated at lower system pressures. It also reduces cycling losses in compressor systems that use a compressor with load-unload controls for part-load modulation.

Baseline Efficiency:

The baseline is the site-specific air compressor energy consumption operating at the higher average system pressure with insufficient compressed air storage.

High Efficiency:

The high efficiency case is the site-specific air compressor energy consumption operating at the lower average system pressure after the added compressed air storage, and with reduced cycling losses for load/unload compressors.

Algorithms for Calculating Primary Energy Impact:

The energy savings are based on air compressor energy efficiency improvements resulting from two components: the lower average pressure after air storage capacity is added, and reduced cycling losses. The measure may realize one or both savings components, depending on baseline conditions.

The algorithm for calculating electric demand savings from the system pressure reduction is:

$$\Delta kW_{PR} = kW_{BASE} \times (psi_{BASE} - psi_{EE}) \times 0.4\%$$

Where:
ΔkW_{PR} = Average kW savings from the system pressure reduction
kW_{BASE} = Baseline air compressor system average input kW
psi_{BASE} = Baseline average system pressure, in psi
psi_{EE} = Energy efficient average system pressure with added storage, in psi
0.4%/psi = Compressor kW reduction factor[1]

The algorithm for calculating annual electric energy savings from the system pressure reduction is:

$$\Delta kWh_{PR} = \Delta kW_{PR} \times \frac{hr}{yr}$$

Where:

ΔkWh_{PR} = Gross annual kWh savings from system pressure reduction
ΔkW_{PR} = Average kW savings from the system pressure reduction
$\frac{hr}{yr}$ = Annual compressed air system pressurization hours

The algorithm for calculating savings from the reduction in cycling losses is:

$$\Delta kW_{CL} = kW_{BASE,MOD} \times (\%kW_{BASE} - \%kW_{EE})$$

Where:
ΔkW_{CL} = Average kW savings from the reduction in cycling losses for load/unload compressors
$kW_{BASE,MOD}$ = Baseline air compressor input kW for the load-unload compressor that is the modulating or topping compressor
$\%kW_{BASE}$ = Percentage kW input in the base case (refer to %kW table, interpolate as needed)
$\%kW_{EE}$ = Percentage kW input in the energy efficient case after added storage (refer to % kW table, interpolate as needed)

Average Percent Capacity	**Tank Plus Distribution System Storage per Compressor Capacity** *(use the modulating compressor capacity only)*	**% kW[2]**
25%	1 gal/cfm	70%
	3 gal/cfm	55%
	5 gal/cfm	50%
	10 gal/cfm	48%
50%	1 gal/cfm	88%
	3 gal/cfm	76%
	5 gal/cfm	71%
	10 gal/cfm	68%
75%	1 gal/cfm	96%
	3 gal/cfm	92%
	5 gal/cfm	89%
	10 gal/cfm	86%

The algorithm for calculating annual electric energy savings from the cycling losses is:

$$\Delta kWh_{CL} = \Delta kW_{CL} \times \frac{hr}{yr}$$

Where:
ΔkWh_{CL} = Gross annual kWh savings from the reduction in cycling losses for load/unload compressors
ΔkW_{CL} = Average kW savings from the reduction in cycling losses for load/unload compressors
$\frac{hr}{yr}$ = Annual operating hours of the load/unload topping compressor

Measure Life:

The measure life is 17 years for non-mechanical infrastructure[3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b020	Compressed air – compressor storage	LBES	1.00	.99	n/a	1.00	1.00	1.17	0.98
E21C2b020	Compressed air – compressor storage	SBES	1.00	1.00	n/a	1.00	1.00	1.17	0.98
E21C3b032	Compressed air – compressor storage	Muni	1.00	1.00		1.00	1.00	1.17	0.98

In-Service Rates:

All installations have 100% a in-service-rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [4]

Coincidence Factors:

A summer coincidence factor of 117% and a winter coincidence factor of 98% is utilized.[4]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Compressed Air- VFD Compressor".

Endnotes:

1: Estimate based on ERS data of CAGI Compressor Data Sheets of 40 operating points of 10 compressors from 4 manufacturers, downloaded 5/21/20.

2: Department of Energy Compressed Air Challenge. Improving Compressed Air System Performance A Sourcebook for Industry, Third Edition, DOE/EE-1340, (approx. 2015) p. 40.

3: Energy & Resource Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf Measure life value represents the median MA Measure Life for 15-75 HP Effissient Compressors in the Compressed Air Category shown in Table 3-9 of the study.

4: DNV GL (2015). Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for The Massachusetts Joint Utilities.

5: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.5 Compressed Air – Low Pressure Drop Filter

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Compressed Air

Description:

Filters remove solids and aerosols from compressed air systems. Low pressure drop filters have longer lives and lower pressure drops than traditional coalescing filters, resulting in low air compressor energy use.

Baseline Efficiency:

The baseline efficiency case is a standard coalescing filter with initial drop of between 1 and 2 pounds per sq inch (psi) with an end of life drop of 10 psi.

High Efficiency:

The high efficiency case is a low pressure drop filter with initial drop not exceeding 1 psi over life and 3 psi at element change. Filters must be deep-bed, "mist eliminator" style and installed on a single operating compressor rated 15 - 75 HP.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kW = kW_{BASE} \times (psi_{BASE} - psi_{EE}) \times 0.4\%$$
$$\Delta kWh = \Delta kW \times \frac{hr}{yr}$$

Where:
ΔkW = Average kW savings
ΔkWh = Gross annual kWh savings
kW_{BASE} = Air compressor system average input kW, site specific
psi_{BASE} = Baseline standard filter pressure drop, in psi
psi_{EE} = Energy efficient filter pressure drop, in psi
0.4%/psi = Compressor kW reduction factor[1]
$\frac{hr}{yr}$ = Annual compressed air system pressurization hours

Measure Life:

The measure life is 5 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a032	Low Pressure Drop Filter	LBES Retro	1.00	.99	n/a	1.00	1.00	0.80	0.54
E21C1b043	Low Pressure Drop Filter	LBES New	1.00	.99	n/a	1.00	1.00	0.80	0.54
E21C1d032	Low Pressure Drop Filter	LBES DI	1.00	.99	n/a	1.00	1.00	0.80	0.54
E21C2a032	Low Pressure Drop Filter	SBES Retro	1.00	1.00	n/a	1.00	1.00	0.80	0.54
E21C2b043	Low Pressure Drop Filter	SBES New	1.00	1.00	n/a	1.00	1.00	0.80	0.54
E21C2d032	Low Pressure Drop Filter	SBES DI	1.00	1.00	n/a	1.00	1.00	0.80	0.54
E21C3a055	Low Pressure Drop Filter	Muni Retro	1.00	1.00	n/a	1.00	1.00	0.80	0.54
E21C3b065	Low Pressure Drop Filter	Muni New	1.00	1.00	n/a	1.00	1.00	0.80	0.54
E21C3d055	Low Pressure Drop Filter	Muni DI	1.00	1.00	n/a	1.00	1.00	0.80	0.54

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Realization rates are based on impact evaluation of PY 2004 compressed air installations.[3] Realization rates are based on impact evaluation of NSTAR 2006 compressed air installations.[4] The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [5]

Coincidence Factors:

Summer and winter coincidence factors are CFs based on impact evaluation of PY 2004 compressed air installations.[3]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Compressed Air – VFD Compressor".

Endnotes: :
1: Estimate based on ERS data of CAGI Compressor Data Sheets of 40 operating points of 10 compressors from 4 manufacturers, downloaded 5/21/20.
2: ERS, November 2005. Measure Life Study. Prepared for MA Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
3: DMI, 2006. Impact Evaluation of 2004 Compressed Air Prescriptive Rebates. Results analyzed in RLW Analytics, 2006. Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in Energy Initiative and Design 2000 Programs.
4: LW Analytics, 2008. Business & Construction Solutions (BS/BC) Programs Measurement & Verification - 2006 Final Report.

DNV GL (2015). Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for The Massachusetts Joint Utilities.

DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.6 Compressed Air – Refrigerated Air Dryer

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Compressed Air

Description:

The installation of cycling or variable frequency drive (VFD)-equipped refrigerated compressed air dryers. Refrigerated air dryers remove the moisture from a compressed air system to enhance overall system performance. An efficient refrigerated dryer cycles on and off or uses a variable speed drive as required by the demand for compressed air instead of running continuously. Only properly sized refrigerated air dryers used in a single-compressor system are eligible.

Baseline Efficiency:

The baseline efficiency case is a non-cycling refrigerated air dryer.

High Efficiency:

The high efficiency case is a cycling refrigerated dryer or a refrigerated dryer equipped with a VFD.

Algorithms for Calculating Primary Energy Impact:

Δ kWh = (CFM DRYER) x (Save) x (HRS)
Δ kW = (CFM DRYER) x (Save)
Where:
CFM DRYER = Full flow rated capacity of the refrigerated air dryer in cubic feet per minute (CFM) obtained from equipment's Compressed Air Gas Institute Datasheet.
Save = Refrigerated air dryer kW reduction per dryer full flow rated CFM: 0.00554[1]
HRS = Annual operating hours of the refrigerated air dryer

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b047	Refrigerated Air Dryer	LBES New	1.00	1.56	n/a	1.00	1.00	1.17	0.98

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C2b047	Refrigerated Air Dryer	SBES New	1.00	1.56	n/a	1.00	1.00	1.17	0.98
E21C3b078	Refrigerated Air Dryer	Muni New	1.00	1.56	n/a	1.00	1.00	1.17	0.98

In-Service Rates:

All installations have a 100% in-service rates unless an evaluation finds otherwise.

Realization Rates:

Realization rates are from the prospective results of the 2015 study of prescriptive compressed air.[1]

Coincidence Factors:

Summer and winter coincidence factors are from the prospective results of the 2015 study of prescriptive compressed air. [1]

Energy Load Shape:

See Appendix 1, C&I Load Shapes Table "C&I Compressed Air – Air Dryer"

Endnotes:

1 DNV GL, October 2015. Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for MA Joint Utilities and MA EEAC. http://ma-eeac.org/wordpress/wp-content/uploads/MA30-Prescriptive-Chiller-and-CAIR-Report_FINAL_151026.pdf

2: ERS, November 2005. Measure Life Study. Prepared for MA Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf

2.7 Compressed Air – Zero Loss Condensate Drain

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Compressed Air

Description:

Drains remove water from a compressed air system. Zero loss condensate drains remove water from a compressed air system without venting any air, resulting in less air demand and consequently less air compressor energy use.

Baseline Efficiency:

The baseline efficiency case a standard condensate drain on a compressor system.

High Efficiency:

The high efficiency case is installation of a zero loss condensate drain on a single operating compressor rated ≤ 75 HP.

Algorithms for Calculating Primary Energy Impact:

ΔkWh = (CFMpipe) x (CFMsave) x (Save) x (Hours)
ΔkW = (CFMpipe) x (CFMsave) x (Save)
Where:
ΔkWh = Energy Savings
ΔkW = Demand savings
CFMpipe = CFM capacity of piping that is served by the condensate drain, site specific
CFMsaved = Average CFM saved per CFM of piping capacity: 0.049[1]
Save = Average savings per CFM, site specific if available, default value of 0.21 kW/CFM[1]
Hours = Annual operating hours of the zero loss condensate drain.

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a046	Zero Loss Condensate Drains	LBES Retro	1.00	.99	1.00	1.00	1.00	0.80	0.54
E21C1b051	Zero Loss Condensate Drains	LBES New	1.00	.99	1.00	1.00	1.00	0.80	0.54
E21C1d046	Zero Loss Condensate Drains	LBES DI	1.00	.99	1.00	1.00	1.00	0.80	0.54
E21C2a046	Zero Loss Condensate Drains	SBES Retro	1.00	1.00	1.00	1.00	1.00	0.80	0.54
E21C2b051	Zero Loss Condensate Drains	SBES New	1.00	1.00	1.00	1.00	1.00	0.80	0.54
E21C2d046	Zero Loss Condensate Drains	SBES DI	1.00	1.00	1.00	1.00	1.00	0.80	0.54
E21C3a090	Zero Loss Condensate Drains	Muni Retro	1.00	1.00	1.00	1.00	1.00	0.80	0.54
E21C3b082	Zero Loss Condensate Drains	Muni New	1.00	1.00	1.00	1.00	1.00	0.80	0.54
E21C3d090	Zero Loss Condensate Drains	Muni DI	1.00	1.00	1.00	1.00	1.00	0.80	0.54

In-Service Rates:

All installations have a 100% in-service rate since unless an evaluation finds otherwise.

Realization Rates:

All program use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [3]

Coincidence Factors:

Summer and winter coincidence factors are based on Massachusetts TRM values. Latest 2015 evaluation study did not yield a statistically significant sample size for updating CF values.

Energy Load Shape:

See Appendix 1, C&I Load Shapes Table "C&I Compressed Air – VFD Compressor"

Endnotes:
1: Prescriptive_CAIR_ZLD_LPDF_Tool.xlsx referenced by the Massachusetts TRM.
2: Energy & Resource Solutions, November 2005. Measure Life Study. Prepared for Massachusetts Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf

3: DNV GL (2015). Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for The Massachusetts Joint Utilities.
DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.8 Custom Measures

Measure Code	[Code]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Custom

Description:

The Custom project track is offered for electric and natural gas energy efficiency projects involving complex site-specific applications that require detailed engineering analysis and/or projects which do not qualify for incentives under any of the prescriptive rebate offering.

Baseline Efficiency:

Retrofit projects will use the existing system or performance as the baseline for all single baseline projects. Lost opportunity projects will generally refer to code, until such time as the EM&V working group selects appropriate ISP values from relevant research. Other factors being equal, New Hampshire jurisdiction-specific results will be favored over results from other jurisdictions, however when relevant results exist from both New Hampshire and from other states, it may be necessary to balance the desirable attributes of state-specificity and data reliability. When considering whether to apply results from a study originating in another jurisdiction to New Hampshire programs, the EM&V working group (with support from independent evaluation firms as needed), will make the determination based on 1) the similarity of evaluated program/measures to those offered in NH; 2) the similarity of relevant markets and customer base, 3) the recency of the study relative to the recency of any applicable NH results, and 4) the quality of the study's methodology and sample size. If a relevant ISP has been established, lost opportunity projects should refer to that ISP if applicable. If code does not apply and an ISP is not available, engineering judgement should be used to determine a project baseline.High Efficiency:
The high efficiency scenario is specific to the custom project and may include one or more energy efficiency measures. Energy and demand savings calculations are based on projected or measured changes in equipment efficiencies and operating characteristics and are determined on a case-by-case basis.

Algorithms for Calculating Primary Energy Impact:

Gross energy and demand savings estimates for custom projects are calculated using engineering analysis with project-specific details. Custom analyses typically include a weather dependent load bin analysis, whole building energy model simulation, end-use metering or other engineering analysis and include estimates of savings, costs, and an evaluation of the projects' cost-effectiveness.

Measure Life:

For both lost-opportunity and retrofit custom applications, the measure life is determined on a case-by-case basis.[2]

Other Resource Impacts:

Other resource impacts should be determined on a case by case basis for custom projects.

Impact Factors for Calculating Adjusted Gross Savings:[1]

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b001	Custom Large Compressed Air New	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1a001	Custom Large Compressed Air Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1d001	Custom Large Compressed Air Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1b002	Custom Large Hot Water New	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1a002	Custom Large Hot Water Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1d002	Custom Large Hot Water Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1b003	Custom Large HVAC New	LBES	1.000	0.900	0.87	1.000	1.000	1.00	0.385
E21C1a003	Custom Large HVAC Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C1d003	Custom Large HVAC Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C1b004	Custom Large Lighting New – Interior	LBES	1.000	0.990	n/a	1.000	1.000	0.80	0.61
E21C1b054	Custom Large Lighting New – Exterior	LBES	1.000	0.990	n/a	1.000	1.000	0.00	1.00
E21C1b055	Custom Large Lighting New – Controls	LBES	1.000	0.990	n/a	1.000	1.000	0.15	0.13
E21C1a004	Custom Large Lighting Retro – Interior	LBES	1.000	0.990	n/a	1.000	1.000	0.80	0.61
E21C1a047	Custom Large Lighting Retro – Exterior	LBES	1.000	0.990	n/a	1.000	1.000	0.00	1.00
E21C1a048	Custom Large Lighting Retro – Controls	LBES	1.000	0.990	n/a	1.000	1.000	0.15	0.13
E21C1d004	Custom Large Lighting Direct Install – Interior	LBES	1.000	0.990	n/a	1.000	1.000	0.80	0.61
E21C1d005	Custom Large Lighting Direct Install – Exterior	LBES	1.000	0.990	n/a	1.000	1.000	0.00	1.00
E21C1d006	Custom Large Lighting Direct Install – Controls	LBES	1.000	0.990	n/a	1.000	1.000	0.15	0.13
E21C1b005	Custom Large Motors New	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1a005	Custom Large Motors Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.92	0.90
E21C1d007	Custom Large Motors Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.92	0.90

E21C1b008	Custom Large Other New	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1a008	Custom Large Other Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1a010	Custom Large Other Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C1b006	Custom Large Process New	LBES	1.000	0.900	0.87	1.000	1.000	0.95	0.45
E21C1a006	Custom Large Process Retro	LBES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C1d008	Custom Large Process Direct Install	LBES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C1b007	Custom Large Refrigeration New	LBES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C1a007	Custom Large Refrigeration Retro	LBES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C1d009	Custom Large Refrigeration Direct Install	LBES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C1b056	Custom Large Comprehensive Design	LBES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C3b001	Custom Muni Compressed Air New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a001	Custom Muni Compressed Air Retro	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3d001	Custom Muni Compressed Air Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3b002	Custom Muni Hot Water New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a002	Custom Muni Hot Water Retro	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3d002	Custom Muni Hot Water Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3b003	Custom Muni HVAC New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a003	Custom Muni HVAC Retro	MES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C3d003	Custom Muni HVAC Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C3b004	Custom Muni Lighting New – Interior	MES	1.000	1.066	n/a	1.000	1.000	0.00	0.00
E21C3b085	Custom Muni Lighting New – Exterior	MES	1.000	1.027	n/a	1.000	1.000	0.00	0.00
E21C3b086	Custom Muni Lighting New – Controls	MES	1.000	1.00	n/a	1.000	1.000	0.00	0.00
E21C3a004	Custom Muni Lighting Retro – Interior	MES	1.000	1.066	n/a	1.000	1.000	0.80	0.61
E21C3a091	Custom Muni Lighting Retro – Exterior	MES	1.000	1.027	n/a	1.000	1.000	0.00	1.00
E21C3a092	Custom Muni Lighting Retro – Controls	MES	1.000	1.00	n/a	1.000	1.000	0.15	0.13
E21C3d004	Custom Muni Lighting Direct Install – Interior	MES	1.000	1.066	n/a	1.000	1.000	0.80	0.61
E21C3d005	Custom Muni Lighting Direct Install – Exterior	MES	1.000	1.027	n/a	1.000	1.000	0.00	1.00

E21C3d006	Custom Muni Lighting Direct Install – Controls	MES	1.000	1.00	n/a	1.000	1.000	0.15	0.13
E21C3b005	Custom Muni Motors New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a005	Custom Muni Motors Retro	MES	1.000	0.900	0.87	1.000	1.000	0.92	0.90
E21C3d007	Custom Muni Motors Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.92	0.90
E21C3b008	Custom Muni Other New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a008	Custom Muni Other Retro	MES	1.000	0.900	0.87	1.000	1.000	0.476	0.428
E21C3d010	Custom Muni Other Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.476	0.428
E21C3b006	Custom Muni Process New	MES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C3a006	Custom Muni Process Retro	MES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C3d008	Custom Muni Process Direct Install	MES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C3b007	Custom Muni Refrigeration New	MES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C3a007	Custom Muni Refrigeration Retro	MES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C3d009	Custom Muni Refrigeration Direct Install	MES	1.000	0.900	n/a	1.000	1.000	0.00	0.00
E21C2b001	Custom Small Compressed Air New	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2a001	Custom Small Compressed Air Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2d001	Custom Small Compressed Air Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2b002	Custom Small Hot Water New	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2a002	Custom Small Hot Water Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2d002	Custom Small Hot Water Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.00	0.00
E21C2b003	Custom Small HVAC New	SBES	1.000	0.900	0.87	1.000	1.000	1.00	0.385
E21C2a003	Custom Small HVAC Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C2d003	Custom Small HVAC Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.70	0.85
E21C2b004	Custom Small Lighting New - Interior	SBES	1.000	1.066	n/a	1.000	1.000	0.80	0.61
E21C2b054	Custom Small Lighting New - Exterior	SBES	1.000	1.027	n/a	1.000	1.000	0.00	1.00
E21C2b055	Custom Small Lighting New - Controls	SBES	1.000	1.00	n/a	1.000	1.000	0.15	0.13
E21C2a004	Custom Small Lighting Retro - Interior	SBES	1.000	1.066	n/a	1.000	1.000	0.70	0.85
E21C2a047	Custom Small Lighting Retro- Exterior	SBES	1.000	1.027	n/a	1.000	1.000	0.80	0.61
E21C2a048	Custom Small Lighting Retro - Controls	SBES	1.000	1.00	n/a	1.000	1.000	0.15	0.13

E21C2d004	Custom Small Lighting Direct Install - Interior	SBES	1.000	1.066	n/a	1.000	1.000	0.70	0.85
E21C2d005	Custom Small Lighting Direct Install - Exterior	SBES	1.000	1.027	n/a	1.000	1.000	0.80	0.61
E21C2d006	Custom Small Lighting Direct Install - Controls	SBES	1.000	1.00	n/a	1.000	1.000	0.15	0.13
E21C2b005	Custom Small Motors New	SBES	1.000	0.900	0.87	1.000	1.000	0.95	0.80
E21C2a005	Custom Small Motors Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.92	0.90
E21C2d007	Custom Small Motors Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.92	0.90
E21C2b008	Custom Small Other New	SBES	1.000	0.900	0.87	1.000	1.000	0.476	0.428
E21C2a008	Custom Small Other Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.45	0.52
E21C2d010	Custom Small Other Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.45	0.52
E21C2b006	Custom Small Process New	SBES	1.000	0.900	0.87	1.000	1.000	0.95	0.45
E21C2a006	Custom Small Process Retro	SBES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C2d008	Custom Small Process Direct Install	SBES	1.000	0.900	0.87	1.000	1.000	0.95	0.90
E21C2b007	Custom Small Refrigeration New	SBES	1.000	0.900	n/a	1.000	1.000	0.80	0.80
E21C2a007	Custom Small Refrigeration Retro	SBES	1.000	0.900	n/a	1.000	1.000	0.90	0.99
E21C2d009	Custom Small Refrigeration Direct Install	SBES	1.000	0.900	n/a	1.000	1.000	0.90	0.99
E21C2b056	Custom Small Comprehensive Design	SBES	1.000	0.900	n/a	1.000	1.000	0.90	0.99
G21C1a001	Custom Large Hot Water Retro	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1a002	Custom Large HVAC Retro	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1a003	Custom Large Other Retro	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1a004	Custom Large Process Retro	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1b001	Custom Large Hot Water New	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1b002	Custom Large HVAC New	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1b003	Custom Large Other New	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C1b004	Custom Large Process New	LBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2a001	Custom Small Hot Water Retro	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2a002	Custom Small HVAC Retro	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2a003	Custom Small Other Retro	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2a004	Custom Small Process Retro	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a

G21C2b001	Custom Small Hot Water New	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2b002	Custom Small HVAC New	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2b003	Custom Small Other New	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a
G21C2b004	Custom Small Process New	SBES	1.000	n/a	0.87	n/a	n/a	n/a	n/a

Impact Factors for Calculating Net Savings:

Free-ridership and spillover for custom lighting are based on study results from CT the nearby jurisdiction with programs and markets most similar to those in NH.[4]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C2b004	Custom Small Lighting New - Interior	SBES	16%	5%	0%	89%
E21C2b054	Custom Small Lighting New - Exterior	SBES	16%	5%	0%	89%
E21C2b055	Custom Small Lighting New - Controls	SBES	16%	5%	0%	89%
E21C2a004	Custom Small Lighting Retro - Interior	SBES	16%	5%	0%	89%
E21C2a047	Custom Small Lighting Retro- Exterior	SBES	16%	5%	0%	89%
E21C2a048	Custom Small Lighting Retro - Controls	SBES	16%	5%	0%	89%
E21C2d004	Custom Small Lighting Direct Install - Interior	SBES	16%	5%	0%	89%
E21C2d005	Custom Small Lighting Direct Install - Exterior	SBES	16%	5%	0%	89%
E21C2d006	Custom Small Lighting Direct Install - Controls	SBES	16%	5%	0%	89%
E21C3b004	Custom Muni Lighting New – Interior	MES	16%	5%	0%	89%
E21C3b085	Custom Muni Lighting New – Exterior	MES	16%	5%	0%	89%
E21C3b086	Custom Muni Lighting New – Controls	MES	16%	5%	0%	89%
E21C3a004	Custom Muni Lighting Retro – Interior	MES	16%	5%	0%	89%
E21C3a091	Custom Muni Lighting Retro – Exterior	MES	16%	5%	0%	89%
E21C3a092	Custom Muni Lighting Retro – Controls	MES	16%	5%	0%	89%
E21C3d004	Custom Muni Lighting Direct Install – Interior	MES	16%	5%	0%	89%
E21C3d005	Custom Muni Lighting Direct Install – Exterior	MES	16%	5%	0%	89%

E21C3d006	Custom Muni Lighting Direct Install – Controls	MES	16%	5%	0%	89%
E21C1b004	Custom Large Lighting New – Interior	LBES	16%	5%	0%	89%
E21C1b054	Custom Large Lighting New – Exterior	LBES	16%	5%	0%	89%
E21C1b055	Custom Large Lighting New – Controls	LBES	16%	5%	0%	89%
E21C1a004	Custom Large Lighting Retro – Interior	LBES	16%	5%	0%	89%
E21C1a047	Custom Large Lighting Retro – Exterior	LBES	16%	5%	0%	89%
E21C1a048	Custom Large Lighting Retro – Controls	LBES	16%	5%	0%	89%
E21C1d004	Custom Large Lighting Direct Install – Interior	LBES	16%	5%	0%	89%
E21C1d005	Custom Large Lighting Direct Install – Exterior	LBES	16%	5%	0%	89%
E21C1d006	Custom Large Lighting Direct Install – Controls	LBES	16%	5%	0%	89%

Energy Load Shape:

See Appendix 1, C&I Load Shapes Table

- "C&I Interior Lighting – Prescriptive"
- "C&I Exterior Lighting"
- "C&I Lighting Controls"
- "C&I- Refrigeration"

Endnotes:

1: Realization rates for custom non lighting measures are based on a weighted average of realization rates from jurisdictions within New England, with a 50% weight for New Hampshire. To be updated once the Large C&I Custom Impact Evaluation is complete in 2021/2022.
Realization rates for custom lighting measures are based on DNV GL, September 2015. New Hampshire Utilities Large Commercial and Industrial (C&I) Retrofit And New Equipment & Construction Program Impact Evaluation.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2: Energy & Resource Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities; Table 1-2. ERS_2005_Measure_Life_Study

3: Baseline Categories and preliminary Out Year Factors are described at a high level in DNV GL, ERS (2018). Portfolio Model Companion Sheet. Additional background on the baseline categorization given in DNV GL, ERS (2018). Portfolio Model Methods and Assumptions – Electric and Natural Gas Memo. 2018_DNVGL_ERS_Portfolio_Model_Companion_Sheet

4: EMI, September 25, 2019 . C1644 EO Net-to-Gross Study, Final Report.
https://www.energizect.com/sites/default/files/C1644%20-%20EO%20NTG%20Final%20Report_9.25.19.pdf

Downstream NTG values are based on Energy Opportunities NTG Study Results for Lighting shown in Table ES-1-1 on p. ES-3.

2.9 Food Service – Conveyor Broiler

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an energy efficient underfired broiler to replace a conventional automatic constant input rate conveyor broiler. This measure has both electric and gas savings.

Baseline Efficiency:

Baseline broiler must be an automatic conveyor broiler capable of maintaining a temperature above 600 F with a tested idle rate greater than:

- 40 kBtu/h for a belt narrower than 22"
- 60 kBtu/h for a belt between 22 and 28"
- 70 kBtu/h for a belt wider than 28"

High Efficiency:

An efficient conveyor broiler must be installed with a catalyst and have an input rate of less than 80 kBtu/h OR a dual-stage or modulating gas valve with a capacity of throttling the input rate below 80 kBtu/h. Must be installed under a Type II Hood.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on the SoCalGas Commercial Conveyor Broilers workpaper WPSCGNRCC171226A.[1]

BC ID	Measure Name	Program	ΔkWh[1]	ΔkW[1]	Δtherms[1]
E21C1c047 E21C2c047	Conveyor Broiler <22”	LBES Mid SBES Mid	7,144	1.48	1,145
E21C1c047 E21C2c047	Conveyor Broiler 22-38	LBES Mid SBES Mid	6,403	.88	1,933
E21C1c047 E21C2c047	Conveyor Broiler >28”	LBES Mid SBES Mid	23,849	3.29	3,161

Measure Life:

The measure life for a conveyor broiler is 12 years. [2]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c047 E21C2c047	Conveyor Broiler <22”	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90
E21C1c047 E21C2c047	Conveyor Broiler 22-26	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90
E21C1c047 E21C2c047	Conveyor Broiler >26”	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[1]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes “LS_111 C&I Food Service”

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[3]	SO_P[3]	SO_{NP}[3]	NTG[3]
E21C1c047 E21C2c047	Conveyor Broiler <22”	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c047 E21C2c047	Conveyor Broiler 22-26	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c047 E21C2c047	Conveyor Broiler >26”	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: SoCalGas, 2019. “WPSCGNRCC171226A – Commercial Conveyor Broilers” Revision 01.
2: California Public Utilities Commission (CPUC), Energy Division. 2014. “DEER2014-EUL-table-update_2014-02-05.xlsx” https://www.caetrm.com/media/reference-documents/DEER2014-EUL-table-update_2014-02-05_PUq4NzL.xlsx
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors’ Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

Revision Number	Date	Revision
60	3/1/2022	New Measure Added

2.10 Food Service – Deck Oven

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of a Food Service Technology Center (FSTC) pre-approved electric deck oven, with greater than 60% efficiency and less than 1.3 kw idle rate. A commercial electric deck oven is an appliance that cooks food product within a heated chamber. The food product can be placed directly on the floor of the chamber during cooking and energy is delivered to the food product by convective, conductive, or radiant heat transfer. The chamber can be heated by electric forced convection, radiation, or quartz tubes. Top and bottom heat of the oven can be independently controlled.

Baseline Efficiency:

The baseline is defined as a commercial electric deck oven with equal to or greater than 40% cooking efficiency, an idle energy rate less than or equal to 1.9 kW and a measure pre heat energy of less than or equal to 6.5 kWh.[1]

High Efficiency:

An efficient deck oven is defined as having greater than or equal to 60% efficiency, less than or equal to 1.3 Kw idle energy rate, and a preheat energy us of less than or equal to 3 kWh and included on the Food Service Technology Center (FSTC) pre-approved list found at : https://caenergywise.com/rebates/

Algorithms for Calculating Primary Energy Impact:

Deemed Savings:

BC ID	Measure Name	Program	ΔkWh[1,2]	ΔkW[1,2]
E21C1c050 E21C2c050	Electric Deck Oven	LBES Mid SBES Mid	7,519	1.545

Measure Life:

The measure life for an electric deck oven is 12 years. [3]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c050 E21C2c050	Electric Deck Oven	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[5]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "LS_111 C&I Food Service"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[4]	SO_P[4]	SO_{NP}[4]	NTG[4]
	Electric Deck Oven	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: California ETRM, Electric Deck Ovens (2020), value based on the Food Service Technology Center (FSTC). (n.d.) Proprietary database.
2: Southern California Edison (SCE). 2018. "SCE17CC012.1 A2 - Cost & Savings Calculations.xlsm." https://www.caetrm.com/media/reference-documents/SCE17CC012.1_A2_-_Cost__Savings_Calculations.xlsm
3:Robert Mowris & Associates. 2005. Ninth Year Retention Study of the 1995 Southern California Gas Company Commercial New Construction Program. Prepared for Southern California Gas Company. Study ID Number 718A. https://www.caetrm.com/media/reference-documents/Ninth_Year_Retention_Study_No_718A_for_1995_SCG_CNC_Program.pdf
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52
5: SoCalGas, 2019. "WPSCGNRCC171226A – Commercial Conveyor Broilers" Revision 01.

Revision Number	Date	Revision
61	3/1/2022	New Measure Added

2.11 Food Service – Dishwasher

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Dishwasher High Temperature: Installation of a qualified ENERGY STAR® high temperature commercial dishwasher in a building with gas domestic hot water. High temperature dishwashers use a booster heater to raise the rinse water temperature to 180 F – hot enough to sterilize dishes and assist in drying. Electric savings are achieved through savings to the electric booster.

Dishwasher Low Temperature: Installation of a qualified ENERGY STAR® low temperature commercial dishwasher in a facility with electric hot water heating. Low temperature dishwashers use the hot water supplied by the kitchen's existing water heater and use a chemical sanitizing agent in the final rinse cycle and sometimes a drying agent.

Baseline Efficiency:

Dishwasher High Temp: The baseline efficiency case is a commercial dishwasher with idle energy rates and water consumption as follows[1]:

Dishwasher Type	Idle Energy Rate (kW)	Water Consumption (gal/rack)
High Temp Under Counter Dishwasher	0.76	1.09
High Temp Door Type Dishwasher	0.87	1.29
High Temp Single Tank Conveyer Dishwasher	1.93	0.87
High Temp Multi Tank Conveyer Dishwasher	2.59	0.97
High Temp Pots & Pans Dishwasher	1.20	0.70

Dishwasher Low Temp: The baseline efficiency case is a commercial dishwasher with idle energy rates and water consumption as follows[1]:

Dishwasher Type	Idle Energy Rate (kW)	Water Consumption (gal/rack)
Low Temp Under Counter Dishwasher	0.50	1.73
Low Temp Door Type Dishwasher	0.60	2.10
Low Temp Single Tank Conveyor Dishwasher	1.60	1.31

Low Temp Multi Tank Conveyor Dishwasher	2.00	1.04

High Efficiency:

Dishwasher High Temp: The high efficiency case is a commercial dishwasher with idle energy rates and water consumption following ENERGY STAR® Efficiency Requirements[2] as follows:

Dishwasher Type	Idle Energy Rate (kW)	Water Consumption (gal/rack)
High Temp Under Counter Dishwasher	0.50	0.86
High Temp Door Type Dishwasher	0.70	0.89
High Temp Single Tank Conveyer Dishwasher	1.50	0.70
High Temp Multi Tank Conveyer Dishwasher	2.25	0.54
High Temp Pots & Pans Dishwasher	1.20	0.58

Dishwasher Low Temp: The high efficiency case is a commercial dishwasher with idle energy rates and water consumption following ENERGY STAR® Efficiency Requirements[2] as follows:

Dishwasher Type	Idle Energy Rate (kW)	Water Consumption (gal/rack)
Low Temp Under Counter Dishwasher	0.50	1.19
Low Temp Door Type Dishwasher	0.60	1.18
Low Temp Single Tank Conveyor Dishwasher	1.60	0.79
Low Temp Multi Tank Conveyor Dishwasher	2.00	0.54

Algorithms for Calculating Primary Energy Impact:

Dishwasher High Temp: Unit savings are deemed based on the Energy Star Commercial Kitchen Equipment Savings Calculator[1]:
kWh = kWh
kW = kWh / hours
MMBtu = MMBtu

Where:
kWh = gross annual kWh savings from the measure. See table below.
kW = gross average kW savings from the measure. See table below.
MMBtu = gross average natural gas MMBtu savings from the measure. See table below.

Hours = Average annual equipment operating hours is 18 hours/ day, 6,570 hours/year.

BC Measure ID	Measure	Program	ΔkW	ΔkWh	ΔMMBtu
E21C1b026 E21C2b026 E21C3b040 E21C1c024 E21C2c024	High Temp Under Counter Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	0.32	1,791	n/a
E21C1b022 E21C2b022 E21C3b036 E21C1c020 E21C2c020	High Temp Door Type Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	0.74	4,151	n/a
E21C1b025 E21C2b025 E21C3b039 E21C1c023 E21C2c023	High Temp Single Tank Conveyer Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	0.75	4,243	n/a
E21C1b023 E21C2b023 E21C3b037 E21C1c021 E21C2c021	High Temp Multi Tank Conveyer Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	1.71	9,630	n/a
E21C1b024 E21C2b024 E21C3b038 E21C1c022 E21C2c022	High Temp Pots & Pans Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	0.18	1,032	n/a
E21C1b030 E21C2b030 E21C3b044 E21C1c028 E21C2c028	Low Temp Under Counter Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	0.39	2,178	n/a
E21C1b027 E21C2b027 E21C3b041 E21C1c025 E21C2c025	Low Temp Door Type Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	2.46	13,851	n/a
E21C1b029 E21C2b029 E21C3b043 E21C1c027 E21C2c027	Low Temp Single Tank Conveyor Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	2.07	11,685	n/a

E21C1b028 E21C2b028 E21C3b042 E21C1c026 E21C2c026	Low Temp Multi Tank Conveyor Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	2.86	16,131	n/a

Measure Life:

The measure life for a new high temperature dishwasher is given by type below [3]:

BC Measure ID	Measure Name	Program	Measure Life
E21C1b026 E21C2b026 E21C3b040 E21C1c024 E21C2c024	High Temp Under Counter Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	10
E21C1b022 E21C2b022 E21C3b036 E21C1c020 E21C2c020	High Temp Door Type Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	15
E21C1b025 E21C2b025 E21C3b039 E21C1c023 E21C2c023	High Temp Single Tank Conveyer Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	20
E21C1b023 E21C2b023 E21C3b037 E21C1c021 E21C2c021	High Temp Multi Tank Conveyer Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	20
E21C1b024 E21C2b024 E21C3b038 E21C1c022 E21C2c022	High Temp Pots & Pans Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	10
E21C1b030 E21C2b030 E21C3b044 E21C1c028 E21C2c028	Low Temp Under Counter Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	10

E21C1b027 E21C2b027 E21C3b041 E21C1c025 E21C2c025	Low Temp Door Type Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	15
E21C1b029 E21C2b029 E21C3b043 E21C1c027 E21C2c027	Low Temp Single Tank Conveyor Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	20
E21C1b028 E21C2b028 E21C3b042 E21C1c026 E21C2c026	Low Temp Multi Tank Conveyor Dishwasher	LBES New SBES New Muni New LBES Mid SBES Mid	20

Other Resource Impacts:

Dishwasher high temp: There are water savings associated with this measure. [1]

Dishwasher Type	Annual water savings (gal/unit)
High Temp Under Counter Dishwasher	5,399
High Temp Door Type Dishwasher	35,056
High Temp Single Tank Conveyer Dishwasher	21,284
High Temp Multi Tank Conveyer Dishwasher	80,754
High Temp Pots & Pans Dishwasher	10,517

Dishwasher low temp: There are water savings associated with this measure. [1]

Dishwasher Type	Annual water savings (gal/unit)
Low Temp Under Counter Dishwasher	12,677
Low Temp Door Type Dishwasher	80,629
Low Temp Single Tank Conveyor Dishwasher	65,104
Low Temp Multi Tank Conveyor Dishwasher	93,900

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b026 E21C2b026 E21C3b040 E21C1c024 E21C2c024	High Temp Under Counter Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b022 E21C2b022 E21C3b036 E21C1c020 E21C2c020	High Temp Door Type Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b025 E21C2b025 E21C3b039 E21C1c023 E21C2c023	High Temp Single Tank Conveyer Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b023 E21C2b023 E21C3b037 E21C1c021 E21C2c021	High Temp Multi Tank Conveyer Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b024 E21C2b024 E21C3b038 E21C1c022 E21C2c022	High Temp Pots & Pans Dishwasher	SBES New LBES Mid SBES Mid Muni New	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b030 E21C2b030 E21C3b044 E21C1c028 E21C2c028	Low Temp Under Counter Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b027 E21C2b027 E21C3b041 E21C1c025 E21C2c025	Low Temp Door Type Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b029 E21C2b029 E21C3b043 E21C1c027 E21C2c027	Low Temp Single Tank Conveyor Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b028 E21C2b028	Low Temp Multi Tank Conveyor Dishwasher	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3b042 E21C1c026 E21C2c026									
E21C1b026 E21C2b026 E21C3b040	High Temp Under Counter Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b022 E21C2b022 E21C3b036	High Temp Door Type Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b025 E21C2b025 E21C3b039	High Temp Single Tank Conveyer Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b023 E21C2b023 E21C3b037	High Temp Multi Tank Conveyer Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b024 E21C2b024 E21C3b038	High Temp Pots & Pans Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b030 E21C2b030 E21C3b044	Low Temp Under Counter Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b027 E21C2b027 E21C3b041	Low Temp Door Type Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b029 E21C2b029 E21C3b043	Low Temp Single Tank Conveyor Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b028 E21C2b028 E21C3b042	Low Temp Multi Tank Conveyor Dishwasher	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90

In-Service Rates:

In-service rates are assumed to be 100% until an evaluation finds otherwise.

Realization Rates:

Realization rates are assumed to be 100% until an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [4]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[5]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c024 E21C2c024	High Temp Under Counter Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c020 E21C2c020	High Temp Door Type Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c023 E21C2c023	High Temp Single Tank Conveyer Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c021 E21C2c021	High Temp Multi Tank Conveyer Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c022 E21C2c022	High Temp Pots & Pans Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c028 E21C2c028	Low Temp Under Counter Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c025 E21C2c025	Low Temp Door Type Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c027 E21C2c027	Low Temp Single Tank Conveyor Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c026 E21C2c026	Low Temp Multi Tank Conveyor Dishwasher	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Energy Load Shape:

See Appendix 1, C&I Load Shapes Table- "C&I Food Services"

Endnotes:

1. ENERGY STAR Commercial Kitchen Equipment Calculator. Updated October 2016.
   Note: High temperature units are assumed to have natural gas hot water and electric temperature boosters. Low temperature units are assumed to have electric hot water. ENERGY STAR notes that a new version of the calculator will be available in fall 2020.
2. ENERGY STAR Commercial Dishwashers Key Product Criteria, version 2.0. Effective Feb 1, 2013.
   Note: ENERGY STAR Commercial Dishwashers product specification version 3.0 is in its final form as of October 27, 2020 and will go into effect July 27, 2021.
3. FSTC Life Cycle Savings Calculators https://fishnick.com/saveenergy/tools/calculators/
4. DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
   https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

5. NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.12 Food Service – Fryer

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Electric Fryer: Installation of a qualified ENERGY STAR standard or large vat commercial fryer. ENERGY STAR commercial fryers save energy during cooking and idle times due to improved cooking efficiency and idle energy rates.

Gas Fryer: The installation of a natural-gas fired fryer that is either ENERGY STAR rated or has a heavy-load cooking efficiency of at least 50%. Qualified fryers use advanced burner and heat exchanger designs to use fuel more efficiently, as well as increased insulation to reduce standby heat loss.

Baseline Efficiency:

Electric Fryer: The baseline efficiency case for both, standard sized fryers and large capacity fryers is an electric deep-fat fryer of the same size with a cooking energy efficiency, shortening capacity, and idle energy rate as defined by any relevant U.S. federal requirements.

Gas Fryer: The baseline efficiency case is a gas deep-fat fryer of the same size with a cooking energy efficiency, shortening capacity, and idle energy rate as defined by any relevant U.S. federal requirements.

High Efficiency:

Electric Fryer: The high efficiency case for both, standard sized fryer and large capacity fryers is an electric deep-fat fryer with a cooking energy efficiency, shortening capacity, and idle energy rate in line with ENERGY STAR requirements.

Gas Fryer: The high efficiency case is an fryers is a deep-fat gas fryer with a cooking energy efficiency, shortening capacity, and idle energy rate in line with ENERGY STAR requirements.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = \Delta kWh$
$\Delta kW = \Delta kWh / Hours$
Where:
ΔkWh = gross annual kWh savings from the measure per table below
ΔkW = gross average kW savings from the measure per table below
Hours = Annual hours of operation

$\Delta MMBtu = \Delta MMBtu$
Where:
$\Delta MMBtu$ = gross annual MMBtu gas savings from the measure per table below

Energy Savings for Commercial Fryer:

BC Measure ID	Measure Name	Program	ΔkW	ΔkWh	ΔMMBtu
E21C1b033 E21C2b033 E21C3b050 E21C1c032 E21C2c032	Electric Fryer, Standard Vat	LBES New SBES New Muni LBES Mid SBES Mid	0.50	2,976	n/a
E21C1b032 E21C2b032 E21C3b049 E21C1c031 E21C2c031	Electric Fryer, Large Vat	LBES New SBES New Muni LBES Mid SBES Mid	0.50	2,841	n/a
G21C1b024 G21C2b024 G21C1c004 G21C2c004	Gas Fryer	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	78.3

Measure Life:

The measure life for a new commercial fryer is 12 years.[1]

Other Resource Impacts:

There are no other resource impacts for these measures.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b033	Electric Fryer, Standard Vat	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
E21C1b032	Electric Fryer, Large Vat	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
G21C1b024	Gas Fryer	LBES New	1.00	n/a	1.00	1.00	1.00	n/a	n/a
E21C1b033 E21C2b033 E21C3b050 E21C1c032 E21C2c032	Electric Fryer, Standard Vat	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b032 E21C2b032 E21C3b049 E21C1c031 E21C2c031	Electric Fryer, Large Vat	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b024 G21C2b024 G21C1c004 G21C2c004	Gas Fryer	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	1.00	1.00	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [2]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[3]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c032 E21C2c032	Electric Fryer, Standard Vat	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c031 E21C2c031	Electric Fryer, Large Vat	LBES Mid SBES Mid	0.225	0.085	0	0.86
G21C1c004 G21C2c004	Gas Fryer	LBES Mid SBES Mid	0.237	0.07	0	0.83

Energy Load Shape:

See Appendix 1 C&I Load Shapes, "C&I Food Services"

Endnotes:

1: SupportTable_EUL.csv, from DEER Database for Energy-Efficient Resources; Version 2016, READI v.2.4.3 (Current Ex Ante data) found at http://www.deeresources.com/

2: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

3: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.13 Food Service – Griddle

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Electric Griddle: Installation of a qualified ENERGY STAR electric griddle.

Gas Griddle: Installation of a qualified ENERGY STAR gas griddle.

ENERGY STAR griddles save energy cooking and idle times due to improved cooking efficiency and idle energy rates.

Baseline Efficiency:

Electric Griddle: The baseline efficiency case is a typically sized, (6 sq. ft.) electric, commercial griddle with a cooking energy efficiency, production capacity, and idle energy rate as defined by any applicable U.S. federal requirements.

Gas Griddle: The baseline efficiency case is a typically sized, (6 sq. ft.) gas, commercial griddle with a cooking energy efficiency, production capacity, and idle energy rate as defined by any applicable U.S. federal requirements.

High Efficiency:

Electric Griddle: The high efficiency case is a typically sized (6 sq. ft.), electric, commercial griddle with a cooking energy efficiency, production capacity, and idle energy rate meeting the minimum ENERGY STAR requirements.

Gas Griddle: The high efficiency case is a typically sized (6 sq. ft.), gas, commercial griddle with a cooking energy efficiency, production capacity, and idle energy rate meeting the minimum ENERGY STAR requirements.

Algorithms for Calculating Primary Energy Impact:

BC Measure ID	Measure Name	Program	ΔkW	ΔkWh	ΔMMBtu
E21C1b034 E21C2b034 E21C3b055 E21C1c033 E21C2c033	Commercial Electric Griddle	LBES New SBES New Muni LBES Mid SBES Mid	0.90	3,965	n/a

G21C1b025 G21C2b025 G21C1c005 G21C2c005	Commercial Gas Griddle	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	37.9

For electric Griddle:
$\Delta kWh = \Delta kWh$
$\Delta kW = \Delta kWh / Hours$

Where:
ΔkWh = gross annual kWh savings from the measure per table above
ΔkW = gross average kW savings from the measure per table above
Hours = annual operating hours

For Gas Griddle:
$\Delta MMBtu = MMBtu$

Where:
$\Delta MMBtu$ = gross annual MMBtu gas savings from the measure per table above.

Measure Life:

The measure life for a new commercial griddle is 12 years.[1]

Other Resource Impacts:

There are no other resource impacts for these measures.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b03	Electric Griddle	LBES New	1.00	.99	n/a	1.00	1.00	0.90	0.90
G21C1b025	Gas Griddle	LBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C1b034 E21C2b034 E21C3b055 E21C1c033 E21C2c033	Electric Griddle	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
G21C1b025 G21C2b025 G21C1c005 G21C2c005	Gas Griddle	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [2]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[3]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c033 E21C2c033	Electric Griddle	LBES Mid SBES Mid	0.225	0.085	0	0.86
G21C1c005 G21C2c005	Gas Griddle	LBES Mid SBES Mid	0.237	0.07	0	0.83

Energy Load Shape:

See Appendix 1 C&I Load Shapes, "C&I Food Services".

Endnotes:

1: SupportTable_EUL.csv, from DEER Database for Energy-Efficient Resources; Version 2016, READI v.2.4.3 (Current Ex Ante data) found at http://www.deeresources.com/

2: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

3: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.14 Food Service – Holding Cabinet

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Installation of a qualified ENERGY STAR hot food holding cabinet (HFHC). ENERGY STAR hot food holding cabinets are 70 percent more energy efficient than standard models. Models that meet this requirement incorporate better insulation, reducing heat loss, and may also offer additional energy saving devices such as magnetic door gaskets, auto-door closures, or Dutch doors. The insulation of the cabinet also offers better temperature uniformity within the cabinet from top to bottom. Offering full size, 3/4 size, and 1/2 size HFHC.

Baseline Efficiency:

The baseline efficiency idle energy rate for a HFHC is a unit meeting any applicable federal energy efficiency standards.

High Efficiency:

The high efficiency idle energy rate for HFHC is based on the product interior volume in cubic feet (V) as shown below. [1]

Size Category	Product Interior Volume, V (ft^3)	Product Idle Energy Consumption Rate (W)
Half size	$0 < V < 13$	≤ 21.5 V
3/4 size	$13 \leq V < 28$	≤ 2.0 V + 254.0
Full size	$28 \leq V$	≤ 3.8 V + 203.5

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed:

kWh = kWh
kW = kWh / Hours
Where:
kWh = gross annual kWh savings from the measure: See table below.
kW = gross average kW savings from the measure: See table below.
Hours = annual operating hours

Energy Savings for Commercial Hot Food Holding Cabinets

BC Measure ID	Measure Name	Program	ΔkW	ΔkWh
E21C1b037 E21C2b037 E21C3b058 E21C1c035 E21C2c035	Full Size	LBES New SBES New Muni LBES Mid SBES Mid	0.50	2,737
E21C1b036 E21C2b036 E21C3b057 E21C1c034 E21C2c034	3/4 Size	LBES New SBES New Muni LBES Mid SBES Mid	0.20	1,095
E21C1b038 E21C2b038 E21C3b059 E21C1c036 E21C2c036	1/2 Size	LBES New SBES New Muni LBES Mid SBES Mid	0.20	1,095

Measure Life:

The measure life for a new commercial HFHC is 12 years. [2]

Other Resource Impacts:

There are no other resource impacts for these measures.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b037	Hot Food Holding Cabinet Full Size	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
E21C1b036	Hot Food Holding Cabinet 3/4 Size	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
E21C1b038	Hot Food Holding Cabinet Half Size	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
E21C2b037 E21C3b058 E21C1c035 E21C2c035	Hot Food Holding Cabinet Full Size	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C2b036 E21C3b057 E21C1c034 E21C2c034	Hot Food Holding Cabinet 3/4 Size	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C2b038 E21C3b059 E21C1c036 E21C2c036	Hot Food Holding Cabinet Half Size	SBES New Muni LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90

In-Service Rates:

All installations have a 100% in-service rate since programs include verification of equipment installations.

Realization Rates:

100% Realization Rates are assumed because savings are based on researched assumptions by ENERGY STAR. . The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [3]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[4]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c035 E21C2c035	Hot Food Holding Cabinet Full Size	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c034 E21C2c034	Hot Food Holding Cabinet 3/4 Size	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c036 E21C2c036	Hot Food Holding Cabinet Half Size	LBES Mid SBES Mid	0.225	0.085	0	0.86

Energy Load Shape:

See Appendix 1 C&I Load Shapes, "C&I Food Services".

Endnotes:

1: ENERGY STAR Program Requirements Product Specification for Commercial Hot Food Holding Cabinets, Version 2.0. Effective October 1, 2011. https://www.energystar.gov/ia/partners/prod_development/revisions/downloads/hfhc/Final_V2.0_HFHC_Program_Requirements.pdf?b187-e770
2: FSTC Life Cycle Savings Calculators https://fishnick.com/saveenergy/tools/calculators/

3: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.15 Food Service – Hand-Wrap Machine

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an on-demand hand-wrap machine with Mechanical or optical control system. Food items, such as meat and cheese, are often placed on trays and wrapped in plastic film before being displayed for purchase. The plastic wrap protects the food from airborne organisms and dust, allows customers to view the product, and provides a surface for pasting information labels. A hand-wrap machine consists of a heating bar and a heating platform, rated at approximately 0.05 kW and 0.55 kW, respectively. The heating bar cuts the wrapping film as it comes in contact with itself. The heating platform heats up the wrapping film. When the wrapping film is heated, the film sticks to the package and seals the product.

Baseline Efficiency:

The baseline is defined as an always-on commercial electric hand-wrap machine.[1]

High Efficiency:

An efficient hand-wrap machine is defined as an on-demand model with a mechanical or optical control system. [1]

Algorithms for Calculating Primary Energy Impact:

Savings are deemed using the assumptions below:

BC ID	Measure Name	Program	ΔkWh[2]	ΔkW[2]
E21C1c051 E21C2c051	Hand-wrap Machine	LBES Mid SBES Mid	1,565	0.181

Assumptions:

Annual Energy					
Hand-Wrap Case	SUPERMARKET CHAIN 1 (kWh/yr)	SUPERMARKET CHAIN 2 (kWh/yr)	SUPERMARKET CHAIN 3 (kWh/yr)	SUPERMARKET CHAIN 4 (kWh/yr)	Annual Energy Consumption (kWh/yr)
Baseline	2,310.55	1,809.70	1,776.20	1,983.14	1,969.90
Efficient Case	411.64	395.10	452.30	361.21	405.06

Annual Energy					
Hand-Wrap Case	SUPERMARKET CHAIN 1 (kWh/yr)	SUPERMARKET CHAIN 2 (kWh/yr)	SUPERMARKET CHAIN 3 (kWh/yr)	SUPERMARKET CHAIN 4 (kWh/yr)	Annual Energy Consumption (kWh/yr)
Annual Savings	1898.91	1414.60	1323.90	1621.93	1564.84
Demand					
Hand-Wrap Case	SUPERMARKET CHAIN 1 (kW)	SUPERMARKET CHAIN 2 (kW)	SUPERMARKET CHAIN 3 (kW)	SUPERMARKET CHAIN 4 (kW)	Demand Savings (kW)
Baseline	0.267	0.227	0.201	0.229	0.231
Efficient Case	0.054	0.043	0.059	0.043	0.050
Annual Savings	0.21	0.18	0.14	0.19	0.181

Measure Life:

The measure life for a hand-wrap machine is 10 years. [3]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c051 E21C2c051	Hand-wrap Machine	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[5]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes “LS_111 C&I Food Service”

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[4]	SO_P[4]	SO_{NP}[4]	NTG[4]
E21C1c051 E21C2c051	Hand-wrap Machine	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: Southern California Edison (SCE), Emerging Products. 2015. Commercial Hand Wrap Machines for Food Service Applications Field Test. ET13SCE1190. https://www.caetrm.com/media/reference-documents/SCE_2014_ET13SCE1190_Report.pdf
2: Southern California Edison (SCE). 2016. “SCE17CC014.0 Com Hand Wrap Machines Costs 2016.xlsx.” https://www.caetrm.com/media/reference-documents/SCE17CC014.0_Com_Hand_Wrap_Machines_Costs_2016.xlsx
3: University of California, Office of the President, Purchasing Services. 2018. "Useful Life Index, G8605: Cutters, Slicers, Saws, Choppers, Graters, Grinders, Universal Mach, Food Prep." Download https://www.caetrm.com/media/reference-documents/UC_EUL_for_Hand_Wrap_Food_Prep_2018.pdf
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors’ Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52
5: SoCalGas, 2019. “WPSCGNRCC171226A – Commercial Conveyor Broilers” Revision 01.

Revision Number	Date	Revision
62	3/1/2022	New Measure Added

2.16 **Food Service – High Efficiency Condensing Unit**

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an efficient condensing unit defined as having three requisite attributes: an efficient scroll compressor, floating head pressure controls, and modulating compressor fan speed capabilities.. The collective effect of these three features results in the refrigeration load requirements being met while using less power as compared to a baseline unit.

Baseline Efficiency:

A baseline condensing unit is one with a standard compressor efficiency rating (as defined and established by Efficiency Vermont's Refrigeration Analysis Tool), no floating head pressure controls, and single speed compressor fan motors.[1]

High Efficiency:

An efficient condensing unit is defined by units incorporating three requisite attributes: an efficient scroll compressor, floating head pressure controls, and modulating compressor fan speed capabilities.[1]

Algorithms for Calculating Primary Energy Impact:

Deemed savings will be claimed based on a unit's temperature application, power phase requirements and compressor horsepower rating. The prescriptive, deemed savings in the table below are based on linear interpolation and extrapolation of currently available data from the 2018 Vermont TRM. [1]

BC ID	Program	HECU Type	Single Phase Low Temp		Single Phase Medium Temp		Three Phase Low Temp		Three Phase Medium Temp	
E21C1c052 E21C2c052	LBES Mid SBES Mid Muni	HP	ΔkW	ΔkWh	ΔkW	ΔkWh	ΔkW	ΔkWh	ΔkW	ΔkWh
		1	0.283	1,112	0.426	2,239	0.210	992	0.341	1,854
		1.5	0.333	1,612	0.400	2,237	0.269	1,413	0.354	2,014
		2	0.384	2,285	0.467	2,2609	0.329	2,003	0.413	2,349
		2.5	0.422	2,579	0.547	3,056	0.382	2,356	0.483	2,751
		3	0.471	2,878	0.641	3,730	0.426	2,629	0.563	3,282
		3.5	0.570	3,483	0.781	4,399	0.516	3,182	0.694	3,907
		4	0.583	3,528	0.864	4,865	0.557	3,450	0.769	4,321
		4.5	0.618	3,802	0.879	4,952	0.611	3,718	0.783	4,398
		5	0.683	4,240	0.829	4,904	0.673	4,416	0.805	4,678
		6	0.783	5,083	0.829	4,904	0.788	4,979	0.805	4,678

Measure Life:

The measure life for a HECU is 13 years. [1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c052 E21C2c052	High Efficiency Condensing Unit	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[3]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "LS_111 C&I Food Service"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[2]	SO_P[2]	SO_{NP}[2]	NTG[2]
E21C1c052 E21C2c052	High Efficiency Condensing Unit	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: Efficiency Vermont (2018), "Technical Reference User Manual (TRM); Measure Savings Algorithms and Cost Assumptions" https://puc.vermont.gov/document/ev-technical-reference-manual
2: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52
3: SoCalGas, 2019. "WPSCGNRCC171226A – Commercial Conveyor Broilers" Revision 01.

Revision Number	Date	Revision
63	3/1/2022	New Measure Added

2.17 Food Service – Ice Machine

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Installation of a qualified ENERGY STAR commercial ice machine. Commercial ice machines meeting the ENERGY STAR specifications are on average 15 percent more energy efficient and 10 percent more water-efficient than standard models. ENERGY STAR qualified equipment includes ice-making head (IMH), self-contained (SCU), and remote condensing units (RCU).

Baseline Efficiency:

The baseline efficiency case is a non-ENERGY STAR commercial ice machine, which must be compliant with the applicable federal standard.[1]

High Efficiency:

The high efficiency case is a commercial ice machine meeting the ENERGY STAR V3.0 Efficiency Requirements for commercial ice machines.

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated on a per-unit basis, based on the equipment type and daily ice harvest rate.

$$\Delta kWh = units\ x\ (kWh_{baseline} - kWh_{ee})\ x\ 365\ x\ Cycle\ x\ \left(\frac{IHR}{100}\right)$$

$$\Delta kW = \frac{\Delta kWh}{8{,}760\ x\ Cycle}\ x\ CF$$

Where:
ΔkWh = Annual electric energy savings
ΔkW = Peak coincident demand electric savings
units = Number of measures installed under the program
baseline = Baseline condition or measure
ee = Energy efficient condition or measure
kWh = Daily electric energy consumption per 100 pounds of ice
Cycle = Compressor duty cycle [2] = .75
IHR = Ice Harvest Rate (lbs/day) of the energy efficient ice maker.
CF = Coincidence factor
365 = Days in one year

100 = Factor to convert IHR to units of 100 lbs/day
8,760 = Hours in one year

The baseline condition is a non-ENERGY STAR commercial ice machine, which must be compliant with the applicable federal standard updated January 28, 2018.[1] The baseline daily energy usage per 100 pounds of ice is established in accordance with the current federal energy standards as specified in the Code of Federal Energy Regulations, updated January 28, 2018 .

Baseline Efficiency Inputs for Automatic Ice Machines[1]:

Cooling	Equipment Type	IHR	Maximum energy use kWh/100 lb ice[1]
	Continuous Type		
Air	Ice-Making Head	<310	9.19-0.00629H
	Ice-Making Head	≥310 and <820	8.23-0.0032H
	Ice-Making Head	≥820 and <4,000	5.61
Air	Remote Condensing (no remote compressor)	<800	9.7-0.0058H
	Remote Condensing (no remote compressor)	≥800 and <4,000	5.06
	Remote Condensing & Remote Compressor	<800	9.9-0.0058H
Air	Self-Contained	<200	14.22-0.03H
	Self-Contained	≥200 and <700	9.47-0.00624H
	Self-Contained	≥700 and <4,000	5.1
	Batch Type		
Air	Ice-Making Head	< 300	10-0.01233H
	Ice-Making Head	≥ 300 and < 800	7.05-0.0025H
	Ice-Making Head	≥ 800 and < 1,500	5.55-0.00063H
	Ice-Making Head	≥ 1500 and < 4,000	4.61
Air	Remote Condensing (no remote compressor)	< 988	7.97-0.00342H
	Remote Condensing (no remote compressor)	≥ 988 and < 4,000	4.59
	Remote Condensing & Remote Compressor	< 930	7.97-0.00342H
	Remote Condensing & Remote Compressor	≥ 930 and < 4,000	4.79
Air	Self-Contained	< 110	14.79-0.0469H
	Self-Contained	≥ 110 and < 200	12.42-0.02533H
	Self-Contained	≥ 200 and < 4,000	7.35

The high efficiency condition is commercial ice machine meeting the ENERGY STAR V3.0 Efficiency Requirements for commercial ice machines. Efficient daily energy use per 100 pounds of ice is established based on efficient equipment Ice Harvest Rate in accordance with ENERGY STAR® maximum qualifying specifications.

Energy Efficient Inputs for Automatic Commercial Ice Machines [3]

BC Measure ID	Program	Equipment Type	IHR	Maximum energy use kWh/100 lb ice[1]
	Continuous Type			
E21C1b039 E21C2b039 E21C3b060 E21C1c037 E21C2c037	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air cooled Ice-Making Head	H < 310	7.90 – 0.005409H
		Air cooled Ice-Making Head	310 ≤ H < 820	7.08 – 0.002752H
		Air cooled Ice-Making Head	820 ≤ H ≤ 4000	4.82
E21C1b042 E21C2b042 E21C3b063 E21C1c040 E21C2c040	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air Cooled Remote Condensing Unit	H < 800	7.76 – 0.00464H
		Air Cooled Remote Condensing Unit	800 ≤ H ≤ 4000	4.05
E21C1b040 E21C2b040 E21C3b061 E21C1c038 E21C2c038	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air Cooled Self-Contained	H<200	12.37 – 0.0261H
		Air Cooled Self-Contained	200 ≤ H ≤ 700	8.24 – 0.005429H
		Air Cooled Self-Contained	700 ≤ H ≤ 4000	4.44
	Batch Type			
	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air cooled Ice-Making Head	H<300	9.20 - 0.01134H
		Air cooled Ice-Making Head	300 ≤ H < 800	6.49 - 0.0023H
		Air cooled Ice-Making Head	800 ≤ H < 1,500	5.11 - 0.00058H
		Air cooled Ice-Making Head	1,500 ≤ H ≤ 4000	4.24
E21C1b041 E21C2b041 E21C3b062 E21C1c039 E21C2c039	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air Cooled Remote Condensing Unit	H < 988	7.17 – 0.00308H
		Air Cooled Remote Condensing Unit	988 ≤ H ≤ 4000	4.13
	LBES NEW SBES NEW MUNI NEW LBES MID SBES MID	Air Cooled Self-Contained	H<110	12.57 - 0.0399H
		Air Cooled Self-Contained	110 ≤ H ≤ 200	10.56 - 0.0215H
		Air Cooled Self-Contained	200 ≤ H ≤ 4000	6.25

Measure Life:

The measure life for a new ice making machine is 8 years. [2]

Other Resource Impacts:

Water savings associated with this measure are calculated using on the Energy Star Commercial Food Service Calculator, updated in March 2021[4]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b039	Ice Machine - Ice Making Head	LBES New	1.00	0.99	n/a	1.00	1.00	0.9	0.9
E21C1b040	Ice Machine - Remote Cond./Split Unit - Batch	LBES New	1.00	0.99	n/a	1.00	1.00	0.9	0.9
E21C1b041	Ice Machine - Remote Cond./Split Unit - Continuous	LBES New	1.00	0.99	n/a	1.00	1.00	0.9	0.9
E21C1b042	Ice Machine - Self Contained	LBES New	1.00	0.99	n/a	1.00	1.00	0.9	0.9
E21C2b039 E21C3b060 E21C1c037 E21C2c037	Ice Machine - Ice Making Head	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.9	0.9
E21C2b040 E21C3b061 E21C1c038 E21C2c038	Ice Machine - Remote Cond./Split Unit - Batch	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.9	0.9
E21C2b041 E21C3b062 E21C1c039 E21C2c039	Ice Machine - Remote Cond./Split Unit - Continuous	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.9	0.9
E21C2b042 E21C3b063 E21C1c040 E21C2c040	Ice Machine - Self Contained	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.9	0.9

In-Service Rates:

All installations have 100% in service rate since programs include verification of equipment installations.

Realization Rates:

100% realization rates are assumed because savings are based on researched assumptions. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [5]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[6]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c037 E21C2c037	Ice Machine - Ice Making Head	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c038 E21C2c038	Ice Machine - Remote Cond./Split Unit - Batch	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c039 E21C2c039	Ice Machine - Remote Cond./Split Unit - Continuous	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c040 E21C2c040	Ice Machine - Self Contained	LBES Mid SBES Mid	0.225	0.085	0	0.86

Energy Load Shape:

See Appendix 1 "C&I Load Shapes, "C&I Food Services".

Endnotes:

1: 10 CFR 431.136. Effective January 28, 2018, https://www.ecfr.gov/cgi-bin/text-idx?node=se10.3.431_1136&rgn=div8
2: FOOD SERVICE COMMERCIAL ICE MACHINE. SWFS006-01. (CA) December 2018. http://www.deeresources.net/workpapers
3: ENERGY STAR Program Requirements For Automatic Commercial Ice Makers. V3.0. https://www.energystar.gov/products/commercial_food_service_equipment/commercial_ice_makers/key_product_criteria
4: ENERGY STAR CFS Calculator, March 2021 https://cmadmin.energystar.gov/sites/default/files/asset/document/CFS_calculator_03-02-2021.xlsx
4: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf
5: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52) https://ma-eeac.org/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf
6: Itron, Inc. 2005. 2004-2005 Database for Energy Efficiency Resources (DEER) Update Study - Final Report. Prepared for Southern California Edison.

Revision Number	Date	Revision
43	1/14/2022	Corrected algorithms to provide annualized savings, updated baselines
44	1/14/2022	Added other resource impacts.

2.18 Food Service – Oven

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Combination Oven, Electric Convection Oven, Electric	Installation of a qualified ENERGY STAR commercial convection oven or commercial combination oven. ENERGY STAR commercial ovens save energy during preheat, cooking and idle times due to improved cooking efficiency, and preheat and idle energy rates. Combination ovens can be used either as convection ovens or as steamers.

Combination Oven, Gas Convection Oven, Gas Conveyor Oven, Gas Rack Oven, Gas	Installation of High Efficiency Gas Ovens

Baseline Efficiency:

The baseline efficiency case is a convection, combination, conveyor, or rack oven that meets applicable minimum federal efficiency standards and uses the same fuel as the proposed high efficiency equipment.

High Efficiency:

The high efficiency case is a commercial oven that meets the ENERGY STAR program requirements for its type and fuel, as shown below.[1] Note that combination ovens are rated based on their capacity in number of pans (P), and that no ENERGY STAR program requirements for conveyor ovens have yet been approved.

Oven Fuel	Measure Name	Efficiency Requirement	Idle rate
Electric	Convection Oven	≥ 71%	≤ 1.60 kW
Electric	Combination Oven	≥ 55% steam mode ≥ 76% convection mode	≤ 0.133P+0.6400 kW steam mode ≤ 0.080P+0.4989 kW convection mode
Gas	Convection Oven	≥ 46%	≤ 12,000 Btu/hr
Gas	Combination Oven	≥ 41% steam mode ≥ 56% convection mode	≤ 200P + 6,511 Btu/hr steam mode ≤ 150P + 5,425 Btu/hr convection mode

Gas	Conveyer Oven		
Gas	Rack Oven	≥ 48%	≤ 25,000 Btu/hr

Ovens must be rated based on ASTM F1496 (Convection Oven), ASTM F2861 (Combination Oven), and ASTM 2093 (Conveyor Oven and Rack Oven).

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed.

ΔkWh = kWh
ΔkW = kWh / hours
ΔMMBtu = MMBtu

Where:
ΔkWh = gross annual kWh savings from the measure. See table below.
ΔkW = gross average kW savings from the measure. See table below.
ΔMMBtu = gross average natural gas savings from the measure. See table below.
Hours = Annual hours of operation = 4,390 hr/yr at 12 hr/day

Energy Savings for Commercial Ovens

BC Measure ID	Measure Name	Program	ΔkW	ΔkWh	ΔMMBtu
E21C1b021 E21C2b021 E21C3b035	Electric Full Size Convection Oven	LBES New SBES New Muni New LBES Mid SBES Mid	0.70	2,787	n/a
E21C1b019 E21C2b019 E21C3b031	Electric Combination Oven	LBES New SBES New Muni New LBES Mid SBES Mid	3.50	15,095	n/a
G21C1b022 G21C2b022 G21C1c002 G21C2c002	Gas Convection Oven	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	35.7
G21C1b021 G21C2b021 G21C1c001 G21C2c001	Gas Combination Oven	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	110.3
G21C1b023 G21C2b023 G21C1c003 G21C2c003	Gas Conveyer Oven	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	88.4

G21C1b026 G21C2b026 G21C1c007 G21C2c007	Gas Rack Oven	LBES New **SBES New** LBES Mid SBES Mid	n/a	n/a	211.3

Measure Life:

The measure life for a new commercial oven is 12 years. [2]

Other Resource Impacts:

There are no other resource impacts for these measures.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b021	Electric Convection Oven	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
E21C1b019	Electric Combination Oven	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
G21C1b022	Gas Convection Oven	LBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1b021	Gas Combination Oven	LBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1b023	Gas Conveyer Oven	LBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1b026	Gas Rack Oven	LBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C1b021 E21C2b021 E21C3b035 E21C1c019 E21C2c019	Electric Convection Oven	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
E21C1b019 E21C2b019 E21C3b031 E21C1c018 E21C2c018	Electric Combination Oven	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
G21C1b022 G21C2b022 G21C1c002 G21C2c002	Gas Convection Oven	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1b021 G21C2b021 G21C1c001	Gas Combination Oven	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C2c001									
G21C1b023 G21C2b023 G21C1c003 G21C2c003	Gas Conveyer Oven	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1b026 G21C2b026 G21C1c007 G21C2c007	Gas Rack Oven	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have 100% in service rate since programs include verification of equipment installations

Realization Rates:

Installations have a 100% realization rate because programs use researched values for savings estimates. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [3]

Coincidence Factors:

Coincidence Factors for electric ovens are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[4]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c019 E21C2c019	Electric Convection Oven	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c018 E21C2c018	Electric Combination Oven	LBES Mid SBES Mid	0.225	0.085	0	0.86
G21C1c002 G21C2c002	Gas Convection Oven	LBES Mid SBES Mid	0.237	0.07	0	0.83
G21C1c001 G21C2c001	Gas Combination Oven	LBES Mid SBES Mid	0.237	0.07	0	0.83
G21C1c003 G21C2c003	Gas Conveyer Oven	LBES Mid SBES Mid	0.237	0.07	0	0.83
G21C1c007 G21C2c007	Gas Rack Oven	LBES Mid SBES Mid	0.237	0.07	0	0.83

Energy Load Shape:

See Appendix 1"C&I Load Shapes, "C&I Food Services".

Endnotes:

1: ENERGY STAR Program Requirements for Commercial Ovens. Version 2.2. https://www.energystar.gov/sites/default/files/Commercial%20Ovens%20Final%20Version%202.2%20Specification.pdf
2: FSTC Life Cycle Savings Calculators https://fishnick.com/saveenergy/tools/calculators/**3:** DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.19 Food Service – Steam Cooker

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Electric Steam Cooker: Installation of a qualified ENERGY STAR commercial steam cooker. ENERGY STAR steam cookers save energy during cooling and idle times due to improved cooking efficiency and idle energy rates.

Gas Steam Cooker: The installation of an ENERGY STAR rated natural-gas fired steamer, either connectionless or steam-generator design. Qualified steamers reduce heat loss due to better insulation, improved heat exchange, and more efficient steam delivery systems.

Baseline Efficiency:

Electric Steam Cooker: The Baseline Efficiency case is an electric steam cooker with a cooking efficiency, pan production capacity, preheat energy, and idle energy rate as defined by any relevant U.S. federal requirements.

Gas Steam Cooker: The baseline efficiency case is a gas steam cooker with a cooking efficiency, pan production capacity, preheat energy, and idle energy rate as defined by any relevant U.S. federal requirements.

High Efficiency:

Electric Steam Cooker: The High Efficiency case is an electric steam cooker with a cooking energy efficiency, pan production capacity, preheat energy, and an idle energy rate meeting the minimum ENERGY STAR requirements.

Gas Steam Cooker: The high efficiency case is a gas steam cooker with a cooking energy efficiency, pan production capacity, preheat energy, and an idle energy rate meeting the minimum ENERGY STAR requirements.

Algorithms for Calculating Primary Energy Impact:

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW	ΔMMBtu
E21C1b048 E21C2b048 E21C3b079 E21C1c043 E21C2c043	Electric Steam Cooker	LBES New SBES New Muni New LBES Mid SBES Mid	30,156	6.89	n/a

G21C1b027 G21C2b027 G21C1c008 G21C2c008	Gas Steam Cooker	LBES New SBES New LBES Mid SBES Mid	n/a	n/a	370.7

Quantity = Number of pans
Hours = Average annual equipment operating hours. See Hours section below.

Measure Life:

The measure life for a new steamer is 12 years.[1]

Other Resource Impacts:

Electric Steam Cooker: Deemed annual water savings.

Gas Steam Cooker: Deemed annual water savings.[2]

Measure Name	Annual water savings (gal/unit)
Gas Steam Cooker	162,060

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b048	Electric Steam Cooker	LBES New	1.00	0.99	n/a	1.00	1.00	0.90	0.90
G21C1b027	Gas Steam Cooker	LBES New	1.00	n/a	1.00	1.00	1.00	n/a	n/a
E21C2b048 E21C3b079 E21C1c043 E21C2c043	Electric Steam Cooker	SBES New Muni New LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	0.90	0.90
G21C2b027 G21C1c008 G21C2c008	Gas Steam Cooker	SBES New LBES Mid SBES Mid	1.00	n/a	1.00	1.00	1.00	n/a	n/a

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [3]

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.

Energy Load Shape:

See Appendix 1 See Appendix 1"C&I Load Shapes, "C&I Food Services".

Endnotes:

1: SupportTable_EUL.csv, from DEER Database for Energy-Efficient Resources; Version 2016, READI v.2.4.3 (Current Ex Ante data) found at http://www.deeresources.com/
2: ENERGY STAR Commercial Kitchen Equipment Calculator. Updated October 2016. https://www.energystar.gov/buildings/sites/default/uploads/files/commercial_kitchen_equipment_calculator.xlsx
3: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.20 Food Service – Refrigerator

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Installation of a qualified ENERGY STAR qualified reach-in refrigerator that replaces a standard efficiency unit of the same configuration and capacity. The refrigerator may have a solid door or transparent door. Measure savings are defined by configuration and internal volume as specified in the Energy Star commercial requirements presented below.

Baseline Efficiency:

The baseline case includes standard-efficiency, reach-in solid and transparent door refrigerators and are defined by the U.S. Department of Energy (DOE) federal requirements.

High Efficiency:

The high efficiency case is an ENERGY STAR qualified reach-in refrigerator having the same configuration and capacity as the baseline equipment.

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated and based on the Energy Star Commercial Kitchen Equipment Calculator.

$$\Delta kWh = kWh_{BL} - kWh_{EE}$$
$$kWh_{BL} = (kWh_D)_{BL} \times D$$
$$kWh_{EE} = (kWh_D)_{EE} \times D$$

Where,
ΔkWh = Annual electric energy savings (kWh)
kWh_{BL} = Annual electric energy consumption of baseline equipment (kWh). Calculate from table below.
kWh_{EE} = Annual electric energy consumption of efficient equipment (kWh). Calculate from table below.
kWh_D = Daily electric energy consumption (kWh)
D = Number of days of operation of the unit. Use site specific data if possible (365 days is default).
V = Internal volume of equipment (ft^3)

Equipment Daily Consumption[1,2]

Door Type	Size Thresholds	Baseline Refrigerator Daily Energy Consumption $(kWh_D)_{BL}$	Efficient Refrigerator Daily Energy Consumption $(kWh_D)_{EE}$
Solid Door	0 < V < 15	(0.05 x V) + 1.36	(0.022 x V) + 0.97
	15 < V < 30		(0.066 x V) + 0.31

	30 < V < 50		(0.04 x V) + 1.09
	50 < V		(0.024 x V) + 1.89
Transparent Door	0 < V < 15	(0.1 x V) + 0.86	(0.095 x V) + 0.445
	15 < V < 30		(0.05 x V) + 1.12
	30 < V < 50		(0.076 x V) + 0.34
	50 < V		(0.105 x V) - 1.111

Measure Life[3]:

BC Measure ID	Measure Name	Program	Measure Life
E21C1c041 E21C2c041	Refrigerator, Transparent Door	LBES Mid SBES Mid	12
E21C1c042 E21C2c042	Refrigerator, Solid Door	LBES Mid SBES Mid	12

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c041 E21C2c041	Refrigerator, Transparent Door	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C1c042 E21C2c042	Refrigerator, Solid Door	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	1.00	1.00

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

All programs use a 100% coincidence factor unless an evaluation finds otherwise.

Energy Load Shape:

See Appendix 1

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[4]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c041 E21C2c041	Refrigerator, Transparent Door	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c042 E21C2c042	Refrigerator, Solid Door	LBES Mid SBES Mid	0.225	0.085	0	0.86

Future application of measure-specific NEI values will be considered by the NH Benefit/Cost (B/C) Working Group, per Commission Order No. 26,323 , December 31, 2019.

Endnotes:
1: Efficient equipment daily energy consumption is in line with ENERGY STAR. 2016. "ENERGY STAR® Program Requirements Product Specification for Commercial Refrigerators and Freezers - Eligibility Criteria Version 4.0." Effective on March 27, 2017.
2: Baseline equipment daily energy consumption is defined by the U.S. Department of Energy (DOE) federal requirements. Code of Federal Regulations at 10 CFR 431.66.
3: California Public Utilities Commission (CPUC), Energy Division. 2014. "DEER2014-EUL-table-update_2014-02-05.xlsx."
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover S

2.21 Food Service – Refrigerated Chef Bases

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an efficient refrigerated chef base. Refrigerated chef bases are found in almost all commercial kitchens. A refrigerated chef base is used to keep ingredients or prepared meals close to the cooking station, making food preparation more efficient. The capacity or size of a chef base is represented by its exterior length (feet), ranging from approximately three feet to about ten feet. The refrigerated compartment can be equipped with drawers or doors according to customer specifications.

Baseline Efficiency:

The baseline condition is defined as a refrigerated chef base which uses more energy than the high efficiency case specified for the equivalent exterior length, in the table below:

Baseline Efficiencies[1]:

Exterior Length (inches)	Daily Energy Use Intensity (kWh/day/ ft^3)
35-54	0.6000
55-73	0.5400
74-89	0.4751
90-120	0.4694

High Efficiency:

The high efficiency case is defined as a refrigerated chef base that uses energy less than or equal to the maximum daily energy consumption specified in the table below:

High Efficiencies[1]:

Exterior Length (inches)	Daily Energy Use Intensity (kWh/day/ft^3)
35-54	0.1785
55-73	0.1600
74-89	0.1408
90-120	0.1391

Algorithms for Calculating Primary Energy Impact:

Deemed Savings:

BC ID	Measure Name	Program	ΔkWh/ year[3]	ΔkW[3]
E21C1c053	Refrigerated Chef Base 35-54 inches	LBES Mid SBES Mid	1,052	.1152

E21C1c053	Refrigerated Chef Base 55-73 inches	LBES Mid SBES Mid	1,637	.177
E21C1c053	Refrigerated Chef Base 74-89 inches	LBES Mid SBES Mid	1,985	.2142
E21C1c053	Refrigerated Chef Base 90-120 inches	LBES Mid SBES Mid	2,673	.2885

Savings Algorithms[3]:

$$\Delta kWh = \left(\frac{base\ kwh/day}{ft^3} - \frac{measure\ kwh/day}{ft^3}\right) \times constRef_{Vol} \times\ const_{opDaysyr}$$

$$\Delta kW = \left(\frac{Base\ kW}{ft^3} - \frac{measure\ kW}{ft^3}\right) \times c\ onstRef_{Vol}$$

Where:
Base kwh/day/ft^3 = Baseline efficiency daily energy use intensity
Measure kwh/day/ ft^3 = High efficiency daily energy use intensity
$ConstRef_{vol}$= refrigerated volume (ft^3)
$Const_{opsDaysyr}$= 365 annual days of operation

Measure Life:

The measure life for a refrigerated chef base is 12 years. [2]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c053	Refrigerated Chef Base 35-54 inches	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	.90	.90
E21C1c053	Refrigerated Chef Base 55-73 inches	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	.90	.90
E21C1c053	Refrigerated Chef Base 74-89 inches	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	.90	.90
E21C1c053	Refrigerated Chef Base 90-120 inches	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	.90	.90

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[5]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "LS_109 C&I Refrigeration"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[4]	SO_P[4]	SO_{NP}[4]	NTG[4]
E21C1c053	Refrigerated Chef Base 35-54 inches	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c053	Refrigerated Chef Base 55-73 inches	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c053	Refrigerated Chef Base 74-89 inches	LBES Mid SBES Mid	0.225	0.085	0.0	0.86
E21C1c053	Refrigerated Chef Base 90-120 inches	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:

1: Southern California Edison (SCE), Emerging Products. 2016. Chef Bases for Foodservice Applications. ET15SCE1010 Report. August. https://www.caetrm.com/media/reference-documents/ET15SCE1010_Chef_Bases_Report_final2.pdf
2: California Public Utilities Commission (CPUC), Energy Division. 2014. "DEER2014-EUL-table-update_2014-02-05.xlsx" https://www.caetrm.com/media/reference-documents/DEER2014-EUL-table-update_2014-02-05_PUq4NzL.xlsx
3: Southern California Edison (SCE). 2019. "SWFS016-01 – Savings and Cost Analysis.xlsx." https://www.caetrm.com/media/reference-documents/SWFS016-01_Savings_and_Cost_Analysis.xlsx
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)
5: SoCalGas, 2019. "WPSCGNRCC171226A – Commercial Conveyor Broilers" Revision 01.

Revision Number	Date	Revision
59	3/1/2022	New Measure Added

tudy, Aug. 14, 2018 (Table 48, Table 52)

2.22 Food Service – Freezer

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Food Service

Description:

Installation of a qualified ENERGY STAR qualified reach-in freezer that replaces a standard efficiency unit of the same configuration and capacity. The freezer may have a solid door or transparent door. Measure savings are defined by configuration and internal volume as specified in the ENERGY STAR commercial requirements presented below.

Baseline Efficiency:

The baseline case includes standard-efficiency, reach-in, solid and transparent door freezers and are defined by the U.S. Department of Energy (DOE) federal requirements.

High Efficiency:

The high efficiency case is an ENERGY STAR qualified reach-in freezer having the same configuration and capacity as the baseline equipment .

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated and based on the ENERGY STAR Commercial Kitchen Equipment Calculator.

$$\Delta kWh = kWh_{BL} - kWh_{EE}$$
$$kWh_{BL} = (kWh_D)_{BL} \times D$$
$$kWh_{EE} = (kWh_D)_{EE} \times D$$

Where,
ΔkWh = Annual electric energy savings (kWh)
kWh_{BL} = Annual electric energy consumption of baseline equipment (kWh). Calculate from table below.
kWh_{EE} = Annual electric energy consumption of efficient equipment (kWh). Calculate from table below.
kWh_D = Daily electric energy consumption (kWh)
D = Number of days of operation of the unit. Use site specific data if possible (365 days is default).
V = Internal volume of equipment (ft^3)

Equipment Daily Consumption[1,2]

Door Type	Size Thresholds	Baseline Freezer Daily Energy Consumption $(kWh_D)_{BL}$	Efficient Freezer Daily Energy Consumption $(kWh_D)_{EE}$
Solid Door	0 < V < 15	(0.22 x V) + 1.38	(0.021 x V) + 0.90

	15 < V < 30		(0.012 x V) + 2.248
	30 < V < 50		(0.285 x V) - 2.703
	50 < V		(0.142 x V) + 4.445
Transparent Door	All	(0.29 x V) + 2.95	(0.232 x V) + 2.36

Measure Life[3]:

BC Measure ID	Measure Name	Measure Life
E21C1c030 E21C2c030	Freezer, Transparent Door	12
E21C1c029 E21C2c029	Freezer, Solid Door	12

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c030 E21C2c030	Freezer, Transparent Door	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C1c029 E21C2c029	Freezer, Solid Door	LBES Mid SBES Mid	1.00	1.00	n/a	1.00	1.00	1.00	1.00

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

All programs use a 100% coincidence factor unless an evaluation finds otherwise.

Energy Load Shape:

See Appendix 1 C&I Load Shapes “C&I Food Service”.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[4]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c030 E21C2c030	Freezer, Transparent Door	LBES Mid SBES Mid	0.225	0.085	0	0.86
E21C1c029 E21C2c029	Freezer, Solid Door	LBES Mid SBES Mid	0.225	0.085	0	0.86

Endnotes:
1: Efficient equipment daily energy consumption is in line with ENERGY STAR. 2016. "ENERGY STAR® Program Requirements Product Specification for Commercial Refrigerators and Freezers - Eligibility Criteria Version 4.0." Effective on March 27, 2017.
2: Baseline equipment daily energy consumption is defined by the U.S. Department of Energy (DOE) federal requirements. Code of Federal Regulations at 10 CFR 431.66.
3: California Public Utilities Commission (CPUC), Energy Division. 2014. "DEER2014-EUL-table-update_2014-02-05.xlsx."
4: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52)

2.23 Food Service – Ultra Low-Temp Freezer

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an ENERGY STAR qualified ultra low temp freezer to replace a standard efficiency ULT freezer with a standard efficiency dual cascade refrigeration system.

Baseline Efficiency:

The baseline technology is a standard efficiency ULT freezer with a standard efficiency dual cascade refrigeration system.[1]

High Efficiency:

The high efficiency case is ENERGY STAR qualified under the Ultra Low Temperature Freezer Specification.[2]

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on vendor data from ULT freezers offered in MA and the 2017 DMI ULT Base Case Investigation.[1,3]

BC ID	Measure Name	ΔkWh	ΔkW
	ULT Freezer	5,737	0.654

Measure Life:

The measure life for a ULT Freezer base is 15 years.[1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
	ULT Freezer	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[5]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "LS_109 C&I Refrigeration"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[4]	SO_P[4]	SO_{NP}[4]	NTG[4]
	ULT Freezer	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: Eversource Energy ULT Freezer Base Case Investigation, prepared by DMI, October 7, 2017
2: EnergyStar (2016) "Laboratory Grade Refrigerators & Freezers Specification" https://www.energystar.gov/products/other/laboratory_grade_refrigerators_and_freezers
3: Energy Solutions (2021) "Cold Storage Forecast Assumptions"
4: Conservative estimate based on manufacturer's EUL of 20 years.
NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52
5: SoCalGas, 2019. "WPSCGNRCC171226A – Commercial Conveyor Broilers" Revision 01.

Revision Number	Date	Revision
64	3/1/2022	New Measure Added

2.24 Food Service – Underfired Broilers

Measure Code	TBD
Market	Commercial and Industrial
Program Type	New Construction, Retrofit
Category	Food Service

Description:

Installation of an efficient underfired broiler with an input rate ≤ 22 kBtu/hr/len-ft while maintaining a surface temperature of 600 °F. An underfired broiler is composed of a heavy-duty cooking grate suspended above a radiant heat source. Below the grate is a set of atmospheric burners spaced every four to twelve inches along the width of the broiler, covered by a protective radiant material.

Baseline Efficiency:

The baseline is defined as underfired broiler with an input rate greater than 22 Kbtu/hr/ln-ft at 600 degrees F, and an idle and cooking energy rate of 25,000.00. [1]

High Efficiency:

The high efficiency case is defined as an underfired broiler with an input rate of less than 22 kbtu/hr at 600 degrees F and an idle and cooking energy of less than or equal to 20,000 as specified per the ASTM F1695 standard[2], and of similar size to the replacement unit.

Algorithms for Calculating Primary Energy Impact:

Deemed Savings[3]:

BC ID	Measure Name	Δtherms
	Underfired broiler	217.8

Δ Therms = (base_idlebtuh_ft – Measure_idlebtuh_ft) x opHr_day*Op_Day

Where:
base_idlebtuh_ft = idle energy rate, baseline (btu/hr)
measure_idlebtuh = idle energy rate, efficient (btu/hr)
opHr_day = operating hours per day
op_Day = operating days per year

Inputs and Assumptions[4]:

Description	Standard Model	Efficient Model
Preheat Time (min)	30	30
Broiler Idle Energy Rate (Btuh)	25,000	20,000
Broiler Production Capacity (lb/h)	25	20
Operating Hours/Day	12	12

Operating Days/Year	363	363

Measure Life:

The measure life for an underfired broiler is 15 years.[1]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
	Underfired Broiler	LBES Mid SBES Mid	1.00	1.00	1.00	1.00	1.00	.90	.90

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence Factors are 0.9 for both summer and winter seasons to account for the fact that some restaurants close one day per week and some may not serve both lunch and dinner on weekdays.[5]

Other Resource Impacts:

There are no other resource impacts for this measure.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "LS_109 C&I Refrigeration"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):

BC Measure ID	Measure Name	Program	FR[6]	SO_P[6]	SO_{NP}[6]	NTG[6]
	Underfired Broiler	LBES Mid SBES Mid	0.225	0.085	0.0	0.86

Endnotes:
1: Fisher-Nickel, Inc. 2014. Emerging Technologies (ET) Lidded Thermostatic Infrared Broiler Field Study. Emerging Technologies project ET13PGE1311. Prepared for Pacific Gas and Electric Company (PG&E). December 15.
https://www.caetrm.com/media/referencedocuments/et13pge1311liddedbroilerfinal_201412161.pdf
2: American Society for Testing and Materials (ASTM). 2015. ASTM F1695-03, Standard Test Method for the Performance of Underfired Broilers. West Conshohocken (PA): ASTM International.

3: Southern California Gas Company (SCG). 2018. "SWFS019-02 Energy and Cost Calculations.xlsx." https://www.caetrm.com/media/reference-documents/SWFS019-02_Energy_and_Cost_Calculations.xlsx
4: Livchack, D. (Fisher-Nickel, Inc.). 2017. Energy Efficient Underfired Broilers. ET Project Number ET16PGE1941. Prepared for Pacific Gas and Electric Company (PG&E). March 24. https://www.caetrm.com/media/referencedocuments/et16pge1941_energy_efficient_broilers_20170329.pdf
5: SoCalGas, 2019. "WPSCGNRCC171226A – Commercial Conveyor Broilers" Revision 01
6: NMR, DNV-GL, and Tetra-Tech, Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study, Aug. 14, 2018 (Table 48, Table 52
.

Revision Number	Date	Revision
65	3/1/2022	New Measure Added

2.26 Hot Water – Faucet Aerators

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	Hot Water

Description:

Installation of a faucet aerator with a flow rate of 1.5 GPM or less on an existing faucet with high flow in a commercial setting.

Baseline Efficiency:

The baseline efficiency case is an existing faucet aerator with Federal Standard flow rate of 2.2 GPM.[1]

High Efficiency:

The high efficiency case is a low flow faucet aerator with EPA WaterSense[2] specified maximum flow rate of 1.5 GPM.

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated using the Federal Energy Management Program ("FEMP") Energy Cost Calculator. [3] kW savings are calculated using the demand impact model.[4]

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
E21C1a028 E21C1b031 E21C1d030 E21C2a028 E21C2b031 E21C2d030 E21C3a044 E21C3b045 E21C3d046	Faucet Aerator	**Electric**	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	309	0.01	n/a
E21C3a045 E21C3b046 E21C3d047 G21C1a005 G21C1b017 G21C2a005 G21C2b017	Faucet Aerator	Gas	LBES Retro LBES New LBES DI LBES Retro LBES New SBES DI SBES New	n/a	n/a	1.7

E21C3a046 E21C3b047 E21C3d048	Faucet Aerator	Oil	Muni Retro Muni New Muni DI	n/a	n/a	1.7
E21C3a047 E21C3b048 E21C3d049	Faucet Aerator	Propane	Muni Retro Muni New Muni Gas	n/a	n/a	1.7

Measure Life:

The measure life for a faucet aerator is 10 years.[5]

Other Resource Impacts:

There are deemed water savings of 5,460 gallons/unit.[3]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a028	Faucet Aerator	Electric	LBES Retro LBES New LBES DI	1.00	0.99	1.00	1.00	1.00	0.31	0.81
E21C3a045	Faucet Aerator	Gas	LBES Retro LBES New LBES DI	1.00	n/a	0.99	n/a	n/a	n/a	n/a
E21C3a046	Faucet Aerator	Oil	LBES Retro LBES New LBES DI	1.00	n/a	0.99	n/a	n/a	n/a	n/a
E21C3a047	Faucet Aerator	Propane	LBES Retro LBES New LBES DI	1.00	n/a	0.99	n/a	n/a	n/a	n/a
E21C1b031 E21C1d030 E21C2a028 E21C2b031 E21C2d030 E21C3a044 E21C3b045 E21C3d046	Faucet Aerator	Electric	SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	1.00	1.00	1.00	1.00	1.00	0.31	0.81
E21C3b046 E21C3d047 G21C1a005 G21C1b017 G21C2a005 G21C2b017	Faucet Aerator	Gas	LBES Retro LBES New SBES Retro SBES New	1.00	n/a	1.00	n/a	n/a	n/a	n/a

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3b047 E21C3d048	Faucet Aerator	Oil	Muni Retro Muni New Muni Gas	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3b048 E21C3d049	Faucet Aerator	Propane	Muni Retro Muni New Muni Gas	1.00	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [6]

Coincidence Factors:

Summer and winter coincidence factors of 31% and 81% have been utilized per the MA demand impact model.[4]

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes " Water Heater – Electric".
For non-electric measures, see Appendix 1 C&I Load Shapes "Non- Electric Measures"

Endnotes:
1: In 1998, the Department of Energy adopted a maximum flow rate standard of 2.2 gpm at 60 psi for all faucets: 63 Federal Register 13307; March 18, 1998. https://www.epa.gov/sites/production/files/2017-02/documents/ws-specification-home-final-suppstatement-v1.0.pdf
2: WaterSense: Bathroom Faucets. https://www.epa.gov/watersense/bathroom-faucets
3: Federal Energy Management Program ("FEMP") Energy Cost Calculator for Faucets and Showerheads. Available at: https://www.energy.gov/eere/femp/energy-cost-calculator-faucets-and-showerheads. On average, faucets are assumed to run 30 minutes per day, 260 days per year. Actual usage values should be used, when known, in lieu of default savings values.
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
5: Natural Gas Energy Efficiency Potential in Massachusetts. Prepared for GasNetworks, GDS Associates, April 2009. http://ma-eeac.org/wordpress/wp-content/uploads/5_Natural-Gas-EE-Potenial-in-MA.pdf
6: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf

2.27 Hot Water – Pre-Rinse Spray Valve

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Hot Water

Description:

Pre-Rinse Spray Valve: Retrofitting existing standard spray nozzles in locations where service water is supplied by hot water heater with new low flow pre-rinse spray nozzles with an average flow rate of 1.6 GPM.

Baseline Efficiency:

Pre-Rinse Spray Valve, Gas: The baseline efficiency case is an existing efficiency spray valve.

High Efficiency:

Pre-rinse Spray Valve, Gas: The high efficiency case is a low flow pre-rinse spray valve with an average flow rate of 1.6 GPM. [1]

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results. [2] [3]

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔMMBtu
E21C1a040 E21C1b046 E21C1d040 E21C2a040 E21C2b046 E21C2d040 E21C3a075 E21C3b074 E21C3d075	Pre-Rinse Spray Valve	Electric	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	126 kWh for grocery and 957 kWh for non-grocery facility type	
E21C3a076 E21C3b075 E21C3d076 G21C1a009 G21C1b020 G21C2a009 G21C2b020 G21C1c006 G21C2c006	Pre-Rinse Spray Valve	Gas	Muni Retro Muni New Muni DI LBES Retro LBES New SBES Retro SBES New LBES Mid SBES Mid		11.4

E21C3a077 E21C3b076 E21C3d077	Pre-Rinse Spray Valve,	Oil	LBES Retro SBES Retro Muni Retro		11.4
E21C3a078 E21C3b077 E21C3d078	Pre-Rinse Spray Valve	Propane	LBES Retro SBES Retro Muni Retro		11.4

Measure Life:

The measure life is 8 years.[2]

Other Resource Impacts:

There are water savings of 6,410 gallons per unit.[2]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a040 E21C1b046 E21C1d040	Pre-Rinse Spray Valve	Electric	LBES Retro LBES New LBES DI	1.00	0.99	1.00	1.00	1.00	0.52	1.00
G21C1a009 G21C1b020	Pre-Rinse Spray Valve	Gas	LBES Retro LBES New	1.00	n/a	0.99	n/a	n/a	n/a	n/a
E21C2a040 E21C2b046 E21C2d040 E21C3a075 E21C3b074 E21C3d075	Pre-Rinse Spray Valve	Electric	SBES Retro SBES New SBES DI Retro Muni New Muni DI	1.00	1.00	1.00	1.00	1.00	0.52	1.00
E21C3a076 E21C3b075 E21C3d076 G21C2a009 G21C2b020 G21C2c006	Pre-Rinse Spray Valve	Gas	Muni Retro Muni New Muni DI SBES Retro SBES New LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a077 E21C3b076 E21C3d077	Pre-Rinse Spray Valve,	Oil	Muni New Muni Retro Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a078 E21C3b077 E21C3d078	Pre-Rinse Spray Valve	Propane	Muni New Muni Retro	1.00	n/a	1.00	n/a	n/a	n/a	n/a

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
			Muni DI							

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise. The LBES program uses a realization rate of 99.9% from a 2015 impact evaluation on commercial and industrial programs. [5]

<u>Coincidence Factors:</u>

A summer coincidence factor of 52% and a winter coincidence factor of 100% is utilized.[4]

Impact Factors for Calculating Net Savings (Upstream/Midstream Only)[6]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
G21C1c006 G21C2c006	Pre Rinse Spray Valve	LBES Mid SBES Mid	0.237	0.07	0	0.83

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes " Water Heater – Electric".
For non-electric measures, see Appendix 1 C&I Load Shapes "Non- Electric Measures"

<u>Endnotes</u>:
1: Per Massachusetts program administrator internal analysis.
2: Impact Evaluation of Massachusetts Prescriptive Gas Pre-Rinse Spray Valves, DNV GL, November 2014. http://ma-eeac.org/wordpress/wp-content/uploads/Prescriptive-Gas-Pre-Rinse-Spray-Valve-Measure-Impact-Evaluation.pdf
3: Connecticut Program Savings Document 2020. Measure 3.2.1: Water-Saving Measures.
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
5: DNV GL, September 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. Prepared for NH Electric and Gas Utilities.
https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf
6: NMR Group, Inc. (2018). Massachusetts Sponsors' Commercial and Industrial Free-ridership and Spillover Study. 2018_NMR_CI FR-SO Report

2.28 Hot Water – Showerheads

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Hot Water

Description:

Thermostatic Shut-Off Valve: Installation of a stand-alone thermostatic shut-off valve on standard flow showerhead.
Low-Flow Showerhead, Electric, Gas, Oil, Propane: Installation of a low-flow showerhead with a flow rate of 1.5 GPM or less.

Baseline Efficiency:

Thermostatic Shut-Off Valve: The baseline efficiency is an existing standard-flow showerhead (2.5 GPM) with no thermostatic shut-off valve.
Low-Flow Showerhead, Electric, Gas, Oil, Propane: The baseline efficiency is an existing standard-flow showerhead (2.5 GPM).

High Efficiency:

Thermostatic Shut-Off Valve: The high efficiency case is a standard flow showerhead (2.5 GPM) with the addition of a stand-alone thermostatic shut-off valve.
Low-Flow Showerhead, Electric, Gas, Oil, Propane: The high efficiency case is a low-flow showerhead (1.5 GPM).

Algorithms for Calculating Primary Energy Impact:

Low-Flow Showerhead with Thermostatic Valve: Unit savings are deemed.[1] kW savings are calculated using the demand impact model.[2]

Low-Flow Showerhead, Electric and Low-Flow Showerhead, Gas: Unit savings are deemed. [3]

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
G21C1a006 G21C1b018 G21C2a006 G21C2b018	Thermostatic Shut-Off Valve	Gas	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	n/a	n/a	0.33

E21C1a033 E21C1b044 E21C1d033 E21C2a033 E21C2b044 E21C2d033 E21C3a056 E21C3b066 E21C3d056	Thermostatic Shut-Off Valve	Electric	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	69	0.01	
E21C3a058 E21C3b068 E21C3d058	Thermostatic Shut-Off Valve	Oil	Muni Retro Muni New Muni DI	n/a	n/a	0.33
E21C3a059 E21C3b069 E21C3d059	Thermostatic Shut-Off Valve	Propane	Muni Retro Muni New Muni DI	n/a	n/a	0.33
E21C1a034 E21C1b045 E21C1d034 E21C2a034 E21C2b045 E21C2d034 E21C3a060 E21C3b070 E21C3d060	Low-Flow Showerhead	Electric	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	507	0.09	
G21C1a007 G21C1b019 G21C2a007 G21C2b019	Low-Flow Showerhead	Gas	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni	n/a	n/a	2.65
E21C3a062 E21C3b072 E21C3d062	Low-Flow Showerhead	Oil	Muni Retro Muni New Muni DI	n/a	n/a	2.65
E21C3a063 E21C3b073 E21C3d063	Low-Flow Showerhead	Propane	Muni Retro Muni New Muni DI	n/a	n/a	2.65

Measure Life:

The measure life for all Showerheads is 10 years.[4]

Other Resource Impacts:

Thermostatic Shut-Off Valve: Annual water savings of 558 gallons per unit.[1]

Low-Flow Showerhead, Electric, Gas, Oil, Propane: Annual water savings of 7,300 gallons per unit.[3]

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1a006 G21C1b018 G21C2a006 G21C2b018	Thermostatic Shut-Off Valve, Gas	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C1a033 E21C1b044 E21C1d033 E21C2a033 E21C2b044 E21C2d033 E21C3a056 E21C3b066 E21C3d056	Thermostatic Shut-Off Valve, Electric	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	1.00	1.00	n/a	1.00	1.00	0.31	0.81
E21C3a058 E21C3b068 E21C3d058	Thermostatic Shut-Off Valve, Oil	Muni Retro Muni New Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a059 E21C3b069 E21C3d059	Thermostatic Shut-Off Valve, Propane	Muni Retro Muni New Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C1a034 E21C1b045 E21C1d034 E21C2a034 E21C2b045 E21C2d034 E21C3a060 E21C3b070 E21C3d060	Low-Flow Showerhead, Electric	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni DI	1.00	1.00	n/a	1.00	1.00	0.31	0.81

G21C1a007 G21C1b019 G21C2a007 G21C2b019	Low-Flow Showerhead, Gas	LBES Retro LBES New LBES DI SBES Retro SBES New SBES DI Muni Retro Muni New Muni	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a062 E21C3b072 E21C3d062	Low-Flow Showerhead, Oil	Muni Retro Muni New Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a
E21C3a063 E21C3b073 E21C3d063	Low-Flow Showerhead, Propane	Muni Retro Muni New Muni DI	1.00	n/a	1.00	n/a	n/a	n/a	n/a

In-Service Rates:

All programs have a 100% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Summer and winter coincidence factors of 31% and 81% have been utilized per the MA demand impact model.[2]

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes " Water Heater – Electric".
For non-electric measures, see Appendix 1 C&I Load Shapes "Non- Electric Measures"

Endnotes:
1: National Grid, 2014. Review of ShowerStart evolve. Calculation document provided in the MA TRM.
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
3: Federal Energy Management Program ("FEMP") Energy Cost Calculator for Faucets and Showerheads.. On average, showerheads are assumed to run 20 minutes per day, 365 days per year. Actual usage values should be used, when known, in lieu of default savings values. ΔMMBtu based on **Navigant Consulting (2018). Demand Impact Model Update.**
4: Natural Gas Energy Efficiency Potential in Massachusetts. Prepared for GasNetworks, GDS Associates, April 2009. http://ma-eeac.org/wordpress/wp-content/uploads/5_Natural-Gas-EE-Potenial-in-MA.pdf

2.29 Hot Water - Steam Traps

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

Repair or replace malfunctioning steam traps.

Baseline Efficiency:

The baseline efficiency case is a failed steam trap.

High Efficiency:

The high efficiency case is a repaired or replaced steam trap.

Algorithms for Calculating Primary Energy Impact:

Deemed annual unit savings are as detailed in the table below[1]:

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔMMBtu
G21C1a014 G21C2a014 E21C3a084 E21C3d084	Steam Trap	Gas	LBES Retro – Gas SBES Retro – Gas Muni Retro Muni DI	n/a	Low pressure (≤= 10 psig): 8.4 High pressure (>10 psig): 35.6
E21C3a085 E21C3d085	Steam Trap	Oil	Muni Retro Muni DI	n/a	Low pressure (≤= 10 psig): 8.4 High pressure (>10 psig): 35.6
E21C3a086 E21C3d086	Steam Trap	Propane	Muni Retro Muni DI	n/a	Low pressure (≤= 10 psig): 8.4 High pressure (>10 psig): 35.6

Measure Life:

The measure life is 6 years. [2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1a014 G21C2a014 E21C3a084 E21C3d084	Steam Trap	Gas	LBES Retro – Gas SBES Retro – Gas Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a085 E21C3d085	Steam Trap	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a086 E21C3d086	Steam Trap	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% electric realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1 – "Boiler Distribution".

Endnotes:

1: Energy and Resource Solutions, April 2018. Two-Tier Steam Trap Savings Study. Prepared for National Grid and Eversource of Massachusetts. http://ma-eeac.org/wordpress/wp-content/uploads/MA-CIEC-Two-Tier-Steam-Traps-Memo-FINAL.pdf

2: DNV GL, June 2015. Massachusetts 2013 Prescriptive Gas Impact Evaluation – Steam Trap Evaluation Phase I. Prepared for Massachusetts Gas Program Administrators and Massachusetts Energy Efficiency Advisory Council. http://ma-eeac.org/wordpress/wp-content/uploads/MA-2013-Prescriptive-Gas-Impact-Evaluation-Steam-Trap-Evaluation-Phase-1.pdf

2.30 HVAC – Boiler Reset Controls

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

Boiler Reset Controls: Boiler Reset Controls are devices that automatically control boiler water temperature based on outdoor or return water temperature using a software program.

Baseline Efficiency:

The baseline efficiency case is a boiler without reset controls.

High Efficiency:

The high efficiency case is a boiler withreset controls.

Algorithms for Calculating Primary Energy Impact:

.
Unit savings are deemed based on study results.[1]

BC Measure ID	Measure Name	Fuel Type	Program	ΔMMBtu/unit
E21C3a019 E21C3d021 G21C1a010 G21C2a010	Boiler Reset Controls	Gas	Muni Retro Muni DI LBES Retro SBES Retro	35.5
E21C3a020 E21C3d022	Boiler Reset Control	Oil	Muni Retro Muni DI	35.5
E21C3a021 E21C3d023	Boiler Reset Control	Propane	Muni Retro Muni DI	35.5

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3a019 E21C3d021 G21C1a010 G21C2a010	Boiler Reset Controls	Gas	Muni Retro Muni DI LBES Retro SBES Retro	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a020 E21C3d022	Boiler Reset Control	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a021 E21C3d023	Boiler Reset Control	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes "Boiler Distribution".
For non-electric measures, see Appendix 1 C&I Load Shapes "Non- Electric Measures"

Endnotes:

1: GDS Associates, Inc. (2009). Natural Gas Energy Efficiency Potential in Massachusetts, as cited in the Massachusetts TRM. Study assumes 710.46 MMBTU base use with 5% savings factor. GDS_2009_Natural_Gas_Energy_Efficiency_Potential_in_MA.
2: ACEEE, 2006. Emerging Technologies Report: Advanced Boiler Controls.

2.31 HVAC – Circulator Pump

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

Single-phase circulator pumps used in C&I buildings used for hydronic heating and system hot water.

Baseline Efficiency:

The baseline system is a pump without an EC motor. The baseline system may have no control, a timer, aquastat, or be on demand. The baseline system is assumed to run a weighted average of these four control types.

High Efficiency:

The high efficiency case is a circulator pump with an ECM.

Algorithms for Calculating Primary Energy Impact:

Savings depend on application and pump size as described in table below.[1]

Size (Horsepower)	Type	kW	kWh
<= 1 HP	Hydronic Heating	$\Delta kW = 0.245 * HP_{rated} + 0.02$	$\Delta kWh = 1,325 * HP_{rated} + 111$
<= 1 HP	Service Hot Water	$\Delta kW = 0.245 * HP_{rated} + 0.02$	$\Delta kWh = 2,780 * HP_{rated} + 233$
> 1 HP	Hydronic Heating	$\Delta kW = 0.265$	$\Delta kWh = 1,436$
> 1 HP	Service Hot Water	$\Delta kW = 0.265$	$\Delta kWh = 3,013$

Measure Life:

The measure life is 20 years.[2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[3]

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b018	Circulator Pump	LBES New	1.000	0.999	n/a	1.000	1.000	0.820	0.050
E21C2b018	Circulator Pump	SBES New	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C3b030	Circulator Pump	Muni New	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C1c001	Midstream Circulator Pump	LBES Midstream	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C2c001	Midstream Circulator Pump	SBES Midstream	1.000	1.000	n/a	1.000	1.000	0.820	0.050

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A summer coincidence factor of 82.0% and a winter coincidence factor of 5.0% are utilized.[3]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Heating & Cooling"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[4]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c001 E21C2c001	Midstream Circulator Pump	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860

Endnotes:
1: The Cadmus Group, 2017. Circulator Pump Technical Memo. Prepared for National Grid and Eversource engineers.

2: Energy & Resource Solutions, November 2005. Measure Life Study. Prepared for The Massachusetts Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
3: Navigant Consulting (2018). RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf
4: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

2.32 HVAC- Demand Control Ventilation

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

The measure controls the quantity of outside air to an air handling system based on detected space CO_2 levels. The installed systems monitor the CO_2 in the spaces or return air and reduce the outside air use when possible to save energy while meeting indoor air quality standards.

Baseline Efficiency:

The baseline for midstream measures is the demand control ventilation required based on climate one, OA% and total CFM supply air.

The baseline efficiency case for all other measures is site specific and reflective of any existing ventilation control strategies currently employed.

High Efficiency:

The high efficiency case is the installation of an outside air intake control based on CO_2 sensors.

Algorithms for Calculating Primary Energy Impact:

The energy and demand savings are calculated using the following algorithms and inputs:

$$\Delta kWh = kBtuh \times \frac{1\ ton}{12\ kBtuh} \times Save_{kWh}$$

$$\Delta kW = kBtuh \times \frac{1\ ton}{12\ kBtuh} \times Save_{kW}$$

Where:

$kBtuh$ = Capacity of the cooling equipment in kBtu per hour

$Save_{kWh}$ = Average annual kWh reduction per ton of cooling capacity: 170 kWh/ton [1]

$Save_{kW}$ = Average kW reduction per ton of cooling capacity: 0.15 kW/ton [2]

Measure Life:

The measure life is 10 years.[3]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a018 E21C1d020	Demand Control Ventilation	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.820	0.050
E21C2a018 E21C2d020	Demand Control Ventilation	SBES Retro SBES DI	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C3a024 E21C3d026	Demand Control Ventilation	Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C1c002 E21C2c002	Midstream Demand Control Ventilation	LBES Midstream SBES Midstream	1.000	1.000	n/a	1.000	1.000	0.820	0.050

<u>In-Service Rates:</u>

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates[4]:</u>

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

CFs are based on Massachusetts TRM standard assumptions.

Energy Load Shape:

Appendix 1 C&I Load Shapes– "C&I Heating and Cooling"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[5]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c002 E21C2c002	Midstream Demand Control Ventilation	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860

<u>Endnotes</u>:

1: Keena, Kevin, 2008. Analysis of CO2 Control Energy Savings on Unitary HVAC Units. Prepared for National Grid.
2: Keena, Kevin, 2008. Analysis of CO2 Control Energy Savings on Unitary HVAC Units. Prepared for National Grid.
3: Energy & Resource Solutions, November 2005. Measure Life Study. Prepared for The Massachusetts Joint Utilities; Table 1-1. Measure life is assumed to be the same as Enthalpy Economizer. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
4: New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Impact Evaluation report. Table 3
5: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

Revision History:

Revision Number	Date	Description
45	1/14/2022	Updated midstream and retrofit baselines.
46	1/14/2022	Fixed broken link.

2.33 HVAC- Dual Enthalpy Economizer Controls

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

The measure is to upgrade the outside-air dry-bulb economizer to a dual enthalpy economizer. The system will continuously monitor the enthalpy of both the outside air and return air. The system will control the system dampers adjust the outside quantity based on the two readings.

Baseline Efficiency:

The baseline efficiency case for this measure assumes the relevant HVAC equipment is operating with a fixed dry-bulb economizer.

High Efficiency:

The high efficiency case is the installation of an outside air economizer utilizing two enthalpy sensors, one for outdoor air and one for return air.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = kBtuh \times \frac{1\ ton}{12\ kBtuh} \times SAVE_{kWh}$$

$$\Delta kW = kBtuh \times \frac{1\ ton}{12\ kBtuh} \times SAVE_{kW}$$

Where:

kBtu/h = Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h)

$SAVE_{kWh}$ = Average annual kWh reduction per ton of cooling capacity: 289 kWh/ton [1]

$SAVE_{kW}$ = Average kW reduction per ton of cooling capacity: 0.289 kW/ton [2]

Measure Life:

The measure life is 10 years. [3]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a020 E21C1d022	Dual Enthalpy Economizer Controls	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.342	0.000
E21C2a020 E21C2d022	Dual Enthalpy Economizer Controls	SBES Retro SBES DI	1.000	1.000	n/a	1.000	1.000	0.342	0.000
E21C3a026 E21C3d028	Dual Enthalpy Economizer Controls	MES Retro MES DI	1.000	1.000	n/a	1.000	1.000	0.342	0.000
E21C1c004 E21C2c004	Midstream Dual Enthalpy Economizer Controls	LBES Midstream SBES Midstream	1.000	1.000	n/a	1.000	1.000	0.342	0.000

<u>In-Service Rates:</u>

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

Coincidence factors are based on 2011 NEEP C&I Unitary AC Loadshape Project [4]

Energy Load Shape:

See Appendix 1C&I Load Shapes – "C&I Heating and Cooling".

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[5]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c004 E21C2c004	Midstream Dual Enthalpy Economizer Controls	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860

<u>Endnotes</u>:
1, 2: Patel, Dinesh, 2001. Energy Analysis: Dual Enthalpy Control. Prepared for Eversource (NSTAR).
3: Energy & Resource Solutions, November (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities.https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf

4: Coincidence Factors are from 2011 NEEP HVAC Loadshape Study Table 0-5 (ISO_NE on Peak for NE-North)
https://neep.org/sites/default/files/resources/NEEP_HVAC_Load_Shape_Report_Final_August2_0.pdf
5: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators.
http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

2.34 HVAC – Duct Insulation

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

For existing ductwork in non-conditioned spaces, insulate ductwork. This could include replacing un-insulated flexible duct with rigid insulated ductwork and installing 1" to 2" of duct-wrap insulation.

Baseline Efficiency:

The baseline efficiency case is existing, uninsulated ductwork in unconditioned spaces (e.g. attic or basement).

High Efficiency:

The high efficiency condition is insulated ductwork in unconditioned spaces.

Algorithms for Calculating Primary Energy Impact:

Deemed average annual MMBtu savings of 0.13[1] is assumed per unit, where unit is defined as number of square feet of ductwork treated.

Measure Life:

The measure life is 20 years.[1]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3a027 E21C3d029	Duct Insulation	Electric	Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.350	0.000
E21C3a028 E21C3d030	Duct Insulation	Gas	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a029 E21C3d031	Duct Insulation	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C3a030 E21C3d032	Duct Insulation	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

For electric measures, a summer coincidence factor of 35.0% is utilized.[2]

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes "Weighted HVAC – Multi-Family"
For non-electric measures, see Appendix 1 C&I Load Shapes "Non-Electric Measures".

Endnotes:
1: National Grid Staff Estimate, 2010. MA SBS-DI Duct Sealing and Insulation Scenario and Deemed Savings. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4885c6996f2b5047df743/view?authToken=fa8e547661bf80dea8750ffa5a1d3608215165882ceaf6ebc0b7193a1ab071622426a78ec0a491b80535c621447604a03ab75d3119793c326860fd96007eec8b851ba43c196fab
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. Weighted CF by end use (Table 3). http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

2.35 HVAC – Duct Sealing

Measure Code	TBD
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

For existing ductwork in non-conditioned spaces, seal ductwork. This could include sealing leaky fixed ductwork with mastic or aerosol.

Baseline Efficiency:

The baseline efficiency case is existing, non-sealed (leaky) in unconditioned spaces (e.g. attic or basement).

High Efficiency:

The high efficiency condition is air sealed ductwork in unconditioned spaces.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results:
Δ MMBtu = MMBtu/unit x Units
Where:
Unit = Number of square feet of ductwork treated
MMBtu/unit = Average annual MMBtu savings per unit: 0.13[1]

Measure Life:

The measure life is 20 years.[2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a021 E21C1d023	Duct Sealing	Electric	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.350	0.000

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C2a021 E21C2d023	Duct Sealing	Electric	SBES Retro SBES DI	1.000	1.000	n/a	1.000	1.000	0.350	0.000
E21C3a031 E21C3d033	Duct Sealing	Electric	Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.350	0.000
E21C3a032 E21C3d034	Duct Sealing	Gas	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a033 E21C3d035	Duct Sealing	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a034 E21C3d036	Duct Sealing	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A summer coincidence factor if 35.0% is utilized.[2]

Energy Load Shape:

For electric measures, see Appendix 1 C&I Load Shapes “Weighted HVAC- Multi-Family”
For non-electric measures, see Appendix 1 C&I Load Shapes “Non-Electric Measures”
.

Endnotes:
1: National Grid Staff Estimate, 2010. MA SBS-DI Duct Sealing and Insulation Scenario and Deemed Savings. Based on sealing the duct system from 25% to 5% leakage. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4885c6996f2b5047df743/view?authToken=19819e606c75814d

e7e2d8af2fec676653fdc0f39f9bd79f566ee687c4851bcdb91e2216408550e53766db986dc9c0640b2776bb702f79b7f56a42e07d73a2cebf5c6abfb39bd1
2: Navigant Consulting, 2018. RES1 Demand Impact Model Update. Weighted CF by end use (Table 3). http://ma-eeac.org /wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

2.36 HVAC – Energy Management System

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

The measure is the installation of a new building energy management system (EMS) or the expansion of an existing energy management system for control of non-lighting electric and gas end-uses in an existing building on existing equipment.

Baseline Efficiency:

The baseline for this measure is site specific, calculated per vendor tools but with the consideration of the existing conditions.

High Efficiency:

The high efficiency case is the installation of a new EMS or the expansion of an existing EMS to control additional non-lighting electric or gas equipment. The EMS must be installed in an existing building on existing equipment.

Algorithms for Calculating Primary Energy Impact:

Gross energy and demand savings for energy management systems (EMS) are custom calculated using vendor tools. These tools are used to calculate energy and demand savings based on project-specific details including hours of operation, HVAC system equipment and efficiency and points controlled.

BC Measure ID	Measure Name	Fuel Type	Program	MMBtu/kWh
G21C1a012 G21C2a012	Energy Management System	Gas	LBES Retro – Gas SBES Retro – Gas	Calculated
E21C1a025 E21C1d027 E21C2a025 E21C2d027 E21C3a038 E21C3d040	Energy Management System	Electric	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	Calculated

Measure Life:

The measure life is 10 years.[1]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a025 E21C1d027	Energy Management System	LBES Retro LBES DI	1.000	0.999	1.000	1.000	1.000	0.950	1.000
E21C2a025 E21C2d027	Energy Management System	SBES Retro SBES DI	1.000	1.000	1.000	1.000	1.000	0.950	1.000
E21C3a038 E21C3d040	Energy Management System	Muni Retro Muni DI	1.000	1.000	1.000	1.000	1.000	0.950	1.000
G21C1a012 G21C2a012	Energy Management System	LBES Retro – Gas SBES Retro – Gas	1.000	n/a	1.000	1.000	1.000	0.000	0.000

<u>In-Service Rates:</u>

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

A summer coincidence factor of 95.0% and a winter coincidence factor of 100.0% is utilized.[2]

Energy Load Shape:

See Appendix 1 C&I Load Shapes “C&I Heating and Cooling”

<u>Endnotes</u>:
1: The Fleming Group, 1994. Persistence of Commercial/Industrial Non-Lighting Measures, Volume 3, Energy Management Control Systems. Prepared for New England Power Service Company.
2: New Hampshire common assumptions.

Revision History:

Revision Number	Date	Description
47	1/14/2022	Corrected baseline from “assumes the relevant HVAC equipment has no centralized control” to “site specific”

2.37 HVAC – Heat and Hot Water Combo Systems

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

Combo Condensing Furnace / Water Heater: Installation of a combination furnace.
Combo Condensing Boiler / Water Heater: This measure promotes the installation of a combined high-efficiency boiler and water heating unit. Combined boiler and water heating systems are more efficient than separate systems because they eliminate the standby heat losses of an additional tank.

Baseline Efficiency:

Combo Condensing Furnace / Water Heater: It is assumed that the baseline is an 85% AFUE furnace [1] and a separate high draw gas fired storage water heater with an efficiency rating of 0.63 UEF.
Combo Condensing Boiler / Water Heater: The baseline efficiency case is a standard efficiency gas-fired storage tank hot water heater with a separate 85% AFUE boiler for space heating purposes.

High Efficiency:

Combo Condensing Furnace / Water Heater: A new combination 97% AFUE furnace and 0.90 tankless water heater.
Combo Condensing Boiler / Water Heater: The high efficiency case is either a condensing, integrated water heater/boiler with an AFUE of >=90% or AFUE>=95%.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[2]

BC Measure ID	Measure Name	ΔMMBtu
G21C1b012 G21C2b012	Combo Condensing Furnace/Water Heater, Gas	15.1
G21C1b011 G21C2b011	Combo Condensing Boiler/Water Heater, Gas	30.5

Measure Life:

Combo Condensing Furnace / Water Heater: The measure life is 18 years.[3]

Combo Condensing Boiler/Water Heater: 20 years.[4]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b012 G21C2b012	Combo Condensing Furnace/Water Heater, Gas	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b011 G21C2b011	Combo Condensing Boiler/Water Heater, Gas	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1, C&I Load Shapes Table- "Heating and Cooling.

Endnotes:

1: Massachusetts TRM 2019 Plan-Year Report Version, 2020. Measure 3.30: HVAC Combo Furnace/Water Heater, Commercial Page 477.
2: The Cadmus Group, March 2015. High Efficiency Heating Equipment Impact Evaluation. Prepared for The Electric and Gas Program Administrators of Massachusetts, Part of the Residential Evaluation Program Area https://neep.org/sites/default/files/resources/High-Efficiency-Heating-Equipment-Impact-Evaluation-Final-Report.pdf
3: Environmental Protection Agency, 2009. Lifecycle Cost Estimate for Energy Star Furnace.
4: Natural Gas Energy Efficiency Potential in Massachusetts. Prepared for GasNetworks, GDS Associates, April 2009. http://ma-eeac.org/wordpress/wp-content/uploads/5_Natural-Gas-EE-Potenial-in-MA.pdf

Revision History:

Revision Number	Date	Description
48	1/14/2022	Update baseline. Baseline boiler should be 85% consistent with treatment elsewhere in the TRM. 30.5 MMBtu/unit savings are OK, consistent with MA assumptions:

2.38 HVAC – Heating Systems - Boilers

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

The installation of a high efficiency natural gas fired condensing hot water boiler. High-efficiency condensing boilers can take advantage of improved design, sealed combustion, and condensing flue gases in a second heat exchanger to achieve improved efficiency.

Baseline Efficiency:

Baseline efficiency is an 85% AFUE boiler.

High Efficiency:

High efficiency is per table of efficiency thresholds below.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results. [1]

BC Measure ID	Measure Name	Program	ΔMMBtu
G21C1b010 G21C2b010	<= 300 MBH (0.95 TE)	LBES New SBES New	17.7
G21C1b009 G21C2b009	<= 300 MBH (0.90 TE)	LBES New SBES New	14.7
G21C1b008 G21C2b008	301-499 MBH (0.90 TE)	LBES New SBES New	28.0
G21C1b007 G21C2b007	500-999 MBH (0.90 TE)	LBES New SBES New	51.4
G21C1b006 G21C2b006	1000-1700 MBH (0.90 TE)	LBES New SBES New	94.5
G21C1b005 G21C2b005	1701+ MBH (0.90 TE)	LBES New SBES New	165.3

Measure Life:

The measure life is 25 years. [2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b010 G21C2b010	<= 300 MBH (0.95 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b009 G21C2b009	<= 300 MBH (0.90 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b008 G21C2b008	301-499 MBH (0.90 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b007 G21C2b007	500-999 MBH (0.90 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b006 G21C2b006	1000-1700 MBH (0.90 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1b005 G21C2b005	1701+ MBH (0.90 TE)	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1 “C&I Heating & Cooling”.

Endnotes:
1: DNV GL, NMR, March 2017. Gas Boiler Market Characterization Study Phase II. Prepared for Massachusetts Program Administrators and Energy Efficiency Advisory Council. http://ma-eeac.org/wordpress/wp-content/uploads/Gas-Boiler-Market-Characterization-Study-Phase-II-Final-Report.pdf
2: ASHRAE Applications Handbook, 2003; Page 36.3.

2.39 HVAC – Heating Systems – Condensing Unit Heaters

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

Installation of a condensing gas-fired unit heater for space heating with capacity up to 300 MBH and minimum combustion efficiency of 90%.

Baseline Efficiency:

The baseline efficiency case is a standard efficiency gas fired unit heater with minimum combustion efficiency of 80%, interrupted or intermittent ignition device (IID), and either power venting or an automatic flue damper. [1] As a note, the baseline efficiency referenced applies to 2016. Baseline requirements for 2017 and on have not been finalized.

High Efficiency:

The high efficiency case is a condensing gas unit heater with 90% AFUE or greater.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.[2]

BC Measure ID	Measure Name	Program	ΔMMBtu
G21C1b013 G21C2b013	Condensing Unit Heater (<= 300 MBH) – Gas	LBES New SBES New	40.9
E21C3b033	Condensing Unit Heater (<= 300 MBH) – Oil	MES New	40.9
E21C3b034	Condensing Unit Heater (<= 300 MBH) – Propane	MES New	40.9

Measure Life:

The measure life is 18 years. [3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b013 G21C2b013	Condensing Unit Heater – Gas	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3b033	Condensing Unit Heater – Oil	MES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3b034	Condensing Unit Heater – Propane	MES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1 “C&I Heating & Cooling”.

Endnotes:
1: 2015 International Energy Conservation Code
2: NYSERDA Deemed Savings Database (Rev 11); Measure Name: A.UNIT-HEATER-COND.<300000.CI.).).N. The database provides savings of 204.6 MMBtu per million BTU/hr of heater input capacity. Assume average unit size of 200,000 BTU capacity.
3: Ecotrope, Inc., August 2003. Natural Gas Efficiency and Conservation Measure Resource Assessment for the Residential and Commercial Sectors. Prepared for the Energy Trust of Oregon. https://library.cee1.org/system/files/library/1366/544.pdf

Revision Number	Date	Description
49	1/14/2022	Corrected baseline to reference most current code.

2.40 HVAC – Heating Systems – Furnaces

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

The installation of a high efficiency natural gas warm air furnace with an electronically commutated motor (ECM) for the fan. High efficiency furnaces are better at converting fuel into direct heat and better insulated to reduce heat loss. ECM fan motors significantly reduce fan motor electric consumption as compared to both shaped-pole and permanent split capacitor motors.

Baseline Efficiency:

The baseline efficiency in an 85% AFUE furnace.

High Efficiency:

The high efficiency scenario assumes either a gas-fired furnace equal or higher than 95% AFUE or 97% AFUE.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results. [1]

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW	ΔMMBtu
G21C1b014 G21C2b014	Furnace, 95%	LBES New SBES New	168	0.124	5.7
G21C1b015 G21C2b015	Furnace, 97%	LBES New SBES New	168	0.124	6.7

Measure Life:

The measure life is 18 years. [2]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[3]

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b014 G21C2b014	Furnace, 95%	LBES New SBES New	1.000	1.000	1.000	n/a	n/a	0.000	0.160
G21C1b015 G21C2b015	Furnace, 97%	LBES New SBES New	1.000	1.000	1.000	n/a	n/a	0.000	0.160

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A winter coincidence factor of 16% is utilized. Values pertain to other resource impacts for the EC motors.

Energy Load Shape:

See Appendix 1 “C&I Heating & Cooling”.

Endnotes:

1: DNV-GL, 2015. Recalculation of Prescriptive Program Gas Furnace Savings Using New Baseline. Prepared for National Grid, Massachusetts.
2: ASHRAE Applications Handbook, 2003; Page 36.
3: Massachusetts TRM 2019 Plan-Year Report Version, 2020. Measure 3.42: HVAC Combo Furnace, Gas, Commercial Page 510

2.41 HVAC – Heating Systems – Infrared Heater

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

The installation of a gas-fired low intensity infrared heating system in place of unit heater, furnace, or other standard efficiency equipment. Infrared heating uses radiant heat as opposed to warm air to heat buildings. In commercial environments with high air exchange rates, heat loss is minimal because the space's heat comes from surfaces rather than air.

Baseline Efficiency:

The baseline efficiency case is a standard efficiency gas-fired unit heater with combustion efficiency of 80%.[1]

High Efficiency:

The high efficiency case is a gas-fired low-intensity infrared heating unit.

Algorithms for Calculating Primary Energy Impact:

Unit savings are calculated as:

$$\Delta MMBtu = \frac{kBtu}{hr_{input}} \times \frac{EFLH_{heating}}{1000} \times \left(1 - \frac{HDD_{55}\,(55 - T_{design})}{HDD_{65}\,(55 - T_{design})}\right)$$

Where,

$\frac{kBtu}{hr_{input}}$ = Fuel input rating of the installed equipment
$EFLH_{heating}$ = Heating equivalent full-load hours from Appendix 2.
HDD_{55} = Heating degree days with 55-degree bases
HDD_{65} = Heating degree days with 65-degree base
T_{design} = Equipment design temperature

Alternatively, unit savings are deemed based on study results.[2]

BC Measure ID	Measure Name	Fuel Type	Program	ΔMMBtu
G21C1b016 G21C2b016	Infrared Heater	Gas	LBES New SBES New	12.0
E21C3b064	Infrared Heater	Propane	MES New	12.0

Measure Life:

The measure life is 17 years. [3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1b016 G21C2b016	Infrared Heater	LBES New SBES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3b064	Infrared Heater	MES New	1.000	n/a	1.000	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100.0% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

Not applicable for this measure since no electric savings are claimed.

Energy Load Shape:

See Appendix 1 “C&I Heating & Cooling”.

<u>Endnotes</u>:
1: 2015 International Energy Conservation Code
2: KEMA, June 2013. Impact Evaluation of 2011 Prescriptive Gas Measures; Page 1-5. http://ma-eeac.org/wordpress/wp-content/uploads/Impact-Evaluation-of-2011-Prescription-Gas-Measures-6.27.13.pdf
3: Nexant, 2006. DSM Market Characterization Report. Prepared for Questar Gas.

Revision Number	Date	Description
50	1/14/2022	Corrected baseline to reference most current code.
71	3/1/2022	Updated with reference to appendix 2 for new EFLH values based on NH TMY3 Data.

2.42 HVAC – High Efficiency Chiller

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

This measure promotes the installation of efficient water-cooled and air-cooled water chilling packages for comfort cooling applications. Eligible chillers include air-cooled, water cooled rotary screw and scroll, and water-cooled centrifugal chillers for single chiller systems or for the lead chiller only in multi-chiller systems.

Baseline Efficiency:

The baseline efficiency case assumes compliance with the efficiency requirements as mandated by New Hampshire State Building Code. Energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2015.

The table below details the specific efficiency requirements by equipment type and capacity.

Chiller - Minimum Efficiency Requirements [1]:

	Size Category (Tons)	Units	Path A	Path A	Path B	Path B
			Full Load	**IPLV**	**Full Load**	**IPLV**
	Air-cooled chillers					
	< 150	EER	10.100	13.700	9.700	15.800
	≥ 150	EER	10.100	14.000	9.700	16.100
	Water cooled, electrically operated, positive displacement (rotary screw and scroll)					
	< 75	kW/ton	0.750	0.600	0.780	0.500
	≥ 75 and < 150	kW/ton	0.720	0.560	0.750	0.490
	≥ 150 and < 300	kW/ton	0.660	0.540	0.680	0.440
	≥ 300 and <600	kW/ton	0.610	0.520	0.625	0.410
	≥ 600	kW/ton	0.560	0.500	0.585	0.380
	Water cooled, electrically operated, centrifugal					
	< 150	kW/ton	0.610	0.550	0.695	0.440
	≥ 150 and < 300	kW/ton	0.610	0.550	0.635	0.400

	≥ 300 and < 400	kW/ton	0.560	0.520	0.595	0.390
	≥ 400 and <600	kW/ton	0.560	0.500	0.585	0.380
	≥ 600	kW/ton	0.560	0.500	0.585	0.380

For water cooled ≤300 tons positive displacement is the baseline. For > 300 tons Centrifugal is the baseline. 2 Path A is intended for applications where significant operating time is expected at full load. Path B is intended for applications where significant operating time is expected at part-load.

High Efficiency:

The high efficiency scenario assumes water chilling packages that exceed the efficiency levels required by New Hampshire State Building Code and meet the minimum efficiency requirements as stated in the New Construction HVAC energy efficiency rebate forms.

Algorithms for Calculating Primary Energy Impact:

Gross energy and demand savings for chiller installations may be custom calculated using the PA's Chillers savings calculation tool. These tools are used to calculated energy and demand savings based on site-specific chiller plant details including specific chiller plan equipment, operational staging, operating load profile and load profile.

Alternatively, the energy and demand savings may be calculated using the algorithms and inputs below. Please note that consistent efficiency types (FL or IPLV) must be used between the baseline and high efficiency cases. It is recommended that IPLV be used over FL efficiency types when possible.

Air-Cooled Chillers:
$kWh = Tons * (12/ EER_{BASE} - 12/ EER_{EE}) * Hours$
$kW = Tons * (12/ EER_{BASE} - 12/ EER_{EE})$

Water-Cooled Chillers:
$kWh = Tons * (kW/ ton_{BASE} - kW/ ton_{EE}) * Hours$
$kW = Tons * (kW/ ton_{BASE} - kW/ ton_{EE}) * (LF/100)$

Where:
Tons = Rated capacity of the cooling equipment
EER_{BASE} = Energy Efficiency Ratio of the baseline equipment. See table below for values.
EER_{EE} = Energy Efficiency Ratio of the efficient equipment. Site-specific.
kW/ton_{BASE} = Energy efficiency rating of the baseline equipment. See table below for values.
kW/ton_{EE} = Energy efficiency rating of the efficient equipment. Site-specific.
Hours = Equivalent full load hours for chiller operation from Appendix 2.

Measure Life:

The measure life is 23 years.[2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b053	Chillers – IPLV used	LBES New	1.000	0.999	n/a	1.000	1.000	0.490	0.060
E21C2b053	Chillers – IPLV used	SBES New	1.000	1.000	n/a	1.000	1.000	0.490	0.060
E21C3b084	Chillers – IPLV used	Muni New	1.000	1.000	n/a	1.000	1.000	0.490	0.060
E21C1b052	Chillers – FL used	LBES New	1.000	0.999	n/a	1.000	1.000	0.860	0.100
E21C2b052	Chillers – FL used	SBES New	1.000	1.000	n/a	1.000	1.000	0.860	0.100
E21C3b083	Chillers – FL used	Muni New	1.000	1.000	n/a	1.000	1.000	0.860	0.100

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are based on prospective statewide results from 2015 prescriptive chiller study. [3]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Electric Chiller (Combined)".

Endnotes:
1: Energy Solutions, 2018. Northeast Chillers Market Research.
2: GDS Associates, June 2007. Measure Life Report, Residential and Commercial/Industrial Lighting and HVAC Measures, https://library.cee1.org/system/files/library/8842/CEE_Eval_MeasureLifeStudyLights%2526HVACGDS_1Jun2007.pdf
3: DNV GL, October 2015. Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. Prepared for the MA PAs and EEAC. http://ma-eeac.org/wordpress/wp-content/uploads/MA30-Prescriptive-Chiller-and-CAIR-Report_FINAL_151026.pdf
4: KEMA inc, 2015. Impact Evaluation of Prescriptive Chiller and Compressed Air Installations. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee488686996f24a5b7df77b/view?authToken=b6501145f0e30abd7

ca606f9b9e786b4ca1d1c1b64f4305fcc879bb360065f0978f0d3b139677be691407f1ee45095d58a488538bc5577782deb127cafd8e7eb197da16b1912a7

Revision Number	Issue Date	Description
51	1/14/2022	Added reference to EFLH values in Appendix 2. EFLH value was previously missing.
52	1/14/2022	Fixed error under baseline efficiency, high efficiency, and references section. Document originally labelled the referenced code as “Massachusetts” building code, rather than “New Hampshire”. The referenced code, IECC 2015 Energy Conservation, and the values listed were correct but were incorrectly labelled with “Massachusetts”. Additionally, the reference to the code was updated as it was not included originally.

2.43 HVAC – Hotel Occupancy Sensor

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

The measure is to the installation of hotel occupancy sensors (HOS) to control packaged terminal AC units (PTACs) with electric heat, heat pump units and/or fan coil units in hotels that operate all 12 months of the year.

Baseline Efficiency:

The baseline efficiency case assumes the equipment has no occupancy-based controls.

High Efficiency:

The high efficiency case is the installation of controls that include (a) occupancy sensors, (b) window/door switches for rooms that have operable window or patio doors, and (c) set back to 65°F in the heating mode and set forward to 78°F in the cooling mode when occupancy detector is in the unoccupied mode. Sensors controlled by a front desk system are not eligible.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on evaluation results[1].

BC Measure ID	Measure Name	Program	ΔkWh	ΔkW
E21C1a031 E21C1d031 E21C2a031 E21C2d031 E21C3a050 E21C3d050	Hotel Occupancy Sensor	LBES Retro LBES DI SBES Retro SBES DI Muni Retrofit Muni DI	438	0.090

Measure Life:

The measure life is 10 years.[2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a031 E21C1d031	Hotel Occupancy Sensor	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.820	0.050
E21C2a031 E21C2d031	Hotel Occupancy Sensor	SBES Retro SBES DI	1.000	1.000	n/a	1.000	1.000	0.820	0.050
E21C3a050 E21C3d050	Hotel Occupancy Sensor	Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.820	0.050

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are 82.0% for summer peak and 5.0% for winter peak.[3]

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Heating and Cooling".

Endnotes:
1: MassSave, 2010. Energy Analysis: Hotel Guest Occupancy Sensors. Prepared for National Grid and Eversource (NSTAR).
2: Energy and Resource Solutions, November 2005. Measure Life Study. Prepared for MA Joint Utilities. HOS measure life assumed to be the same as that for occupancy-based lighting controls. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
3: New Hampshire Common Assumptions.

2.44 HVAC – Pipe Wrap

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

Pipe Wrap – Heating: Install insulation on steam pipes located in non-conditioned spaces.
Pipe Wrap – Hot Water: Install insulation on hot water heating pipes located in unconditioned spaces.

Baseline Efficiency:

Pipe Wrap – Heating: The baseline efficiency case is un-insulated steam piping in unconditioned space.
Pipe Wrap – Hot Water: The baseline efficiency case is un-insulated hot water heating piping in unconditioned space.

High Efficiency:

Pipe Wrap – Heating: The high efficiency condition is steam piping in unconditioned space with insulation installed.
Pipe Wrap – Hot Water: The high efficiency condition is hot water heating piping in unconditioned space with insulation installed.

Algorithms for Calculating Primary Energy Impact:

Gas unit savings are deemed based on study results.[1, 2] kW savings for hot water pipes with electric are calculated using the demand impact model.

Savings for steam pipes with electric heating is calculated as:

$$\Delta kWh = \frac{\left(\left(\frac{UA}{L}\right)_{baseline} - \left(\frac{UA}{L}\right)_{ee}\right)}{E_t \times 3{,}412} \times L \times \Delta T_{amb} \times hrs$$

Where,

$\left(\frac{UA}{L}\right)_{baseline}$ = Overall baseline heat transfer coefficient per unit length. 0.97 for 1.5”, 1.19 for 2”, and 1.70 for 3” copper pipes. For steel pipes, 1.23 for 1.5”, 1.51 for 2”, and 2.16 for 3”.

$\left(\frac{UA}{L}\right)_{ee}$ = Overall energy efficient heat transfer coefficient per unit length: 0.12 for all pipe sizes assuming fiber glass insulation of thickness equal to pipe diameter. Use 0.46 for rigid foam/cellular glass insulation of thickness equal to pipe diameter.

L = Length of the pipe insulated.

ΔT_{amb} = 85 °F.[1]
hrs = Annual operating hours.
E_t = Thermal efficiency of electric heater. Default value of 0.98.

$$\Delta kW = \frac{\Delta kWh}{8760}$$

Unit savings for gas measures are deemed based on an average of unit savings for 1.5 inch pipes and 3 inch pipes. [1]

Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu/ linera foot
G21C1a013 G21C2a013	Pipe Wrap – Heating	Gas	LBES Retro – Gas SBES Retro – Gas	n/a	n/a	.29[1]
G21C1a008 G21C2a008	Pipe Wrap – Hot Water	Gas	LBES Retro – Gas SBES Retro – Gas	n/a	n/a	.29[1]
E21C3a068 E21C3d068	Pipe Wrap – Heating	Gas	Muni Retro Muni DI	n/a	n/a	Calculated
E21C3a072 E21C3d072	Pipe Wrap – Hot Water	Gas	Muni Retro Muni DI	n/a	n/a	Calculated
E21C3a069 E21C3d069	Pipe Wrap – Heating	Oil	Muni Retro Muni DI	n/a	n/a	Calculated
E21C3a073 E21C3d073	Pipe Wrap – Hot Water	Oil	Muni Retro Muni DI	n/a	n/a	Calculated
E21C3a070 E21C3d070	Pipe Wrap – Heating	Propane	Muni Retro Muni DI	n/a	n/a	Calculated
E21C3a074 E21C3d074	Pipe Wrap – Hot Water	Propane	Muni Retro Muni DI	n/a	n/a	Calculated
E21C1a038 E21C1d038 E21C2a038 E21C2d038 E21C3a067 E21C3d067	Pipe Wrap – Heating	Electric	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	Calculated	Calculated	n/a
E21C1a039 E21C1d039 E21C2a039 E21C2d039 E21C3a071 E21C3d071	Pipe Wrap – Hot Water	Electric	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	Calculated	Calculated	n/a

Measure Life:

The measure life is 15 years.[3]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:[4]

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
G21C1a013 G21C2a013 E21C3a068 E21C3d068	Pipe Wrap – Heating	Gas	LBES Retro – Gas SBES Retro – Gas Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
G21C1a008 G21C2a008 E21C3a072 E21C3d072	Pipe Wrap – Hot Water	Gas	LBES Retro – Gas SBES Retro – Gas Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a069 E21C3d069	Pipe Wrap – Heating	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a073 E21C3d073	Pipe Wrap – Hot Water	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a070 E21C3d070	Pipe Wrap – Heating	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a074 E21C3d074	Pipe Wrap – Hot Water	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C1a038 E21C1d038	Pipe Wrap – Heating	Electric	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.000	0.433
E21C2a038 E21C2d038 E21C3a067 E21C3d067	Pipe Wrap – Heating	Electric	SBES Retro SBES DI Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.000	0.433
E21C1a039 E21C1d039	Pipe Wrap – Hot Water	Electric	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.312	0.808
E21C2a039 E21C2d039 E21C3a071 E21C3d071	Pipe Wrap – Hot Water	Electric	SBES Retro SBES DI Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.312	0.808

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% electric realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A summer coincidence factor of 31.2% and a winter coincidence factor of 80.8% is utilized for insulation of hot water pipes with electric heating. For heating pipes with electric heating, a winter coincidence factor of 43.3% is utilized.[4]

Energy Load Shape:

For electric heating measures, see Appendix 1 C&I Load Shapes "Hardwired Electric Heat".
For electric hot water measures, see Appendix 1 C&I Load Shapes "Water Heater – Electric".
For non-electric measures, see Appendix 1 C&I Load Shapes "Non-electric Measures"

Endnotes:
1: National Grid Staff Calculation, 2010. Pipe insulation for SBS DI measures 2010 Excel Workbook. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4885c6996f2d3357df744/view?authToken=962981283a7d38ac721edb179c5b7bf83c006a08da8c2f38866e381295963d8580eab751291c33061971c75a15dc0166f2c592d030d479cbaf9f7aa54c0ecbf2fc61aac2f00300
2: The Cadmus Group, July 2012. Massachusetts Multifamily Program Impact Analysis July 2012 – Revised May 2013. https://api-plus.anbetrack.com/etrm-gateway/etrm/api/v1/etrm/documents/5ee4885a6996f2cca27df73e/view?authToken=c3f41e9663355f5cba1ed024ab30ea4536bb2244f8e59bbbb2456444aad0600f2a7cd274d4a1ed7bdf33fa580f77ea7fb83e6341e0a43e7d5f9b52e5a311a397d19c852102c00d
3: Natural Gas Energy Efficiency Potential in Massachusetts. Prepared for GasNetworks, GDS Associates, April 2009. http://ma-eeac.org/wordpress/wp-content/uploads/5_Natural-Gas-EE-Potenial-in-MA.pdf
4: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

2.45 HVAC – Thermostat – Wi-Fi Communicating

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	HVAC

Description:

A Wi-Fi enabled communicating thermostat which allows remote set point adjustment and control via remote application. System requires an outdoor air temperature algorithm in the control logic to operate heating and cooling system.

Baseline Efficiency:

The baseline efficiency case is an HVAC system with either a manual or a programmable thermostat.

High Efficiency:

The high efficiency case is an HVAC system that has a Wi-Fi thermostat installed.

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on residential study results, adjusted for commercial buildings.[1]

BC Measure ID	Measure Name	Fuel Type	Program	ΔkWh	ΔkW	ΔMMBtu
E21C1a026 E21C1d028 E21C2a026 E21C2d028 E21C3a039 E21C3d041	Wi-Fi Thermostat	Electric	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	160.90	0.256	n/a
E21C3a040 E21C3d042 G21C1a016 G21C2a016	Wi-Fi Thermostat	Gas	Muni Retro Muni DI LBES Retro – Gas SBES Retro – Gas	n/a	n/a	3.11
E21C3a041 E21C3d043	Wi-Fi Thermostat	Oil	Muni Retro Muni DI	n/a	n/a	3.11
E21C3a042 E21C3d044	Wi-Fi Thermostat	Propane	Muni Retro Muni DI	n/a	n/a	3.11

Measure Life:

The measure life is 15 years.[2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel Type	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a026 E21C1d028	Wi-Fi Thermostat	Electric	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.346	0.000
E21C2a026 E21C2d028 E21C3a039 E21C3d041	Wi-Fi Thermostat	Electric	SBES Retro SBES DI Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.346	0.000
E21C3a040 E21C3d042 G21C1a016 G21C2a016	Wi-Fi Thermostat	Gas	Muni Retro Muni DI LBES Retro – Gas SBES Retro – Gas	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a041 E21C3d043	Wi-Fi Thermostat	Oil	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a
E21C3a042 E21C3d044	Wi-Fi Thermostat	Propane	Muni Retro Muni DI	1.000	n/a	1.000	n/a	n/a	n/a	n/a

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% electric realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Summer and winter Coincidence Factors are estimated using demand allocation methodology described the Demand Impact Model.[3]

Energy Load Shape:

See Appendix 1 "Weighted HVAC- All Homes"

Endnotes:
1: Navigant Consulting, September 2018. Wi-Fi Thermostat Impact Evaluation--Secondary Research Study Memo. https://ma-eeac.org/wp-content/uploads/Wi-Fi-Thermostat-Impact-Evaluation-Secondary-Literature-Study_FINAL.pdf

The residential savings values for Wi-Fi communicating thermostats recommended in the 2018 Secondary Research Study memo are applied to the commercial measures in this chapter as it has not been possible to document savings from commercial Wi-Fi communicating measures. The residential values are not scaled up as the savings from the commercial measures are expected to be very low.

2: Assumed to have the same lifetime as a regular programmable thermostat. Environmental Protection Agency, 2010. Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat.
3: Navigant Consulting, 2018. RES1 Demand Impact Model Update. http://ma-eeac.org/wordpress/wp-content/uploads/RES-1-FINAL-Comprehensive-Report-2018-07-27.pdf

2.46 HVAC – Unitary Air Conditioner

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

This measure promotes the installation of high efficiency unitary air conditioning equipment in lost opportunity applications. Air conditioning (AC) systems are a major consumer of electricity and systems that exceed baseline efficiencies can save considerable amounts of energy. This measure applies to air, water, and evaporatively-cooled unitary AC systems, both single-package and split systems.

Baseline Efficiency:

The baseline efficiency case for new installations assumes compliance with the efficiency requirements as mandated by New Hampshire State Building Code.

High Efficiency:

The high efficiency case assumes the HVAC equipment meets or exceeds the Consortium for Energy Efficiency's (CEE) specification. This specification results in cost-effective energy savings by specifying higher efficiency HVAC equipment while ensuring that several manufacturers produce compliant equipment. The CEE specification is reviewed and updated annually to reflect changes to the ASHRAE and IECC energy code baseline as well as improvements in the HVAC equipment technology. Equipment efficiency is the rated efficiency of the installed equipment for each project.

Algorithms for Calculating Primary Energy Impact:

For units with cooling capacities less than 65 kBtu/h:
$\Delta kWh = (kBtu/h)\ (1/\ SEER_{BASE} - 1/\ SEER_{EE})\ (EFLH_{Cool})$
$\Delta kW = (kBtu/h)\ (1/\ EER_{BASE} - 1/\ EER_{EE})$

For units with cooling capacities equal to or greater than 65 kBtu/h and EER available:
$\Delta kWh = (kBtu/h)\ (1/\ EER_{BASE} - 1/\ EER_{EE})\ (EFLH_{Cool})$
$\Delta kW = (kBtu/h)\ (1/\ EER_{BASE} - 1/\ EER_{EE})$

For units with cooling capacities equal to or greater than 65 kBtu/h and IEER available:
$\Delta kWh = (kBtu/h)\ (1/\ IEER_{BASE} - 1/\ IEER_{EE})\ (EFLH_{Cool})$
$\Delta kW = (kBtu/h)\ (1/\ EER_{BASE} - 1/\ EER_{EE})$

Where:
ΔkWh = Gross annual kWh savings from the measure
ΔkW = Gross connected kW savings from the measure

kBtu/h = Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h).
$SEER_{BASE}$ = Seasonal Energy Efficiency Ratio of the baseline equipment
$SEER_{EE}$ = Seasonal Energy Efficiency Ratio of the energy efficient equipment
$EFLH_{Cool}$ = Cooling equivalent full load hours from Appendix 2.
EER_{BASE} = Energy Efficiency Ratio of the baseline equipment*
EER_{EE} = Energy Efficiency Ratio of the energy efficient equipment*
$IEER_{BASE}$ = Integrated Energy Efficiency Ratio of the baseline equipment
$IEER_{EE}$ = Integrated Energy Efficiency Ratio of the energy efficient equipment

*If converting from SEER, please use the following equation: $EER = -0.02 \times SEER^2 + 1.12 \times SEER$. [1]

The baseline efficiency case for new installations assumes compliance with the efficiency requirements as mandated by IECC 2018.[1]

<table>
<tr><th>Equipment Type</th><th>Size Category</th><th>Heating Section Type</th><th>Subcategory or Rating Condition</th><th>Minimum Efficiency</th><th>Test Procedure</th></tr>
<tr><td rowspan="2">Air conditioners, air cooled</td><td rowspan="2">< 65,000 Btu/h</td><td rowspan="2">All</td><td>Split System</td><td>13.0 SEER</td><td rowspan="5">AHRI 210/240</td></tr>
<tr><td>Single Package</td><td>14.0 SEER</td></tr>
<tr><td rowspan="2">Through-the-wall (air cooled)</td><td rowspan="2">≤ 30,000 Btu/h</td><td rowspan="2">All</td><td>Split system</td><td>12.0 SEER</td></tr>
<tr><td>Single Package</td><td>12.0 SEER</td></tr>
<tr><td>Small duct high velocity, air cooled</td><td>≤ 65,000 Btu/h</td><td>All</td><td>Split system</td><td>11.0 SEER</td></tr>
<tr><td rowspan="6">Air conditioners, air cooled</td><td rowspan="2">≥ 65,000 Btu/h and < 135,000 Btu/h</td><td>Electric Resistance (or None)</td><td>Split System and Single Package</td><td>11.2 EER
12.9 IEER</td><td rowspan="6">AHRI 340/360</td></tr>
<tr><td>All other</td><td>Split System and Single Package</td><td>11.0 EER
12.7 IEER</td></tr>
<tr><td rowspan="2">≥ 135,000 Btu/h and < 240,000 Btu/h</td><td>Electric Resistance (or None)</td><td>Split System and Single Package</td><td>11.0 EER
12.4 IEER</td></tr>
<tr><td>All other</td><td>Split System and Single Package</td><td>10.8 EER
12.2 IEER</td></tr>
<tr><td rowspan="2">≥ 240,000 Btu/h and < 760,000 Btu/h</td><td>Electric Resistance (or None)</td><td>Split System and Single Package</td><td>10.0 EER
11.6 IEER</td></tr>
<tr><td>All other</td><td>Split System and Single Package</td><td>9.8 EER
11.4 IEER</td></tr>
</table>

Equipment Type	Size Category	Heating Section Type	Subcategory or Rating Condition	Minimum Efficiency	Test Procedure
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	9.7 EER 11.2 IEER	
		All other	Split System and Single Package	9.5 EER 11.0 IEER	
Air conditioners, water cooled	< 65,000 Btu/h	All	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 210/240
	≥ 65,000 Btu/h and < 135,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.1 EER 13.9 IEER	AHRI 340/360
		All other	Split System and Single Package	11.9 EER 13.7 IEER	
	≥ 135,000 Btu/h and < 240,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.5 EER 13.9 IEER	
		All other	Split System and Single Package	12.3 EER 13.7 IEER	
	≥ 240,000 Btu/h and < 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.4 EER 13.6 IEER	
		All other	Split System and Single Package	12.2 EER 13.4 IEER	
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.2 EER 13.5 IEER	
		All other	Split System and Single Package	12.0 EER 13.3 IEER	
Air conditioners, evaporatively cooled	< 65,000 Btu/h	All	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 210/240
	≥ 65,000 Btu/h and < 135,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 340/360
		All other	Split System and Single Package	11.9 EER 12.1 IEER	
	≥ 135,000 Btu/h and < 240,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.0 EER 12.2 IEER	

Equipment Type	Size Category	Heating Section Type	Subcategory or Rating Condition	Minimum Efficiency	Test Procedure
		All other	Split System and Single Package	11.8 EER 12.0 IEER	
	≥ 240,000 Btu/h and < 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.9 EER 12.1 IEER	
		All other	Split System and Single Package	11.7 EER 11.9 IEER	
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.7 EER 11.9 IEER	
		All other	Split System and Single Package	11.5 EER 11.7 IEER	
Condensing units, air cooled	≥ 135,000 Btu/h			10.5 EER 11.8 IEER	AHRI 365
Condensing units, water cooled	≥ 135,000 Btu/h			13.5 EER 14.0 IEER	
Condensing units, evaporatively cooled	≥ 135,000 Btu/h			13.5 EER 14.0 IEER	

Equipment Type	Size Category	Heating Section Type	Subcategory or Rating Condition	Minimum Efficiency	Test Procedure
Air conditioners, air cooled	< 65,000 Btu/h	All	Split System	13.0 SEER	AHRI 210/240
			Single Package	14.0 SEER	
Through-the-wall (air cooled)	≤ 30,000 Btu/h	All	Split system	12.0 SEER	
			Single Package	12.0 SEER	
Small duct high velocity, air cooled	≤ 65,000 Btu/h	All	Split system	11.0 SEER	
Air conditioners, air cooled	≥ 65,000 Btu/h and < 135,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.2 EER 12.9 IEER	AHRI 340/360
		All other	Split System and Single Package	11.0 EER 12.7 IEER	
	≥ 135,000 Btu/h and < 240,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.0 EER 12.4 IEER	

Equipment Type	Size Category	Heating Section Type	Subcategory or Rating Condition	Minimum Efficiency	Test Procedure
		All other	Split System and Single Package	10.8 EER 12.2 IEER	
	≥ 240,000 Btu/h and < 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	10.0 EER 11.6 IEER	
		All other	Split System and Single Package	9.8 EER 11.4 IEER	
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	9.7 EER 11.2 IEER	
		All other	Split System and Single Package	9.5 EER 11.0 IEER	
Air conditioners, water cooled	< 65,000 Btu/h	All	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 210/240
	≥ 65,000 Btu/h and < 135,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.1 EER 13.9 IEER	AHRI 340/360
		All other	Split System and Single Package	11.9 EER 13.7 IEER	
	≥ 135,000 Btu/h and < 240,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.5 EER 13.9 IEER	
		All other	Split System and Single Package	12.3 EER 13.7 IEER	
	≥ 240,000 Btu/h and < 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.4 EER 13.6 IEER	
		All other	Split System and Single Package	12.2 EER 13.4 IEER	
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.2 EER 13.5 IEER	
		All other	Split System and Single Package	12.0 EER 13.3 IEER	
	< 65,000 Btu/h	All	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 210/240

Equipment Type	Size Category	Heating Section Type	Subcategory or Rating Condition	Minimum Efficiency	Test Procedure
Air conditioners, evaporatively cooled	≥ 65,000 Btu/h and < 135,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.1 EER 12.3 IEER	AHRI 340/360
		All other	Split System and Single Package	11.9 EER 12.1 IEER	
	≥ 135,000 Btu/h and < 240,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	12.0 EER 12.2 IEER	
		All other	Split System and Single Package	11.8 EER 12.0 IEER	
	≥ 240,000 Btu/h and < 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.9 EER 12.1 IEER	
		All other	Split System and Single Package	11.7 EER 11.9 IEER	
	≥ 760,000 Btu/h	Electric Resistance (or None)	Split System and Single Package	11.7 EER 11.9 IEER	
		All other	Split System and Single Package	11.5 EER 11.7 IEER	
Condensing units, air cooled	≥ 135,000 Btu/h			10.5 EER 11.8 IEER	AHRI 365
Condensing units, water cooled	≥ 135,000 Btu/h			13.5 EER 14.0 IEER	
Condensing units, evaporatively cooled	≥ 135,000 Btu/h			13.5 EER 14.0 IEER	

Measure Life:

The measure life is 12 years. [2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b049	Unitary Air Conditioner	LBES New	1.000	0.999	n/a	1.000	1.000	0.342	0.000
E21C2b049	Unitary Air Conditioner	SBES New	1.000	1.000	n/a	1.000	1.000	0.342	0.000
E21C3b080	Unitary Air Conditioner	Muni New	1.000	1.000	n/a	1.000	1.000	0.342	0.000
E21C1c007	Midstream Unitary Air Conditioners	LBES Midstream	1.000	1.000	n/a	1.000	1.000	0.342	0.000
E21C2c007	Midstream Unitary Air Conditioners	SBES Midstream	1.000	1.000	n/a	1.000	1.000	0.342	0.000

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

A summer coincidence factor of 34.2% is utilized.[3]

Energy Load Shape:

See Appendix 1 C&I Load Shapes “C&I Electric Cooling Unitary Equipment”.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[4]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c007 E21C2c007	Midstream Unitary Air Conditioners	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.86

Endnotes:
1: Equation used by NREL Building America House Simulation Protocols. https://www.nrel.gov/docs/fy11osti/49246.pdf
2: 2018 IECC
3: KEMA, August 2011. C&I Unitary HVAC Loadshape Project Table 0-5 (ISO_NE on Peak for NE-North)
https://neep.org/sites/default/files/resources/NEEP_HVAC_Load_Shape_Report_Final_August2_0.pdf

4: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

Revision History:

Revision Number	Date	Revision
54	1/14/2022	Updated baseline table for clarity and to reference most recent code.
69	3/1/2022	Added EFLH reference to Appendix 2

2.47 HVAC – Heat Pump Systems

Measure Code	[Code]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	HVAC

Description:

This measure includes the installation of ductless mini split, ground source and water source heat pumps to serve the space heating and space cooling loads in a C&I facility. "Water source" refers to systems that use ground or lake water rather than a boiler as a loop heat source. The savings for this measure are realized through the increased nameplate efficiency between the baseline and installed equipment.

Baseline Efficiency:

For lost opportunity, the baseline is a code compliant heat pump unit of the same type as the high efficiency unit. Details regarding heat pump baseline efficiencies based on capacity and type are provided in a tabular format along with the savings algorithms.

For early retirement (retrofit), it is assumed that the new unit replaces the pre-existing heat pump unit, which is not at the end of its useful life. In this case, the baseline is the pre-existing, inefficient heat pump unit.

High Efficiency:

The high efficiency (or energy efficient) case is the site-specific heat pump unit. The energy efficient heat pump unit is assumed to be of the same type as the baseline unit.

Algorithms for Calculating Primary Energy Impact:

The savings for this measure are attributable to the increase in nameplate efficiency between the baseline and installed units.
The algorithm for calculating electric demand savings is:

$$\Delta kW = \Delta kW_{cool} + \Delta kW_{heat}$$

$$\Delta kW_{cool} = Cap_{cool} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

$$\Delta kW_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right)$$

$Cap_{heat} = Cap_{cool} \times 1.0$ if unit is a cold climate ductless mini split heat pump

$Cap_{heat} = Cap_{cool} \times 0.9$ for all other ductless mini split heat pump

$Cap_{heat} = Cap_{cool} \times \left(\frac{HSPF_{EE}}{EER_{EE}}\right)$ for water source and ground source heat pumps

The algorithm for calculating annual electric energy savings is:

$$\Delta kWh = \Delta kWh_{cool} + \Delta kWh_{heat}$$

For ductless mini split heat pumps

$$\Delta kWh_{cool} = Cap_{cool} \times \left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right) \times EFLH_{cool}$$

$$\Delta kWh_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right) \times EFLH_{heat}$$

For water source and ground source heat pumps

$$\Delta kWh_{cool} = Cap_{cool} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right) \times EFLH_{cool}$$

$$\Delta kWh_{heat} = Cap_{heat} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right) \times EFLH_{heat}$$

Where:
ΔkW = Gross annual demand savings for heat pump unit
ΔkW_{cool} = Gross annual cooling demand savings for heat pump unit
ΔkW_{heat} = Gross annual heating demand savings for heat pump unit. For non cold-climate ductless mini-split heat pump OR for facilities that employ supplemental heating sources (such as fossil fuel or electric resistance heat), ΔkW_{heat} = 0
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient heat pump unit, from equipment specifications
Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient pump unit, from equipment specifications. Use given equations to convert from cooling capacity value if standard equipment literature does not provide this value
EER_{BASE} = Energy Efficiency Ratio of the baseline heat pump equipment
EER_{EE} = Energy Efficiency Ratio of the energy efficient heat pump unit, from equipment specifications
$HSPF_{BASE}$ = Heating Seasonal Performance Factor of baseline heat pump equipment
$HSPF_{EE}$ = Heating Seasonal Performance Factor of energy efficient heat pump unit, from equipment specifications

ΔkWh_{cool} = Gross annual cooling savings for heat pump unitΔkWh_{heat} = Gross annual heating savings for heat pump unit

$SEER_{BASE}$ = Seasonal Energy Efficiency Ratio of baseline heat pump equipment
$SEER_{EE}$ = Seasonal Energy Efficiency Ratio of energy efficient heat pump unit, from equipment specifications
$EFLH_{cool}$ = Equivalent Full Load Hours for cooling. Refer to Appendix 2 for inputs.
$EFLH_{heat}$ = Equivalent Full Load Hours for heating. Refer to Appendix 2 for inputs.
0.9 = Conversion factor[1] to convert cooling capacity to heating capacity for ductless mini split heat pump units not on NEEP's cold climate air source heat pump (ccASHP) product list. The conversion factor for ccASHPs is 1.0.

Heat Pump Type	Cooling Capacity Range	Parameter	Value (Lost Opportunity)	Value (Retrofit)	Units
Ductless Mini Split	≤65,000 Btu/h	EER_{BASE}	11.76[2]	Pre-existing equipment EER	Btu/W-h
		$SEER_{BASE}$	14.00[3]	Pre-existing equipment SEER	Btu/W-h
		$HSPF_{BASE}$	8.20[3]	Pre-existing equipment HSPF	Btu/W-h
Water Source	<17,000 Btu/h	EER_{BASE}	12.20[3]	Pre-existing equipment EER	Btu/W-h
		$HSPF_{BASE}$	14.67[3]	Pre-existing equipment HSPF	Btu/W-h
	≥17,000 Btu/h	EER_{BASE}	13.00[3]	Pre-existing equipment EER	Btu/W-h
		$HSPF_{BASE}$	14.67[3]	Pre-existing equipment HSPF	Btu/W-h
Ground Source (Open Loop)	All Sizes	EER_{BASE}	18.00[3]	Pre-existing equipment EER	Btu/W-h
		$HSPF_{BASE}$	12.62[3]	Pre-existing equipment HSPF	Btu/W-h
Ground Source (Closed Loop)	All Sizes	EER_{BASE}	14.1[3]	Pre-existing equipment EER	Btu/W-h
		$HSPF_{BASE}$	10.91[3]	Pre-existing equipment HSPF	Btu/W-h
All		$HSPF_{BASE}$	3.142 For when baseline/pre-existing system is electric resistance heat		Btu/W-h
All		$EFLH_{cool}$	755[4]		hours
		$EFLH_{heat}$	1329[4]		hours

Measure Life:

The measure life is listed below by measure. Due to limitations with the avoided cost calculations in the Benefit/Cost Models, where measure lives are greater than 25 years, the models use a 25-year measure life.

BC Measure ID	Measure Name	Program	Measure Life
E21C1a022	Ductless Mini Split Heat Pump	LBES Retrofit	12[5]
E21C1d024	Ductless Mini Split Heat Pump	LBES DI	12[5]
E21C2a022	Ductless Mini Split Heat Pump	SBES Retrofit	12[5]
E21C2d024	Ductless Mini Split Heat Pump	SBES DI	12[5]
E21C3a035	Ductless Mini Split Heat Pump	Muni Retrofit	12[5]
E21C3d037	Ductless Mini Split Heat Pump	Muni DI	12[5]
E21C1b050	Water Source Heat Pump	LBES New	26[6]
E21C2b050	Water Source Heat Pump	SBES New	26[6]
E21C3b081	Water Source Heat Pump	Muni New	26[6]
E21C1b035	Ground Source Heat Pump	LBES New	26[6]
E21C2b035	Ground Source Heat Pump	SBES New	26[6]
E21C3b056	Ground Source Heat Pump	Muni New	26[6]
E21C1c003	Midstream DMSHP Systems	LBES Midstream	12[5]
E21C2c003	Midstream DMSHP Systems	SBES Midstream	12[5]
E21C1c006	Midstream Heat Pump Systems	LBES Midstream	12[5]
E21C2c006	Midstream Heat Pump Systems	SBES Midstream	12[5]
E21C1c009	Midstream Water Source Heat Pump Systems	LBES Midstream	26[6]
E21C2c009	Midstream Water Source Heat Pump Systems	SBES Midstream	26[6]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a022	Ductless Mini Split Heat Pump	LBES Retrofit	1.000	0.999	1.000	1.000	1.000	0.342	0.000

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1d024	Ductless Mini Split Heat Pump	LBES DI	1.000	0.999	1.000	1.000	1.000	0.342	0.000
E21C2a022	Ductless Mini Split Heat Pump	SBES Retrofit	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C2d024	Ductless Mini Split Heat Pump	SBES DI	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C3a035	Ductless Mini Split Heat Pump	Muni Retrofit	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C3d037	Ductless Mini Split Heat Pump	Muni DI	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C1b050	Water Source Heat Pump	LBES New	1.000	0.999	1.000	1.000	1.000	0.342	0.342
E21C2b050	Water Source Heat Pump	SBES New	1.000	1.000	1.000	1.000	1.000	0.342	0.342
E21C3b081	Water Source Heat Pump	Muni New	1.000	1.000	1.000	1.000	1.000	0.342	0.342
E21C1b035	Ground Source Heat Pump	LBES New	1.000	0.999	1.000	1.000	1.000	0.342	0.342
E21C2b035	Ground Source Heat Pump	SBES New	1.000	1.000	1.000	1.000	1.000	0.342	0.342
E21C3b056	Ground Source Heat Pump	Muni New	1.000	1.000	1.000	1.000	1.000	0.342	0.342
E21C1c003	Midstream DMSHP Systems	LBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C2c003	Midstream DMSHP Systems	SBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C1c006	Midstream Heat Pump Systems	LBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C2c006	Midstream Heat Pump Systems	SBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.000
E21C1c009	Midstream Water Source Heat Pump Systems	LBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.342
E21C2c009	Midstream Water Source Heat Pump Systems	SBES Midstream	1.000	1.000	1.000	1.000	1.000	0.342	0.342

In-Service Rates:

All installations have 100.0% in-service-rates since programs include verification of equipment installations.

Realization Rates[7]:

All programs use 100.0% realization rate except for LBES (Retrofit, Direct Install, and NEC), which use a value of 99.9%.

Coincidence Factors[8]:

For ductless mini split heat pumps, summer coincidence factor is 34.2% and a winter coincidence factor is 0%.
For cold-climate ductless mini split heat pumps, is 34.2% and a winter coincidence factor is 34.2%.
For water source heat pumps and ground source heat pumps, summer & winter coincidence factor is 34.2%.

Energy Load Shape:

For ductless mini split heat pumps, see Appendix 1 – "DMSHP"
For water source and ground source heat pumps, see Appendix 1 – "Central Heat Pump"

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[9]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c003 E21C2c003	Midstream DMSHP Systems	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860
E21C1c006 E21C2c006	Midstream Heat Pump Systems	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860
E21C1c009 E21C2c009	Midstream Water Source Heat Pump Systems	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860

Endnotes:
1: Conversion factor is based on internal ERS analysis of Mass Save and NEEP ccASHP product data.
2: Since IECC does not provide EER requirements for heat pumps <65kBtu/h, the following conversion is used: $EER = -0.02 \times SEER^2 + 1.12 \times SEER$. Source for the calculation is https://www.nrel.gov/docs/fy11osti/49246.pdf3: International Energy Conservation Code 2015, table C403.2.3(2) Minimum Efficiency Requirements: Electrically Operated Unitary and Applied Heat Pumps
4: KEMA((2011). C&I Unitary AC Loadshape Project - Final Report. KEMA_2011_CI Unitary HVAC Load Shape Project
5: DNV GL (2018). Expected Useful Life (EUL) Estimation for Air-Conditioning Equipment from Current Age Distribution Memo. https://ma-eeac.org/wp-content/uploads/Final-memo-on-P73-Track-D-EUL-estimation-results-to-date-v2.pdf

6:http://weblegacy.ashrae.org/publicdatabase/system_service_life.asp?c_region=2&state=NA&building_function=NA&c_size=0&c_age=0&c_height=0&c_class=0&c_location=0&selected_system_type=1&c_equipment_type=NA. . See mean age of replaced water-to-air, geothermal heat pumps
7: New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Impact Evaluation report. Table 3
8. Coincidence Factors are from 2011 NEEP HVAC Loadshape Study Table 0-5 (ISO_NE on Peak for NE-North)
9: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

Revision Number	Date	Revision
55	1/14/2022	Updated SEER to EER conversion factor
72	3/1/2022	Added EFLH values.

2.48 HVAC – VRF Systems

Measure Code	[Code]
Market	Commercial
Program Type	Lost Opportunity
Category	HVAC

Description:

This measure includes in the installation of high-efficiency variable flow refrigerant (VRF) heat pumps.

Baseline Efficiency:

The baseline is a code compliant VRF heat pump unit. Details regarding heat pump baseline efficiencies based on capacity and type are provided in a tabular format along with the savings algorithms.

High Efficiency:

The high efficiency case is the site-specific VRF heat pump unit.

Algorithms for Calculating Primary Energy Impact:

The savings for this measure are attributable to the increase in nameplate efficiency between the baseline and installed units.

The algorithm for calculating electric demand savings is: :

$$\Delta kW = Cap_{cool} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

Where:
ΔkW = Gross annual demand savings for VRF unit
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient VRF unit, from equipment specifications
EER_{BASE} = Energy Efficiency Ratio of the baseline VRF equipment
EER_{EE} = Energy Efficiency Ratio of the energy efficient VRF unit, from equipment specifications

The algorithm for calculating annual electric energy savings is:

$$\Delta kWh = \Delta kWh_{cool} + \Delta kWh_{heat}$$

$$\Delta kWh_{cool} = Cap_{cool} \times \left(\frac{1}{IEER_{BASE}} - \frac{1}{IEER_{EE}}\right) \times EFLH_{cool}$$

$$\Delta kWh_{heat} = \frac{Cap_{heat}}{3.412} \times \left(\frac{1}{COP_{BASE}} - \frac{1}{COP_{EE}}\right) \times EFLH_{heat}$$

Where:
ΔkWh_{cool} = Gross annual cooling savings for VRF unit
ΔkWh_{heat} = Gross annual heating savings for VRF unit
Cap_{cool} = Cooling capacity (in kBtu/h) of the energy efficient VRF unit, from equipment specifications
Cap_{heat} = Heating capacity (in kBtu/h) of the energy efficient VRF unit, from equipment specifications.
$IEER_{BASE}$ = Integrated Energy Efficiency Ratio of baseline VRF equipment
$IEER_{EE}$ = Integrated Energy Efficiency Ratio of energy efficient VRF unit
COP_{BASE} = Coefficient of performance in heating mode of baseline VRF equipment
COP_{EE} = Coefficient of performance in heating mode of energy efficient VRF unit
$EFLH_{cool}$ = Cooling equivalent full load hours from Appendix 2.
$EFLH_{hjeat}$ = Heating equivalent full load hours from Appendix 2.

VRF System Type	Parameter	Value[1]
Air Cooled	EER_{BASE}	11
	$IEER_{BASE}$	12.9
	COP_{BASE}	3.3
Water Cooled	EER_{BASE}	12
	$IEER_{BASE}$	16.0
	COP_{BASE}	4.2

Measure Life:

The measure life is 12 years.[2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c008 E21C2c008	Midstream VRF	LBES Midstream SBES Midstream	1.000	1.000	n/a	1.000	1.000	0.342	0.000

In-Service Rates:

All installations have a 100.0% in-service rate unless an evaluation finds otherwise.

Realization Rates:

All installations have a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

The summer coincidence factor is 34.2% and the winter coincidence factor is 0%.[3]

Energy Load Shape:

See Appendix 1 – "Central Heat Pump".

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[4]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c008 E21C2c008	Midstream VRF	LBES Midstream SBES Midstream	0.225	0.085	0.000	0.860

Endnotes:
1: ANSI/ASHRAE/IES Standard 90.1-2013. Table 6.8.1-10
2: Energy & Resource Solutions, November. Measure Life Study. Prepared for The Massachusetts Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
3. Coincidence Factors are from 2011 NEEP HVAC Loadshape Study Table 0-5 (ISO_NE on Peak for NE-North)
4: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf

2.49 Refrigeration – Cooler Night Cover

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of retractable aluminium woven fabric covers for open type refrigerated display cases, where the covers are deployed during the facility unoccupied hours in order to reduce refrigeration energy consumption.

Baseline Efficiency:

The baseline efficiency case is the annual operation of open-display cooler cases.

High Efficiency:

The high efficiency case is the use of night covers to protect the exposed area of display cooler cases during unoccupied hours.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = (Width) \times (Save) \times (Hours)$
$\Delta kW = (Width) \times (Save)$

Where:
ΔkWh = Energy Savings
ΔkW = Connected load reduction
Width = Width of the opening that the night covers protect (ft)
Save = Savings factor based on the temperature of the case (kW/ft). See table below [1]
Hours = Annual hours that the night covers are in use

Cooler Case Temperature	Savings Factor
Low Temperature (-35 F to -5 F)	0.03 kW/ft
Medium Temperature (0 F to 30 F)	0.02 kW/ft
High Temperature (35 F to 55 F)	0.01 kW/ft

Measure Life:

The measure life for refrigeration add-on measures are 10 years. [2]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a017 E21C1d019	Cooler Night Covers	LBES Retro LBES DI	1.000	0.999	n/a	1.000	1.000	0.000	0.000
E21C2a017 E21C2d019	Cooler Night Covers	SBES Retro SBES DI	1.000	1.000	n/a	1.000	1.000	0.000	0.000
E21C3a023 E21C3d025	Cooler Night Covers	Muni Retro Muni DI	1.000	1.000	n/a	1.000	1.000	0.000	0.000

In-Service Rates:

All installations have 100% in-service rate since all programs require verification of equipment installation.

Realization Rates:

Large Business Energy Solution uses a 99.9% realization rate. All other programs use a 100.0% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are 0.0% since night cover usage occurs outside of peak demand hours.

Energy Load Shape:

See Appendix 1 C&I Load Shapes– "C&I Refrigeration".

Endnotes:

1: CL&P Program Savings Documentation for 2011 Program Year, 2010. Factors based on Southern California Edison (1997). Effects of the Low Emissive Shields on Performance and Power Use of a Refrigerated Display Case. https://www.econofrost.com/wp-content/uploads/2016/03/Ashrae.pdf

2: Energy & Resource Solutions, November 2005. Measure Life Study. Prepared for The Massachusetts Joint Utilities; Page 4-5 to 4-6. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf

2.50 Lighting – Controls

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Lighting

Description:

This measure includes the installation of lighting controls in both lost-opportunity and retrofit applications. Occupancy sensors and daylight dimming controls are both included. Traffic-sensing occupancy sensors that control refrigerated case LEDs are also included as a separate section.

Baseline Efficiency:

The baseline efficiency case for retrofit applications is no controls.

The baseline efficiency case for new construction is code-compliant controls as mandated by the New Hampshire Building Code, which currently reflects IECC 2015 and ASHRAE Standard 90.1-2013.

The baseline efficiency case for refrigerated case LEDs is no controls.

High Efficiency:

The high efficiency case for retrofit applications is lighting fixtures connected to controls that reduce the pre-retrofit hours of operation.

The high efficiency case for new construction applications is lighting fixture controls that reduce the hours of operation further beyond code-compliant controls.

The high efficiency case for refrigerated case LEDs is traffic-sensing controls that are mounted on cases to dim case lighting from a high level to a low-power mode (assumed to be 25% of full power consumption) in less than 2 minutes when on traffic is sensed in the aisle.

Algorithms for Calculating Primary Energy Impact:

<u>For retrofit applications:</u>
ΔkWh = Controlled_kW × Hours_base × (%_sav)
ΔkW = (Controlled_kW)

Where:
Controlled_kW = controlled fixture wattage
Hours_base = total annual hours that the connected kW operated in the pre-retrofit case
%_sav = percentage of kWh that is saved by utilizing this control measure, as shown in the study-informed deemed savings table below.[1]

Control Type	% Savings Factor
Lighting Controls – Daylighting Dimming	0.28
Lighting Controls – Occupancy Sensor	0.24
Lighting Controls - Integral Dual Sensor	0.30
Lighting Controls - Integral Dual Sensors with Adaptive, Network-Capable Controls	0.35
Lighting Controls - Exterior Photocell	0.50

For lost opportunity applications:
$\Delta kWh = Controlled\_kW \times (Hours\_base - Hours\_ee)$
$\Delta kW = (Controlled\_kW)$

Where:
Controlled_kW = controlled fixture wattage
Hours_base = total annual hours that the connected Watts would have operated with code-compliant controls
Hours_ee = total annual hours that the connected kW operate with controls implemented, as determined on a per-application basis.

For refrigerated case LED controls:
$\Delta kWh = \Delta kWh\_lights + \Delta kWh\_refg$
$\Delta kWh\_lights = \Delta kW\_lights \times Hours$
$\Delta kW\_lights = kW\_hi - (0.85 \times kW\_hi + 0.15 \times kW\_lo)$
$\Delta kWh\_refg = \Delta kWh\_lights \times 0.28 \times Eff\_RS$

Where:
ΔkWh_lights = the lighting equipment contribution to savings
ΔkWh_refg = refrigeration interactive effects
kW_hi = the high-level lighting power per case, with deemed values shown in the table below
kW_lo = the low-level lighting power per case, with deemed values shown in the table below
Hours = the number of operating hours at the site, from application or deemed value shown in table below
0.85 = deemed fraction of time at high power[3]
0.15 = deemed fraction of time at low power[3]
0.28 = unit conversion between kW and tons of refrigeration
Eff_RS = efficiency of typical refrigeration system, with deemed values shown in the table below

Input	System type	Deemed Value	Unit	Source
kW_hi	5’ case side mounted	13	W	4
	5’ case center mounted	26	W	
	6’ case side mounted	16	W	
	6’ case center mounted	32	W	
kW_lo	5’ case side mounted	8.5	W	4
	5’ case center mounted	17	W	
	6’ case side mounted	11	W	
	6’ case center mounted	21	W	

Hours, if not available from site	All	4,910	Hr/yr	4
Eff_RS	Small business	1.6	kW/ton	5
	Large business	1.9	kW/ton	

Measure Life:

The table below provides measure life for control measures.[2,3]

BC Measure ID	Measure Name	Program	Measure Life
E21C1a009 E21C1d011 E21C2a009 E21C2d011 E21C3a009 E21C3d011	Daylight Dimming	LBES Retrofit, LBES DI, SBES Retrofit, SBES DI, MES Retrofit, MES DI	9
E21C1b009 E21C2b009 E21C3b009	Daylight Dimming	LBES New, SBES New, MES New	10
E21C1a014 E21C1d016 E21C2a014 E21C2d016 E21C3a014 E21C3d016	Lighting Occupancy Sensors	LBES Retrofit, LBES DI, SBES Retrofit, SBES DI, MES Retrofit, MES DI	9
E21C1b014 E21C2b014 E21C3b014	Lighting Occupancy Sensors	LBES New, SBES New, MES New	10

Other Resource Impacts:

Heating penalties for large C&I occupancy sensors are from a 12-month MA data logging study.[4] Penalties for small business and municipal programs are from the 2018 MA small business lighting impact evaluation.[6]

BC Measure ID	Measure Name	Program	MMBtu/kWh
E21C1a009 E21C1b009 E21C1d011	Daylight Dimming	LBES	-0.002728
E21C2a009 E21C2b009 E21C2d011 E21C3a009 E21C3b009 E21C3d011	Daylight Dimming	SBES, MES	-0.004080
E21C1a014 E21C1b014 E21C1d016	Lighting Occupancy Sensors	LBES	-0.002728
E21C2a014 E21C2b014 E21C2d016 E21C3a014 E21C3b014 E21C3d016	Lighting Occupancy Sensors	SBES, MES	-0.004080

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a009 E21C1b009 E21C1d011	Daylight Dimming	LBES	1.000	0.999	1.000	1.000	1.000	0.138	0.134
E21C1a014 E21C1b014 E21C1d016	Lighting Occupancy Sensors	LBES	1.000	0.999	1.000	1.000	1.000	0.138	0.134
E21C2a009 E21C2b009 E21C2d011 E21C3a009 E21C3b009 E21C3d011	Daylight Dimming	SBES, MES	1.000	1.000	1.000	1.000	1.000	0.170	0.130
E21C2a014 E21C2b014 E21C2d016 E21C3a014 E21C3b014 E21C3d016	Lighting Occupancy Sensors	SBES, MES	1.000	1.000	1.000	1.000	1.000	0.180	0.130

<u>In-Service Rates:</u>

All installations have a 100% in-service-rate unless an evaluation finds otherwise.

Realization Rates:

Realization rates are 100% until evaluated. NH evaluations that have sampled a non-statistically significant number of lighting controls projects produced realization rates slightly greater than 100%, including for Large Business custom electric sites and Small Business and Municipal lighting projects, some of which included controls.[8, 9]
For refrigerated case lighting controls, realization rates are defaulted to 100% as the cited research for savings calculations is a study, and not an evaluation.[3]

Coincidence Factors:

Summer and winter coincidence factors for small business and municipal programs are based on a MA study of lighting occupancy sensors in small businesses.[5] For large businesses, coincidence factors are based on a MA impact evaluation of the large C&I prescriptive lighting program.[4]

Impact Factors for Calculating Net Savings[10]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1a009 E21C1b009 E21C1d011 E21C2a009 E21C2b009 E21C2d011 E21C3a009 E21C3b009 E21C3d011	Daylight Dimming	LBES, SBES, MES	16%	5%	0%	89%
E21C1a014 E21C1b014 E21C1d016 E21C2a014 E21C2b014 E21C2d016 E21C3a014 E21C3b014 E21C3d016	Lighting Occupancy Sensors	LBES, SBES, MES	16%	5%	0%	89%

Energy Load Shape:

Energy load shapes are based on site-level metering of project sites in MA.[7]

Measure Name	Summer On-peak	Winter On-peak	Summer Off-peak	Winter Off-peak
Interior Lighting	34.3%	30.3%	18.1%	17.4%
Exterior Lighting	19.2%	20.1%	29.0%	31.6%

Endnotes:

1: DNV KEMA, October 27, 2014. Retrofit Lighting Controls Measures Summary of Findings. Final Report. (MA). https://ma-eeac.org/wp-content/uploads/Lighting-Retrofit-Control-Measures-Final-Report.pdf (NOTE: Report applies to daylight dimming and occupancy sensors. Dual sensor control savings factors are engineering calculated. Exterior controls factor only apply to On/Off photocells for lighting systems that operate on 24 hours per day, 7 days per week. Exterior controls with bi-level occupancy, dimming functions, or any other advanced/networked controls would receive a <0.50 savings factor in accordance with the table provided. Savings for integral occupancy sensors for high bay fixtures are custom calculated.)
2: ERS, November 17, 2005. Measure Life Study. Prepared for MA Joint Utilities. https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf
3: Southern California Edison, January 2016. Refrigerated Case Door Aisle Traffic Sensor. Work paper SCE13CS003, revision 2.. http://www.deeresources.net/workpapers
4: DNV KEMA, June 21, 2013. Impact Evaluation of 2010 Prescriptive Lighting Installations. (MA) https://ma-eeac.org/wp-content/uploads/Impact-Evaluation-of-2010-Prescriptive-Lighting-Installations-Final-Report-6-21-13.pdf
5: Cadmus Group, October 23, 2012. Small Business Direct Install Program: Pre/Post Lighting Occupancy Sensor Study. (MA) Available as appendix C-1 in https://ma-eeac.org/wp-content/uploads/Massachusetts-Small-Business-Direct-Install_2010-2012-Impact-Evaluations-1.29.13.pdf
6: DNV GL, ERS, June 7, 2018. Impact Evaluation of PY2016 Small Business Initiative: Phase I https://ma-eeac.org/wp-content/uploads/P69-Impact-Eval-of-MA-Small-Business-Initiative-Phase-I-Lighting_Report_FINAL.pdf
7: DNV GL, 2018. P72 Prescriptive C&I Loadshapes of Savings.
8: DNV GL, June 21, 2018. Impact Evaluation of 2016 New Hampshire Commercial & Industrial Small Business and Municipal Lighting. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/small-business-and-municipal-lighting-impact-evaluation.pdf. See sample projects including controls, which produced an overall realization rate of 106.6%.
9: DNV GL, September 25, 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf See 100.8% realization rate for custom electric measures in table 16.
10: EMI, September 25, 2019 . C1644 EO Net-to-Gross Study, Final Report. https://www.energizect.com/sites/default/files/C1644%20-%20EO%20NTG%20Final%20Report_9.25.19.pdf
Downstream NTG values are based on Energy Opportunities NTG Study Results for Lighting shown in Table ES-1-1 on p. ES-3.

Revision Number	Issue Date	Description
59	1/14/2022	Measure life for retrofit lighting occupancy sensors was updated to 9 years from 10, according to the cited ERS study. Original value was incorrect.

2.51 Lighting - Retrofit

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Lighting

Description:

This measure includes efficient lighting products including, but not limited to, efficient Light-Emitting Diode (LED) lamps and fixtures, promoted through direct install retrofit programs, and installed in commercial and industrial buildings (C&I).

Midstream measures include efficient lighting products including, but not limited to, efficient Light-Emitting Diode (LED) lamps and fixtures, promoted through point-of-sale (also referred to as midstream) distributors.

Baseline Efficiency:

For C&I lighting retrofit installations, the baseline efficiency case is project-specific and is determined using actual fixture counts and wattages from the existing space.

All midstream measures assume a blend of retrofit and lost opportunity baseline,[1] determined using assumed wattages for each of the replaced lamps or fixtures

High Efficiency:

For C&I lighting retrofit installations, the high efficiency case is project-specific and is determined using actual fixture counts and wattages for the project.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = \left(\sum_{i=1}^{n} ((Count_{\_i} * Watts_{\_i} / 1000)_{BASE}) - \sum_{j=1}^{n} (Count_{\_j} * Watts_{\_j} / 1000)_{EE}) \right) \times (Hours)$

$\Delta kW = \sum_{i=1}^{n} ((Count_{i} * Watts_{i} / 1000)_{BASE}) - \sum_{j=1}^{n} (Count_{j} * Watts_{j} / 1000)_{EE})$

Where:
n = Total number of fixture types in baseline or pre-retrofit case
m = Total number of installed fixture types
$Count_{\_i}$ = Quantity of existing fixtures of type i.
$Watts_{\_i}$ = Existing fixture or baseline wattage for fixture type i
$Count_{\_j}$ = Quantity of efficient fixtures of type j.
$Watts_{\_j}$ = Efficient fixture wattage for fixture type j.
1000 = Conversion factor: 1000 watts per kW.
Hours = Lighting annual hours of operation.

For retrofit installations, the annual hours of operation is project-specific and determined using actual building operation data in which the lighting equipment was installed. If site specific hours of operation are unavailable or if vendor estimates of building operating hours are unrealistically different from standard building type operating hours, then refer to the operating hours defined for midstream lighting, which is based on a program evaluation from CT.[1]

For Midstream:

$\Delta kWh = n * (DeltaWatts/1000) * Hours$

$\Delta kW = n * DeltaWatts /1000$

Where:
n = Total number of fixture or lamp types in project.
DeltaWatts = Calculated difference between efficient and baseline wattage (see table below)
1000 = Conversion factor: 1000 watts per kW.
Hours = Lighting annual hours of operation.

The following delta watt values are based on C&I Upstream Lighting, Mass Saves.[2]

Product	Product Type	delta Watts[2]
BR20/PAR20	Screw-In LEDs	28.1
BR20/PAR30	Screw-In LEDs	38.1
BR40/PAR38	Screw-In LEDs	44.2
MR16	Screw-In LEDs	22.1
A-line, 75/100w	Screw-In LEDs	30.5
Decoratives	Screw-In LEDs	13.6
LED Retrofit kit, <25W	Screw-In LEDs	38.4
LED Retrofit kit, >25W	Screw-In LEDs	49.60
Stairwell Kit, Low-Output w/sensor	LED Stairwell Kits	41.30
Stairwell Kit, Mid-Output w/sensor	LED Stairwell Kits	35.60
G24 LED	Screw-In LEDs	15.3
G23 LED	Screw-In LEDs	8.4
T8 TLED, 4ft	Linear LEDs	13.8
T8 TLED, 2ft	Linear LEDs	6.9
A-line, 40/60w	Screw-In LEDs	21.7
2x4 LED Fixture Standard	Linear LEDs	33.0
2x4 LED Fixture Premium	Linear LEDs	37.0
2x2 LED Fixture Standard	Linear LEDs	29.0
2x2 LED Fixture Premium	Linear LEDs	33.0
1x4 LED Fixture Standard	Linear LEDs	16.0
1x4 LED Fixture Premium	Linear LEDs	20.0
2x4 LED Fixture Standard w Controls	Linear LEDs w Controls	42.9
2x4 LED Fixture Premium w Controls	Linear LEDs w Controls	48.1
2x2 LED Fixture Standard w Controls	Linear LEDs w Controls	37.7

2x2 LED Fixture Premium w Controls	Linear LEDs w Controls	42.9
1x4 LED Fixture Standard w Controls	Linear LEDs w Controls	20.8
1x4 LED Fixture Premium w Controls	Linear LEDs w Controls	26.0
T5 LED	Linear LEDs	20.0
U-Bend LED	Linear LEDs	23.4
High/Low Bay 50-99W	High Bay/Low Bay	174.0
High/Low Bay 100-199W	High Bay/Low Bay	229.0
High/Low Bay >= 200W	High Bay/Low Bay	334.0
Exterior LED 20-99W	Exterior LEDs	101.5
Exterior LED 100-199W	Exterior LEDs	176.5
Exterior LED >= 200W	Exterior LEDs	231.5
1x4 LED Troffer Retrofit Kit - Premium	Linear LEDs	37.3
1x4 LED Troffer Retrofit Kit - Standard	Linear LEDs	29.5
2x2 LED Troffer Retrofit Kit - Premium	Linear LEDs	19.6
2x2 LED Troffer Retrofit Kit - Standard	Linear LEDs	18.1
2x4 LED Troffer Retrofit Kit - Premium	Linear LEDs	56.2
2x4 LED Troffer Retrofit Kit - Standard	Linear LEDs	53.5
LED Ambient/Strip/Wrap	Linear LEDs	21.8
Mogul High Bay	High Bay/Low Bay	283.6
Mogul Low Bay	High Bay/Low Bay	191.0
Mogul Ext 175W	Exterior LEDs	141.9
Mogul Ext 250W	Exterior LEDs	184.9
Mogul Ext 400W	Exterior LEDs	283.3
LED Tubes, 3ft Type A	Linear LEDs	12.0
LED Tubes, 8ft Type A	Linear LEDs	25.1
Parking Garage, 20-99W - Standard	Exterior LEDs	122.9
Parking Garage, 20-99W - Premium	Exterior LEDs	130.5
Parking Garage, 100-199W - Standard	Exterior LEDs	249.4
Parking Garage, 100-199W - Premium	Exterior LEDs	253.9
Parking Garage, >= 200W - Standard	Exterior LEDs	561.6
Parking Garage, >= 200W - Premium	Exterior LEDs	583.1
High/Low Bay LED, 20-99W w/controls	High Bay/Low Bay w Controls	189.5
High/Low Bay LED, 100-199W w/controls	High Bay/Low Bay w Controls	260.1
High/Low Bay LED, >= 200W w/controls	High Bay/Low Bay w Controls	388.4

Midstream lighting measures will calculate gross energy savings using annual hours of operation defined for the building type in which the lamp was installed. These categories and hours of use are defined in the table below.

Midstream Hours of Use by Building Type

The following hours of operation are based on a program evaluation from CT.[3] Parking garages are included as an additional building type category that has not yet been evaluated. A review of TRM best practices indicates 8760 hours of use for parking garages.

Building Type	Hours of Use
24x7 lighting	8,760
Automotive	4,056
Education	2,967
Grocery	5,468
Health Care	5,564
Hotel/Motel	3,064
Industrial	5,793
Large Office	4,098
Other	6,211*
Parking Lot/ Streetlights	6,887
Religious Building/ Convention Center	913
Restaurant	5,018
Retail	4,939
Small Office	3,748
Warehouse	5,667
Parking Garage	8,760

*Other includes recreational and entertainment facilities, service-oriented facilities, and other miscellaneous building types.

Measure Life:

The table below summarizes the adjusted measure lives (AML) for each measure. Note these AML values account for the estimated fraction of program lighting measures that are assumed to be lost opportunity (replace on failure) vs. retrofit (early replacement) based on MA evaluation research, as well as future year adjustments driven by expectations of high efficiency market adoption.

Measure Category	Measure	AML
Ambient Linear	TLED	10.53
Ambient Linear	LED Fixture	10.99
High/Low Bay	TLED	12.81
High/Low Bay	LED Fixture	12.84
High/Low Bay	LED Lamp	12.56
Exterior/Outdoor	TLED	10.12
Exterior/Outdoor	LED Fixture	10.18

Exterior/Outdoor	LED Lamp	9.74
Screw-Based	A-Line	4.69
Screw-Based	Downlight/Track	5.86
Screw-Based	Decorative	3.78

The table below summarizes the adjusted measure lives (AML) for each of the midstream measures. Note these AML values account for the estimated fraction of program lighting measures that are assumed to be lost opportunity (replace on failure) vs. retrofit (early replacement) based on MA evaluation research, as well as future year adjustments driven by expectations of high efficiency market adoption.[4]

BC Measure ID	Measure Category	Measure	Program	AML
E21C1c015 E21C2c015	Ambient Linear	TLED	LBES Midstream, SBES Midstream	10.53
E21C1c013 E21C2c013 E21C1c014 E21C2c014	Ambient Linear	LED Fixture	LBES Midstream, SBES Midstream	10.99
E21C1c012 E21C2c012	High/Low Bay	TLED	LBES Midstream, SBES Midstream	12.81
E21C1c012 E21C2c012	High/Low Bay	LED Fixture	LBES Midstream, SBES Midstream	12.84
E21C1c012 E21C2c012	High/Low Bay	LED Lamp	LBES Midstream, SBES Midstream	12.56
E21C1c011 E21C2c011	Exterior/Outdoor	TLED	LBES Midstream, SBES Midstream	10.12
E21C1c011 E21C2c011	Exterior/Outdoor	LED Fixture	LBES Midstream, SBES Midstream	10.18
E21C1c011 E21C2c011	Exterior/Outdoor	LED Lamp	LBES Midstream, SBES Midstream	9.74
E21C1c016 E21C2c016	Screw-Based	A-Line	LBES Midstream, SBES Midstream	4.69

E21C1c010 E21C2c010	Screw-Based	Downlight/Track	LBES Midstream, SBES Midstream	5.86
E21C1c016 E21C2c016	Screw-Based	Decorative	LBES Midstream, SBES Midstream	3.78

Other Resource Impacts:

Heating penalties for downstream, interior lighting systems (non-turnkey) are from a 12-month MA data logging study.[3] Penalties for interior turnkey are from the 2018 MA small business lighting impact evaluation.[4]

BC Measure ID	Measure Name	Program	MMBtu/kWh
E21C1a012 E21C1a013 E21C2a012 E21C2a013 E21C3a012 E21C3a013	Interior Lighting	LBES, SBES, MES	-0.000691
E21C1d014 E21C1d015 E21C2d014 E21C2d015 E21C3d014 E21C3d015	Interior Lighting (turnkey direct-install)	LBES, SBES, MES	-0.004080
E21C1a010 E21C1a011 E21C1d012 E21C1d013 E21C2a010 E21C2a011 E21C2d012 E21C2d013 E21C3a010 E21C3a011 E21C3d012 E21C3d013	Exterior Lighting	LBES, SBES, MES	n/a

Midstream: The following heating penalties are associated with lighting projects, determined from MA lighting evaluations.[5]

BC Measure ID	Measure Name	Program	MMBtu/kWh

E21C1c010 E21C2c010	LED Downlight	LBES Midstream, SBES Midstream	-0.000329
E21C1c011 E21C2c011	LED Exterior	LBES Midstream, SBES Midstream	N/A
E21C1c012 E21C2c012	LED High Bay/Low Bay	LBES Midstream, SBES Midstream	-0.000162
E21C1c013 E21C2c013	LED Linear Fixture	LBES Midstream, SBES Midstream	-0.000162
E21C1c014 E21C2c014	LED Linear Fixture with Controls	LBES Midstream, SBES Midstream	-0.000162
E21C1c015 E21C2c015	LED Linear Lamp	LBES Midstream, SBES Midstream	-0.000162
E21C1c016 E21C2c016	LED Screw In	LBES Midstream, SBES Midstream	-0.000329
E21C1c017 E21C2c017	LED Stairwell Kit	LBES Midstream, SBES Midstream	N/A

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a012 E21C1a013	Interior Lighting	LBES	1.000	0.999	1.000	1.000	0.504	0.389
E21C2a012 E21C2a013 E21C3a012 E21C3a013	Interior Lighting	SBES, MES	1.000	1.066	1.135	1.000	0.504	0.389
E21C1a010 E21C1a011	Exterior Lighting	LBES	1.000	0.999	1.000	1.000	0.000	1.000
E21C2a010 E21C2a011 E21C3a010 E21C3a011	Exterior Lighting	SBES, MES	1.000	1.027	1.000	1.000	0.000	1.000
E21C1d014 E21C1d015	Interior Lighting (turnkey direct-install)	LBES	1.000	0.999	1.000	1.000	0.504	0.389
E21C2d014 E21C2d015 E21C3d014 E21C3d015	Interior Lighting (turnkey direct-install)	SBES, MES	1.000	1.066	1.135	1.000	0.504	0.389

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1d012 E21C1d013	Exterior Lighting (turnkey direct-install)	LBES	1.000	0.999	1.000	1.000	0.000	1.000
E21C2d012 E21C2d013 E21C3d012 E21C3d013	Exterior Lighting (turnkey direct-install)	SBES, MES	1.000	1.027	1.000	1.000	0.000	1.000

Midstream:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c010 E21C2c010	LED Downlight	LBES Midstream, SBES Midstream	0.859	1.267	1.000	1.000	0.70	0.49
E21C1c011 E21C2c011	LED Exterior	LBES Midstream, SBES Midstream	0.955	0.989	1.000	1.000	0.00	1.00
E21C1c012 E21C2c012	LED High Bay/Low Bay	LBES Midstream, SBES Midstream	0.996	0.747	1.000	1.000	0.83	0.65
E21C1c013 E21C2c013	LED Linear Fixture	LBES Midstream, SBES Midstream	0.971	1.135	1.000	1.000	0.83	0.65
E21C1c014 E21C2c014	LED Linear Fixture with Controls	LBES Midstream, SBES Midstream	0.971	1.135	1.000	1.000	0.83	0.65
E21C1c015 E21C2c015	LED Linear Lamp	LBES Midstream, SBES Midstream	0.971	1.135	1.000	1.000	0.83	0.65
E21C1c016 E21C2c016	LED Screw In	LBES Midstream, SBES Midstream	0.714	1.712	1.000	1.000	0.70	0.49
E21C1c017 E21C2c017	LED Stairwell Kit	LBES Midstream, SBES Midstream	0.955	0.989	1.000	1.000	0.82	0.82

<u>In-Service Rates:</u>

All downstream installations have 100.0% in service rate since programs include verification of equipment installations.

Midstream in-service rates are based on the C1635 Impact Evaluation of PY 2016 and 2017 Energy Opportunities (EO) Program Report.[8]

<u>Realization Rates:</u>

Large Business Energy Solutions uses a 99.9% realization rate. Realization rates for Small Business Energy Solutions and Municipal Energy Solutions are based on NH evaluation results for municipal and small business facilities.[5] They account for operational hours of use adjustments, electric HVAC interactive adjustments for kWh and summer peak kW, and other adjustments. Exterior lighting realization rates account for the same adjustments except the HVAC interactive adjustment.

Midstream realization rates are based on the C1635 Impact Evaluation of PY 2016 and 2017 Energy Opportunities (EO) Program Report. [8] The HVAC interaction adjustment factor is determined from MA[8, 2] and CT[8] lighting project evaluations.

Coincidence Factors:

Summer and winter coincidence factors are based on NH evaluation results. [5, 6]
Midstream summer and winter coincidence factors are based on MA 2017 Upstream Lighting Impact evaluation.[9] LED screw-in coincident factors also applied to LED downlights.

Impact Factors for Calculating Net Savings:

Midstream and downstream free-ridership and spillover are based on study results from CT—which is the nearby jurisdiction with programs and markets most similar to those in NH.[10]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1c010 E21C2c010	LED Downlight	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c011 E21C2c011	LED Exterior	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c012 E21C2c012	LED High Bay/Low Bay	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c013 E21C2c013	LED Linear Fixture	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c014 E21C2c014	LED Linear Fixture with Controls	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c015 E21C2c015	LED Linear Lamp	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1c016 E21C2c016	LED Screw In	LBES Midstream, SBES Midstream	60%	23%	0%	63%
E21C1c017 E21C2c017	LED Stairwell Kit	LBES Midstream, SBES Midstream	34%	11%	0%	77%
E21C1a012 E21C1a013 E21C2a012 E21C2a013 E21C3a012 E21C3a013	Interior Lighting	LBES, SBES, MES	16%	5%	0%	89%

E21C1d014 E21C1d015 E21C2d014 E21C2d015 E21C3d014 E21C3d015	Interior Lighting (turnkey direct-install)	LBES, SBES, MES	16%	5%	0%	89%
E21C1a010 E21C1a011 E21C2a010 E21C2a011 E21C3a010 E21C3a011	Exterior Lighting	LBES, SBES, MES	16%	5%	0%	89%
E21C1d012 E21C1d013 E21C2d012 E21C2d013 E21C3d012 E21C3d013	Exterior Lighting (turnkey direct-install)	LBES, SBES, MES	16%	5%	0%	89%

Energy Load Shape:

Energy load shapes are based on site-level metering of project sites in MA.[7]

Measure Name	Summer On-peak	Winter On-peak	Summer Off-peak	Winter Off-peak
Interior Lighting	34.3%	30.3%	18.1%	17.4%
Exterior Lighting	19.2%	20.1%	29.0%	31.6%

Endnotes:
1: DNV GL, June 30, 2020. C1635 Impact Evaluation of PY 2016 & 2017 Energy Opportunities Program, Draft Report. Table 5-17. Interior Fixture Hours of Use Results by Building Type. Available at: https://www.energizect.com/connecticut-energy-efficiency-board/evaluation-reports
2: DNV GL, April 6, 2020. MA19C14-E-LGHTMKT: 2019 C&I Lighting Inventory and Market Model Updates. https://ma-eeac.org/wp-content/uploads/MA19C14-E-LGHTMKT_2019-CI-Lighting-Inventory-and-Market-Model-Report_Final_2020.04.06.pdf
3: DNV KEMA, June 21, 2013. Impact Evaluation of 2010 Prescriptive Lighting Installations. https://ma-eeac.org/wp-content/uploads/Impact-Evaluation-of-2010-Prescriptive-Lighting-Installations-Final-Report-6-21-13.pdf
4: DNV GL, ERS, June 7, 2018. Impact Evaluation of PY2016 Small Business Initiative: Phase I https://ma-eeac.org/wp-content/uploads/P69-Impact-Eval-of-MA-Small-Business-Initiative-Phase-I-Lighting_Report_FINAL.pdf
5: DNV GL, June 21, 2018. Impact Evaluation of 2016 New Hampshire Commercial & Industrial Small Business and Municipal Lighting. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/small-business-and-municipal-lighting-impact-evaluation.pdf

6: DNV GL, September 25, 2015. New Hampshire Utilities Large Commercial & Industrial (C&I) Retrofit and New Equipment & Construction Program Impact Evaluation. https://puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/New%20Hampshire%20Large%20C&I%20Program%20Impact%20Study%20Final%20Report.pdf
7: DNV GL, 2018. P72 Prescriptive C&I Loadshapes of Savings.
8: DNV GL, June 30, 2020, C1635 Impact Evaluation of PY 2016 and 2017 Energy Opportunities (EO) Program. Table 6-14: Upstream Lighting In-Service Rate Results and Table 6-19: Upstream Lighting kWh Realization Rate Recommendations Without In-Service Rates. Prepared for Connecticut Energy Efficiency Board (EEB). Available at: https://www.energizect.com/connecticut-energy-efficiency-board/evaluation-reports
9: DNV GL, November 22, 2017. Impact Evaluation of PY2015 Massachusetts Commercial and Industrial Upstream Lighting Initiative. https://ma-eeac.org/wp-content/uploads/Upstream-Lighting-Initiative-Impact-Evaluation-PY2015.pdf
10: EMI, September 25, 2019 . C1644 EO Net-to-Gross Study, Final Report. https://www.energizect.com/sites/default/files/C1644%20-%20EO%20NTG%20Final%20Report_9.25.19.pdf
Mistream NTG values are based on Recommendation 2 on p. ES-6 and p. 51. For midstream, screw in values are applied to screw in lights, and linear values are applied to all other light types, which is consistent with the application of screw in and linear NTG values in the MA TRM. Downstream NTG values are based on Energy Opportunities NTG Study Results for Lighting shown in Table ES-1-1 on p. ES-3.

Revision History

Revision Number	Date	Description
56	1/14/2022	Corrected the three typos resulting from a copy and paste error in the delta watt column of the upstream lighting delta watt value table. Updated line items are LED Retrofit kit, >25 KW, Stairwell kit, low-output w/ sensor and stairwell kit, mid-output w/sensor.

2.52 Lighting – New Construction and Major Renovation

Measure Code	TBD
Market	Commercial
Program Type	Lost opportunity
Category	Lighting

Description:

The implementation of various lighting design principles aimed at creating a quality and appropriate lighting experience while reducing unnecessary light usage. This is often done by a professional in a new construction or major renovation situation. Advanced lighting design uses techniques like maximizing task lighting and efficient fixtures to create a system of optimal energy efficiency and functionality.

Baseline Efficiency:

The Baseline Efficiency assumes compliance with lighting power density requirements as mandated by New Hampshire State Building Code, which currently reflects IECC 2015 with direct reference for compliance to ASHRAE Standard 90.1-2013. These standards specify the maximum lighting power densities (LPDs) by building type (building area method) and interior space type (space-by-space method). LPDs apply to all new construction and major renovation projects.

High Efficiency:

The high efficiency scenario assumes lighting systems that achieve lighting power densities below those required by New Hampshire State Building Code. Actual site lighting power densities should be determined on a case-by-case basis. Please refer to the current year application form for minimum percentage better than code efficiency requirements.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = \sum_{i=1}^{n}$ ((LPD_base_i - Controlled × LPD_proposed_i) × Area_i × Hours_i × 1/1000)

$\Delta kWFixture \sum_{i=1}^{n}$ ((LPD_base_i - LPD_proposed_i) × 1/1000 × Area_i × 1/1000)

$\Delta kWControlled = \sum_{i=1}^{n}$ (LPD_proposed_i × Area_i × 1/1000)

Where:

n = Total number of spaces, or 1 for Building Area Method
LPD_base_i = Baseline lighting power density for building or space type i (Watts/ft^2)
Area_i = Area of building or space i (ft^2)
Hours_i = Annual hours of operation of the lighting equipment for space type i
LPD_proposed_i = Proposed lighting power density for building or space type i (Watts/ft^2)
Controlled = Min % of controlled lighting above required amounts

1000 = Conversion factor: 1000 watts per 1 kW
Note on HVAC system interaction: Additional Electric savings from cooling system interaction are included in the calculation of adjusted gross savings for Lighting Systems projects. The HVAC interaction adjustment factor is determined from lighting project evaluations and is included in the energy realization rates and demand coincidence factors and realization rates.

Measure Life:

Measure lives are deemed based on study results from MA.[1]

BC Measure ID	Measure Name	Program	Measure Life
E21C1b013 E21C2b013 E21C3b013	Performance Lighting (Interior)	LBES, SBES, MES	15
E21C1b011 E21C2b011 E21C3b011	Performance Lighting (Exterior)	LBES, SBES, MES	15
E21C1b012 E21C2b012 E21C3b012	Performance Lighting w/ controls (Interior)	LBES, SBES, MES	15
E21C1b010 E21C2b010 E21C3b010	Performance Lighting w/ controls (Exterior)	LBES, SBES, MES	15

Other Resource Impacts:

Heating penalties are from alighting program evaluation performed on lighting systems in Massachusetts.[2]

BC Measure ID	Measure Name	Program	MMBtu/kWh
E21C1b012 E21C2b012 E21C3b012 E21C1b013 E21C2b013 E21C3b013	Performance lighting (interior) w/ and w/out controls	LBES, SBES, MES	-0.000162279
E21C1b010 E21C2b010 E21C3b010 E21C1b011 E21C2b011 E21C3b011	Performance lighting (exterior) w/ and w/out controls	LBES, SBES, MES	n/a

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1b012 E21C1b013	Performance lighting (interior)	LBES	1.000	0.999	1.000	1.000	1.000	0.504	0.389
E21C2b012 E21C3b012 E21C2b013 E21C3b013	Performance lighting (interior)	SBES, MES	1.000	1.066	1.000	1.135	1.000	0.504	0.389
E21C1b010 E21C1b011	Performance lighting (exterior)	LBES	1.000	0.999	1.000	1.000	1.000	0.000	1.000
E21C2b010 E21C3b010 E21C2b011 E21C3b011	Performance lighting (exterior)	SBES, MES	1.000	1.027	1.000	1.000	1.000	0.000	1.000

In-Service Rates:

All installations have a 100.0% in service rate unless an evaluation finds otherwise.

Realization Rates:

Large Business Energy Solutions uses a 99.9% realization rate. Energy and demand realization rates for Small Business Energy Solutions and Municipal Energy Solutions are based on a NH study of municipal and small business customers.[3] Realization rates for summer peak demand savings in interior systems reflect a 113.5% HVAC interactive multiplier.

Coincidence Factors:

All coincidence factors are based on a NH study of municipal and small business customers.[3]

Impact Factors for Calculating Net Savings[5]:

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	NTG
E21C1b013 E21C2b013 E21C3b013	Performance Lighting (Interior)	LBES, SBES, MES	16%	5%	0%	89%
E21C1b011 E21C2b011 E21C3b011	Performance Lighting (Exterior)	LBES, SBES, MES	16%	5%	0%	89%
E21C1b012 E21C2b012 E21C3b012	Performance Lighting w/ controls (Interior)	LBES, SBES, MES	16%	5%	0%	89%
E21C1b010 E21C2b010 E21C3b010	Performance Lighting w/ controls (Exterior)	LBES, SBES, MES	16%	5%	0%	89%

Energy Load Shape:

Energy load shapes are based the MA P72 C&I loadshape study.[4]

Measure Name	Summer On-peak	Winter On-peak	Summer Off-peak	Winter Off-peak
Interior Lighting	34.3%	30.3%	18.1%	17.4%
Exterior Lighting	19.2%	20.1%	29.0%	31.6%

Endnotes:
1: DNV GL, ERS, July 22, 2019. Lighting Outyear Factor and Equivalent Measure Life. https://ma-eeac.org/wp-content/uploads/Lighting-Outyear-Factor-and-Equivalent-Measure-Life-Update_Final.pdf
2: DNV GL, ERS, NMR, November 22, 2017. Impact Evaluation of PY2015 Massachusetts Commercial and Industrial Upstream Lighting Initiative https://ma-eeac.org/wp-content/uploads/Upstream-Lighting-Initiative-Impact-Evaluation-PY2015.pdf
3: DNV GL, June 21, 2018. Impact Evaluation of 2016 New Hampshire Commercial & Industrial Small Business and Municipal Lighting https://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/small-business-and-municipal-lighting-impact-evaluation.pdf
4: DNV GL, 2018. P72 Prescriptive C&I Loadshapes of Savings
5: DNV GL June 30, 2020. C1635 Impact Evaluation of PY 2016 & 2017 Energy Opportunities Program, Table 5-20. (CT). Available at: https://www.energizect.com/connecticut-energy-efficiency-board/evaluation-reports
5: EMI, September 25, 2019 . C1644 EO Net-to-Gross Study, Final Report. https://www.energizect.com/sites/default/files/C1644%20-%20EO%20NTG%20Final%20Report_9.25.19.pdf
Downstream NTG values are based on Energy Opportunities NTG Study Results for Lighting shown in Table ES-1-1 on p. ES-3.

2.53 Motors & Drives - Variable Frequency Drive

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit/Lost Opportunity
Category	Motors and Drives

Description:

This measure covers the installation of variable speed drives according to the terms and conditions stated on the state-wide worksheet. The measure covers multiple end use types and building types. The installation of this measure saves energy since the power required to rotate a pump or fan at lower speeds requires less power than when rotated at full speed.

Baseline Efficiency:

The baseline efficiency case measure varies with equipment type. All baselines assume either a constant or 2-speed motor. Air or water volume/temperature is controlled using valves, dampers, and/or reheats. If the project includes a motor replacement, additional savings may result from improved motor efficiency. Motors controlled by VFDs need to be "inverter rated" or may fail prematurely, thus requiring a simultaneous VFD addition and motor replacement project.

High Efficiency:

In the high efficiency case, pump flow or fan air volume is directly controlled by the VFD based on input from the system or process controller. The pump or fan will automatically adjust its speed based on inputted set points, control strategies and the downstream feedback it receives from the system or process controller.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = HP \times \frac{kWh}{HP}$$

$$\Delta kW_{SP} = HP \times \frac{kW_{SP}}{HP}$$

$$\Delta kW_{WP} = HP \times \frac{kW_{WP}}{HP}$$

Where:

HP = Rated horsepower for the impacted motor

$\frac{kWh}{HP}$ = Annual electric energy reduction based on building and equipment type. See table below.

$\frac{kW_{SP}}{HP}$ = Summer demand reduction based on building and equipment type. See table below.

$\frac{kW_{WP}}{HP}$ = Winter demand reduction based on building and equipment type. See table below.

Savings factors below already account for motor efficiency and consequently an adjustment is not required in the algorithm.

Savings Factors for C&I VFDs without Motor Replacement (kWh/HP [1] and kW/HP) [2]

Building Type[3]	Building Exhaust Fan	Cooling Tower Fan	Chilled Water Pump	Boiler Feed Water Pump	Hot Water Circulating Pump	MAF - Make-up Air Fan	Return Fan	Supply Fan	WS Heat Pump
Corresponding Fan or Pump Application Codes: [6]	PEF	CTF CWP PCP HYP RAS WTP	CHWP	FWP	HWP	MAF	RFA	SFA BEF HEF RFP SFP	WHP
Annual Energy Savings Factors (kWh/HP)									
University/College	3641	449	745	2316	2344	3220	1067	1023	3061
Elem/High School	3563	365	628	1933	1957	3402	879	840	2561
Multi-Family	3202	889	1374	2340	2400	3082	1374	1319	3713
Hotel/Motel	3151	809	1239	2195	2239	3368	1334	1290	3433
Health	3375	1705	2427	2349	2406	3002	1577	1487	3670
Warehouse	3310	455	816	2002	2087	3229	1253	1205	2818
Restaurant	3440	993	1566	1977	2047	2628	1425	1363	3542
Retail	3092	633	1049	1949	2000	2392	1206	1146	2998
Grocery	3126	918	1632	1653	1681	2230	1408	1297	3285
Offices	3332	950	1370	1866	1896	3346	1135	1076	3235
Summer Demand Savings Factors (kW/HP_{SP})									
University/College	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Elem/High School	0.377	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Multi-Family	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Hotel/Motel	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Health	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Warehouse	0.109	-0.023	0.174	0.457	0.091	0.261	0.287	0.274	0.218

Restaurant	0.261	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Retail	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Grocery	0.261	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Offices	0.109	-0.023	0.174	0.457	0.091	0.109	0.287	0.274	0.218
Winter Demand Savings Factors (kW/HP_{WP})									
University/College	0.377	-0.006	0.184	0.457	0.21	0.109	0.26	0.252	0.282
Elem/High School	0.457	-0.006	0.184	0.457	0.21	0.109	0.26	0.252	0.282
Multi-Family	0.109	-0.006	0.184	0.355	0.21	0.109	0.26	0.252	0.282
Hotel/Motel	0.109	-0.006	0.184	0.418	0.21	0.109	0.26	0.252	0.282
Health	0.377	-0.006	0.184	0.275	0.21	0.109	0.26	0.252	0.282
Warehouse	0.377	-0.006	0.184	0.178	0.21	0.261	0.26	0.252	0.282
Restaurant	0.109	-0.006	0.184	0.355	0.21	0.109	0.26	0.252	0.282
Retail	0.109	-0.006	0.184	0.275	0.21	0.109	0.26	0.252	0.282
Grocery	0.457	-0.006	0.184	0.418	0.21	0.109	0.26	0.252	0.282
Offices	0.457	-0.006	0.184	0.418	0.21	0.109	0.26	0.252	0.282

Savings Factors for C&I VFDs with Motor Replacement (kWh/HP [1] and kW/HP [2]) :

Building Type[3]	**Building Exhaust Fan**	**Cooling Tower Fan**	**Chilled Water Pump**	**Boiler Feed Water Pump**	**Hot Water Circulating Pump**	**MAF - Make-up Air Fan**	**Return Fan**	**Supply Fan**
Corresponding Fan or Pump Application Codes:[6]	PEF	CTF CWP PCP HYP RAS WTP	CHWP	FWP	HWP	MAF	RFA	SFA BEF HEF RFP SFP
Annual Energy Savings Factors (kWh/HP)								
University/College	3,802	486	780	2,415	2,442	3,381	1,143	1,100
Elem/High School	3,721	396	657	2,015	2,040	3,561	941	903
Multi-Family	3,368	954	1,435	2,443	2,504	3,248	1,466	1,412
Hotel/Motel	3,317	866	1,294	2,291	2,335	3,534	1,425	1,381
Health	3,541	1,815	2,535	2,453	2,510	3,168	1,676	1,586
Warehouse	3,476	496	853	2,098	2,183	3,396	1,342	1,294
Restaurant	3,606	1,066	1,636	2,067	2,138	2,794	1,519	1,457
Retail	3,258	685	1,097	2,036	2,087	2,558	1,288	1,229
Grocery	3,292	1,001	1,710	1,724	1,753	2,396	1,498	1,386
Offices	3,498	1,014	1,432	1,947	1,977	3,512	1,210	1,151
Summer Demand Savings Factors (kW/HP_{SP})								
University/College	0.257	(0.004)	0.465	0.952	0.190	0.257	0.679	0.706

Elem/High School	1.187	(0.006)	0.697	1.428	0.286	0.385	1.019	1.058
Multi-Family	0.385	(0.006)	0.697	1.428	0.286	0.385	1.019	1.058
Hotel/Motel	0.257	(0.004)	0.465	0.952	0.190	0.257	0.679	0.706
Health	0.128	(0.002)	0.232	0.476	0.095	0.128	0.340	0.353
Warehouse	0.770	(0.012)	1.394	2.855	0.571	1.677	2.038	2.117
Restaurant	0.839	(0.006)	0.697	1.428	0.286	0.385	1.019	1.058
Retail	0.514	(0.008)	0.930	1.904	0.381	0.514	1.358	1.411
Grocery	0.280	(0.002)	0.232	0.476	0.095	0.128	0.340	0.353
Offices	0.257	(0.004)	0.465	0.952	0.190	0.257	0.679	0.706
Winter Demand Savings Factors (kW/HP$_{WP}$)								
University/College	0.791	(0.001)	0.384	0.952	0.437	0.257	0.563	0.544
Elem/High School	1.428	(0.002)	0.575	1.428	0.655	0.385	0.844	0.816
Multi-Family	0.385	(0.002)	0.575	1.123	0.661	0.385	0.844	0.816
Hotel/Motel	0.257	(0.001)	0.384	0.874	0.438	0.257	0.563	0.544
Health	0.396	(0.001)	0.192	0.294	0.223	0.128	0.281	0.272
Warehouse	2.374	(0.003)	1.151	1.181	1.384	1.677	1.688	1.632
Restaurant	0.385	(0.002)	0.575	1.123	0.661	0.385	0.844	0.816
Retail	0.514	(0.002)	0.767	1.178	0.893	0.514	1.125	1.088
Grocery	0.476	(0.001)	0.192	0.437	0.219	0.128	0.281	0.272
Offices	0.952	(0.001)	0.384	0.874	0.438	0.257	0.563	0.544

Measure Life:

The measure life for lost opportunity is 15 years. For retrofit, this measure was determined to be an add on, single baseline measure, so it will leverage the same 15 year life as lost opportunity. [4]

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a043 E21C1d043 E21C2a043 E21C2d043 E21C3a087 E21C3d087	Variable Frequency Drive	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	1.00	0.946	n/a	1.265	1.415	1.00	1.00
E21C1a044 E21C1d044 E21C2a044 E21C2d044 E21C3a088 E21C3d088	Variable Frequency Drive with Motor	LBES Retro LBES DI SBES Retro SBES DI Muni Retro Muni DI	1.00	0.946	n/a	1.265	1.415	1.00	1.00

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

Realization rates are based on study results.[5]

<u>Coincidence Factors:</u>

CFs for all programs set to 100% since summer and winter demand savings are based on evaluation results.

Energy Load Shape:

See Appendix 1 C&I Load Shape "C&I VFD (Combined)".

<u>Endnotes</u>:

1: Chan, Tumin, 2010. Formulation of a Prescriptive Incentive for the VFD and Motors & VFD impact tables at NSTAR.

2: For Chilled Water Pump, Hot Water Circ. Pump, Return Fan, Supply Fan, and WSHP Circ. Loop: kW/HP estimates derived from Cadmus, 2012. Variable Speed Drive Loadshape Project. Prepared for the NEEP Regional Evaluation, Measurement & Verification Forum. Other drive type kW/HP savings estimates based on Chan, Tumin (2010). Formulation of a Prescriptive Incentive for the VFD and Motors & VFD impact tables at NSTAR. Prepared for NSTAR.

3: Building types listed in the project information map to the building types listed in the TRM as follows:

TRM	Project Info Bldg Type Matched to TRM Bldg Types for VFD Calc
Elm/H School	Daycare

	Education - K-12 School
Grocery	Grocery
Health	Exercise center
	Gymnasium
	Health/Medical - Clinic
	Hospital
	Sports arena
Hotel/Motel	Hotel/Motel/Lodging
	Penitentiary
Multi-Family	Multifamily
	Nursing Home
Offices	Convention center
	Courthouse
	Library
	Office - Medium/Large (> 20,000 ft²)
	Office - Small (< 20,000 ft²)
	Police station
	Religious Worship/Church
	Town hall
Restaurant	Dining: bar/lounge/leisure
	Dining: Cafeteria/Fast Food
	Dining: Family
Retail	Motion picture theater
	Museum
	Performing arts theater
	Post office
	Retail
University/College	Dormitory
	Education - College/University
	Education - Community College
Warehouse	Automotive facility
	Fire station
	Industrial/Manufacturing - 1 Shift
	Industrial/Manufacturing - 2 Shifts
	Industrial/Manufacturing - 3 Shifts
	Parking garage
	Storage Facility
	Transportation
	Warehouse - Distribution Center
	Warehouse - Inactive Storage

	Workshop

4: Energy & Resource Solutions, November (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities.https://www.ers-inc.com/wp-content/uploads/2018/04/Measure-Life-Study_MA-Joint-Utilities_ERS.pdf, Baseline Categories and preliminary Out Year Factors are described at a high level in DNV GL, ERS (2018). Portfolio Model Companion Sheet. Additional background on the baseline categorization given in DNV GL, ERS (2018). Portfolio Model Methods and Assumptions – Electric and Natural Gas Memo

5: DNV GL (2020). Impact Evaluation of PY 2017 Small Business Initiative Non-Lighting Measures.
6: The corresponding measure names for the application codes are:

Code	Application
BDF	Boiler Draft Fan
CHWP	Chilled Water Pump
CTF	Cooling Tower Fan
CWP	Condenser Water Pump
FWP	Boiler Feed Water Pump
HWP	Hot Water Circulator Pump
MAF	Make-up Air Fan (CHW Cooling Only)
PCP	Process Cooling Pump
PE	Process Exhaust and Make-up Fan
RFA	HVAC Return Air Fan (CHW Cooling Only)
SFA	HVAC Supply Air Fan (CHW Cooling Only)
WHP	WS Heat Pump Loop Circulator Pump
BEF	BEF - Building Exhaust Fan
HEF	HEF - Fume Hood Exhaust & Makeup Air Fan
HP	HYP - Hydraulic Pump
RAS	RAS - RAS Pump in Wastewater Treatment Plant
RFP	RFP - Return Fan on VAV Packaged HVAC Unit
WFP	SFP - Supply Fan on VAV Packaged HVAC Unit
WTP	WTP - Water Supply or Wastewater Treatment Pump

Revision History

Revision Number	Date	Description
57	1/14/2022	Changed the formatting of the algorithm for caculating energy impact for clarity.
71	3/1/2022	Included explanation of how project information verbiage and VFD application codes map to the savings values in the TRM.

2.54 Refrigeration - Case Motor Replacement

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Replacement of shaded-pole (SP) or permanently-split capacitor (PSC) motors with electronically commutated motors (ECMs) in the evaporators for multi-deck and freestanding coolers and freezers, typically on the retail floor of convenience stores, liquor stores, and grocery stores.[1]

Baseline Efficiency:

The baseline efficiency case is the existing case motor, either SP or PSC type.

High Efficiency:

The high efficiency case is the replacement of the existing case motor with an ECM.

Algorithms for Calculating Primary Energy Impact:

$\Delta kWh = \Delta kWh_{Motor} + \Delta kWh_{Heat}$
$\Delta kWh_{Motor} = kW_{Motor} \times LRF \times Hours$
$\Delta kWh_{Heat} = \Delta kWh_{Motor} \times 0.28 \times Eff_{RS}$
$\Delta kW = \frac{\Delta kWh}{8{,}760}$
Where:
ΔkWh_{Motor} = Energy savings due to increased efficiency of case motor
ΔkWh_{Heat} = Energy savings due to reduced heat from evaporator fans
kW_{Motor} = Rated input power of the existing case motor
LRF = Load reduction factor: 53% when SP motors are replaced, 29% when PSC motors are replaced[2].
.$Hours$ = Average runtime of case motors (8,500 hours)[3]
0.28 = Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS} = Efficiency of typical refrigeration system (1.6 kW/ton) [4]
ΔkW = Average demand savings
8,760 = Hours per year

Measure Life:

The measure life is 15 years[5]. This measure is determined to have an add-on single baseline in retrofit scenarios.

This measure is determined to have an add-on single baseline in retrofit scenarios.

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a016	Case Motor Replacement	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C1d018	Case Motor Replacement	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C2a016	Case Motor Replacement	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C2d018	Case Motor Replacement	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3a016	Case Motor Replacement	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3d018	Case Motor Replacement	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

All programs use a coincidence factor of 100% since demand savings are average and expected to be consistent.

Energy Load Shape:

See Appendix 1 C&I Load Shapes “C&I Refrigeration”.

Endnotes:
1: The assumptions and algorithms used in this section are specific to NRM products.
2: Load factor is an estimate by NRM based on several pre- and post-meter readings of installations
3: Conservative value based on 15 years of NRM field observations and experience.
4: Select Energy (2004). Cooler Control Measure Impact Spreadsheet Users’ Manual. Prepared for NSTAR.

5: Energy & Resource Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities; 15-year measure life for retrofit motor installations.

2.55 Refrigeration – Door Heater Controls

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of controls to reduce the run time of door and frame heaters for freezers and walk-in or reach-in coolers. The reduced heating results in a reduced cooling load.

Baseline Efficiency:

The baseline efficiency case is a cooler or freezer door heater that operates 8,760 hours per year without any controls.

High Efficiency:

The high efficiency case is a cooler or freezer door heater connected to a heater control system, which controls the door heaters by measuring the ambient humidity and temperature of the store, calculating the dew point, and using pulse width modulation (PWM) to control the anti-sweat heater based on specific algorithms for freezer and cooler doors. Door temperature is typically maintained about 5°F above the store air dew point temperature.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kW = \frac{\mathrm{V} \times \mathrm{A}}{1{,}000} \times \%Off$$
$$\Delta kWh = \Delta kW \times 8{,}760$$

Where:
V = Nameplate heater voltage
A = Nameplate heater amperage
$\%Off$ = Controlled door heater off time: 46% for freezers and 74% for coolers[1]
8,760 = Hours per year

Measure Life:

The measure life is 10 years[2].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a019	Door Heater Controls	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	0.50	1.00
E21C1d021	Door Heater Controls	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	0.50	1.00
E21C2a019	Door Heater Controls	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	0.50	1.00
E21C2d021	Door Heater Controls	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	0.50	1.00
E21C3a025	Door Heater Controls	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	0.50	1.00
E21C3d027	Door Heater Controls	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	0.50	1.00

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

The CF values are based on MA TRM[3] until NH-specific evaluations are available.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Refrigeration".

Endnotes:
1:The value is an estimate by NRM based on hundreds of downloads of hours of use data from Door Heater controllers. These values are also supported by Select Energy Services, Inc. (2004). Cooler Control Measure Impact Spreadsheet User's Manual. Prepared for NSTAR. .
2: Energy & Resource Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities; Table 1-1
3: MA TRM (2020). 2019 Pan-Year Report Version. 3.82. Refrigeration – Door Heater Controls

2.56 Refrigeration – Electronic Defrost Control

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Install a controller to activate evaporator defrost only when necessary in a refrigeration system.

Baseline Efficiency:

The baseline efficiency case is an evaporator electric defrost system that uses a time clock to initiate defrost.

High Efficiency:

The high efficiency case is an evaporator electric defrost system with defrost controls based on refrigeration system runtime or load conditions.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = \Delta kWh_{Defrost} + \Delta kWh_{Heat}$$
$$\Delta kWh_{Defrost} = kW_{Defrost} \times Hr/Day \times 365 \times DRF$$
$$\Delta kWh_{Heat} = \Delta kWh_{Defrost} \times 0.28 \times Eff_{RS}$$
$$\Delta kW = \frac{\Delta kWh}{8{,}760}$$

Where:
$\Delta kWh_{Defrost}$ = Energy savings due to reduced runtime of defrost heaters
ΔkWh_{Heat} = Energy savings due to reduced heat from the defrost heaters
$kW_{Defrost}$ = Rated input power of the defrost heater
Hr/Day = Existing scheduled defrost hours per day
DRF = Defrost reduction factor – annual average of 35%[1]
365 = Days per year
0.28 = Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS} = Efficiency of typical refrigeration system (1.6 kW/ton) [2]
ΔkW = Average demand savings
8,760 = Hours per year

Measure Life:

The measure life is 10 years[3].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a024	Electronic Defrost Control	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C1d026	Electronic Defrost Control	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C2a024	Electronic Defrost Control	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C2d026	Electronic Defrost Control	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3a037	Electronic Defrost Control	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3d039	Electronic Defrost Control	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

All programs set coincident factors to 100% since demand savings are average and expected to be consistent.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Refrigeration".

Endnotes:
1: Supported by 3rd party evaluation: Independent Testing was performed by Intertek Testing Service on a Walk-in Freezer that was retrofitted with Smart Electric Defrost capability.
2: Assumed average refrigeration efficiency for typical installations. Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). Cooler Control Measure Impact Spreadsheet Users' Manual. Prepared for NSTAR.
3: Energy & Resource Solutions (2005). Measure Life Study – refrigeration controls for large C&I retrofit. Prepared for The Massachusetts Joint Utilities.

2.57 Refrigeration – Evaporator Fan Control

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of controls to modulate the evaporator fans based on the temperature in a refrigerated space.

Baseline Efficiency:

The baseline efficiency case is an evaporator fan which runs for 8,760 annual hours.

High Efficiency:

The high efficiency case is an evaporator fan with controls to reduce the fan speed or cycle the fan off when the refrigerated space temperature setpoint is met.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = \Delta kWh_{Fan} + \Delta kWh_{Heat} + \Delta kWh_{Control}$$

$$kW_{Fan} = \frac{V \times A \times PF \times \sqrt{Phase}}{1{,}000}$$

$$\Delta kWh_{Fan} = kW_{Fan} \times \%Off \times 8760$$

$$\Delta kWh_{Heat} = \Delta kWh_{Fan} \times 0.28 \times Eff_{RS}$$

$$\Delta kWh_{Control} = [\mathrm{kW_{CP}} \times Hours_{CP} + kW_{Fan} \times (1 - \%Off) \times 8760] \times 5\%$$

$$\Delta kW = \frac{\Delta kWh}{8760}$$

Where:
ΔkWh_{Fan} = Energy savings due to reduced runtime of evaporator fans
ΔkWh_{Heat} = Energy savings due to reduced heat from the defrost heaters
$\Delta kWh_{Control}$ = Energy savings due to optimized controls, estimated at 5% of compressor and fan energy by consensus estimates used in MA TRM
V = Rated fan motor voltage
A = Rated fan motor amperage per, phase-to-ground
PF = Typical evaporator fan motor power factor, 0.55[1]
$Phase$ = Phase of electric power supplying the evaporator motor
$\%Off$ = Reduction in annual evaporator fan run hours, 46%[2].
8760 = Hours per year
kW_{CP} = Nameplate input kW of the compressor
$Hours_{CP}$ = Equivalent full load hours of compressor operations: 4,072 hours[3]
0.28 = Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS} = Efficiency of typical refrigeration system (1.6 kW/ton) [3]

ΔkW = Average demand savings
8,760 = Hours per year

Measure Life:

The measure life is 10 years[4].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a027	Evaporator Fan Control	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C1d029	Evaporator Fan Control	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C2a027	Evaporator Fan Control	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C2d029	Evaporator Fan Control	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3a043	Evaporator Fan Control	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3d045	Evaporator Fan Control	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00

<u>In-Service Rates:</u>

All installations have a 100% in service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

All programs use CF values of 100% since demand savings are average and expected to be consistent.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Refrigeration".

Endnotes:
1: Conservative value based on 15 years of NRM field observations and experience.

2: The value is an estimate by NRM based on hundreds of downloads of hours of use data. These values are also supported by Select Energy Services, Inc. (2004). Cooler Control Measure Impact Spreadsheet User's Manual. Prepared for NSTAR
3: Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). Cooler Control Measure Impact Spreadsheet Users' Manual. Prepared for NSTAR.
4: Energy & Resource Solutions (2005). Measure Life Study – fan control retrofit. Prepared for The Massachusetts Joint Utilities.

2.58 Refrigeration – Novelty Cooler Shutoff

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of controls to shut off a facility's novelty coolers for non-perishable goods based on pre-programmed store hours.

Baseline Efficiency:

The baseline efficiency case a novelty cooler energized for 8,760 annual hours.

High Efficiency:

The high efficiency case is a novelty cooler whose energized hours follow the store's occupied hours, and is de-energized during unoccupied hours.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = kW_{NC} \times \mathrm{DC}_{\mathrm{AVG}} \times (Hours_{UNOCC} - 1) \times 365$$
$$\Delta kW = 0$$

Where:
kW_{NC} = Rated nameplate input power to the novelty cooler
$\mathrm{DC}_{\mathrm{AVG}}$ = Weighted average annual duty cycle: 49%[1]
$Hours_{UNOCC}$ = Daily unoccupied hours of the store
365 = Days per year

Measure Life:

The measure life is 10 years[2].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a037	Novelty Cooler Shutoff	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	0.00	0.00
E21C1d037	Novelty Cooler Shutoff	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	0.00	0.00
E21C2a037	Novelty Cooler Shutoff	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C2d037	Novelty Cooler Shutoff	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C3a066	Novelty Cooler Shutoff	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C3d066	Novelty Cooler Shutoff	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	0.00	0.00

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

Coincidence factors are zero since all energy savings occur during off-peak hours.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Refrigeration".

Endnotes:

1: Estimated value from NRM experience, supported by Select Energy Services, Inc. (2004). Cooler Control Measure Impact Spreadsheet Users' Manual. Prepared for NSTAR. The study gives a less conservative value than used by NRM.

2: Energy & Resource Solutions (2005). Measure Life Study – cooler shutoff retrofit. Prepared for The Massachusetts Joint Utilities.

2.59 Refrigeration – Vending Miser

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of controls intended to reduce the energy consumption of vending machine lighting and refrigeration systems. Qualifying controls must power down these systems during periods of inactivity but, in the case of refrigerated machines, must always maintain a cool product that meets customer expectations. This measure applies to refrigerated beverage vending machines, non-refrigerated snack vending machines, and glass front refrigerated coolers. This measure should not be applied to ENERGY STAR® qualified vending machines, as they already have built-in controls.

Baseline Efficiency:

The baseline efficiency case is a standard efficiency refrigerated beverage vending machine, nonrefrigerated snack vending machine, or glass front refrigerated cooler without a control system capable of powering down lighting and refrigeration systems during periods of inactivity.

High Efficiency:

The high efficiency case is a standard efficiency refrigerated beverage vending machine, non-refrigerated snack vending machine, or glass front refrigerated cooler with a control system capable of powering down lighting and refrigeration systems during periods of inactivity.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = kW_{rated} \times Hours \times SAVE$$

$$\Delta kW = \frac{\Delta kWh}{Hours}$$

Where:
kW_{rated} = Rated kW of connected equipment; if not available, use default values in table below
$Hours$ = Annual operating hours of connected equipment; if not available, use default value of 8,760
$SAVE$ = Percent savings factor, see table below for values

Vending Machine and Cooler Controls Savings Factors [1]

Equipment Type	kW rated	SAVE
Refrigerated Beverage Vending Machines	0.40	46%
Non-Refrigerated Snack Vending Machines	0.085	25%
Glass Front Refrigerated Coolers	0.46	35%

Measure Life:

The measure life is 5 years[2].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a045	Vending Miser	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	0.00	0.00
E21C1d045	Vending Miser	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	0.00	0.00
E21C2a045	Vending Miser	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C2d045	Vending Miser	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C3a089	Vending Miser	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	0.00	0.00
E21C3d089	Vending Miser	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	0.00	0.00

<u>In-Service Rates:</u>

All installations have a 100% in service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

Coincidence factors are 0.00 since energy savings occur during off-peak hours (hours of vending machine inactivity).

Energy Load Shape:

See Appendix 1 C&I Load Shapes " C&I Refrigeration".

Endnotes:

1: USA Technologies Energy Management Product Sheets (2006). USA_Tech_2006_Energy_Management_Product_Sheets

2: Energy & Resource Solutions (2005). Measure Life Study – vending control retrofit. Prepared for The Massachusetts Joint Utilities.

2.60 Refrigeration – ECM Evaporator Fan Motors for Walk-in Coolers and Freezers

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Retrofit
Category	Refrigeration

Description:

Installation of various sizes of electronically commutated motors (ECMs) in walk-in coolers and freezers to replace existing evaporator fan motors.

Baseline Efficiency:

The baseline efficiency case is an existing evaporator fan motor which is not ECM.

High Efficiency:

The high efficiency case is the replacement of existing evaporator fan motors with ECMs.

Algorithms for Calculating Primary Energy Impact:

$$\Delta kWh = \Delta kWh_{Motor} + \Delta kWh_{Heat}$$

$$\Delta kWh_{Motor} = \frac{V \times A \times PF \times \sqrt{Phase}}{1{,}000} \times LRF \times Hours$$

$$\Delta kWh_{Heat} = \Delta kWh_{Motor} \times 0.28 \times Eff_{RS}$$

$$\Delta kW = \frac{\Delta kWh}{8{,}760}$$

Where:
ΔkWh_{Motor} = Energy savings due to increased efficiency of evaporator motor
ΔkWh_{Heat} = Energy savings due to reduced heat from evaporator fans
V = Rated fan motor voltage
A = Rated fan motor amperage per, phase-to-ground
PF = Typical existing fan motor power factor, 0.55[1]
$Phase$ = Phase of electric power supplying the evaporator motor
LRF = Load reduction factor of 65%[2].
$Hours$ = Annual fan operating hours
0.28 = Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS} = Efficiency of typical refrigeration system (1.6 kW/ton) [1]
ΔkW = Average demand savings
8,760 = Hours per year

Measure Life:

The measure life is 15 years[3].

Other Resource Impacts:

There are no other resource impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Fuel	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1a023	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	LBES - Retrofit	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C1d025	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	LBES – Direct Install	1.00	0.999	n/a	1.00	1.00	1.00	1.00
E21C2a023	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	SBES - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C2d025	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	SBES – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3a036	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	Muni - Retrofit	1.00	1.00	n/a	1.00	1.00	1.00	1.00
E21C3d038	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	Electric	Muni – Direct Install	1.00	1.00	n/a	1.00	1.00	1.00	1.00

In-Service Rates:

All installations have a 100% in service rate unless an evaluation finds otherwise.

Realization Rates:

All programs use a 100% realization rate unless an evaluation finds otherwise.

Coincidence Factors:

All programs set coincident factors to 100% since demand savings are average and expected to be consistent.

Energy Load Shape:

See Appendix 1 C&I Load Shapes "C&I Refrigeration".

Endnotes:
1: Conservative value based on 15 years of NRM field observations and experience.
2: Load factor is an estimate by NRM based on several pre- and post-meter readings of installations; the value is supported by RLW Analytics (2007). Small Business Services Custom Measure Impact Evaluation. Prepared for National Grid.
3: Energy & Resource Solutions (2005). Measure Life Study. Prepared for The Massachusetts Joint Utilities; 15-year measure life for retrofit motor installations.

2.61 Midstream Hot Water – Water Heaters

Measure Code	[To Be Defined in ANB system]
Market	Commercial
Program Type	Lost Opportunity
Category	**Hot Water**

Description:

- Midstream Heat Pump Water Heater 120 gallons
- Midstream Heat Pump Water Heater 80 gallons.
- Midstream Heat Pump Water Heater 50 gallons.
- Midstream Indirect Water Heater, Gas: Indirect water heaters use a storage tank that is heated by the main boiler. The energy stored by the water tank allows the boiler to turn off and on less often, saving considerable energy.
- Midstream On Demand Tankless Water Heater, Gas: Tankless water heaters circulate water through a heat exchanger to be heated for immediate use, eliminating the standby heat loss associated with a storage tank.
- Midstream Volume Water Heater, Gas: Installation of a high-efficiency gas-fired water heater.
- Midstream Condensing Water Heater, Gas: Installation of a high efficiency condensing gas water heater
-

Baseline Efficiency:

All Water Heaters: The baseline efficiency case assumes compliance with the efficiency requirements as mandated by New Hamsphire State Building Code. As described in the MA State Building Code, energy efficiency must be met via compliance with the relevant International Energy Conservation Code (IECC).

- Midstream Heat Pump Water Heater
- Midstream Indirect Water Heater: For indirect water heaters the baseline is a hot water boiler operating at 78% recovery efficiency. Additionally, a baseline storage water heater was assumed for purpose of estimating standby losses. [1]
- Midstream On Demand Tankless Water Heater, Gas: For on-demand tankless water heaters the baseline is a code-compliant gas-fired storage water heater with EF = 0.61.[1]
- Midstream Volume Water Heater, Gas: The assumed baseline is a code specified 80% TE volume water heater.
- Midstream Condensing Water Heater, Gas: The assumed baseline is a code specified 80% TE water heater.

High Efficiency:

- Midstream Heat Pump Water Heater
- Midstream Indirect Water Heater: The high efficiency scenario is an indirect water heater with a Combined Appliance Efficiency (CAE) of 85% or greater.
- Midstream On Demand Tankless Water Heater, Gas: The high efficiency equipment is either a gas-fired instantaneous hot water heater with an Energy Factor of at least 0.90.

- Midstream Volume Water Heater, Gas: The high efficiency case is a volume water heater with a 94% TE
- Midstream Condensing Water Heater, Gas: The high efficiency case is a high efficiency stand alone commercial water heater with a thermal efficiency of 94% or greater and a capacity greater than 75,000 btu/h.
-

Algorithms for Calculating Primary Energy Impact:

Unit savings are deemed based on study results.

BC Measure ID	Measure Name	Program	ΔkWh	ΔMMBtu	ΔMMBtu / Mbtuh
E21C1c044 E21C2c044	Midstream Heat Pump Water Heater, 120 gallons	LBES Mid SBES Mid			
E21C1c046 E21C2c046	Midstream Heat Pump Water Heater, 80 gallons	LBES Mid SBES Mid			
E21C1c045 E21C2c045	Midstream Heat Pump Water Heater, 50 gallons	LBES Mid SBES Mid	914.63		
G21C1c009 G21C2c009	Midstream Indirect Water Heater	LBES Mid SBES Mid		19.0[2]	
G21C1c010 G21C2c010	Midstream on Demand Tankless Water Heater	LBES Mid SBES Mid		8.9[2]	
G21C1c011 G21C2c011	Midstream Volume Water Heater	LBES Mid SBES Mid			0.6077[2]
G21C1c012 G21C2c012	Midstream Condensing Gas Water Heater	LBES Mid SBES Mid			0.1441[2]

Measure Life:

BC Measure ID	Measure Name	Program	Measure Life
E21C1c044 E21C2c044 E21C1c045 E21C2c045 E21C1c046 E21C2c046	Midstream Heat Pump Water Heater, 120 gallons Midstream Heat Pump Water Heater, 80 gallons Midstream Heat Pump Water Heater, 50 gallons	LBES Mid SBES Mid	13[6]
G21C1c009 G21C2c009	Midstream Indirect Water Heater:	LBES Mid SBES Mid	15 [3]
G21C1c010 G21C2c010	Midstream on Demand Tankless Water Heater, Gas:	LBES Mid SBES Mid	20 [4]
G21C1c011	Midstream Volume Water Heater, Gas:	LBES Mid	15[3]

G21C2c011		SBES Mid	
G21C1c012 G21C2c012	Midstream Condensing Gas Water Heater	LBES Mid SBES Mid	15[3]

Other Resource Impacts:

There are no other resource impacts identified for this measure.

Impact Factors for Calculating Adjusted Gross Savings:

BC Measure ID	Measure Name	Program	ISR	RR_E	RR_{NE}	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
E21C1c044 E21C2c044	Midstream Heat Pump Water Heater, 120 gallons	LBES Mid SBES Mid	1.00	1.00	n/a	n/a	n/a	0.413	0.747
E21C1c046 E21C2c046	Midstream Heat Pump Water Heater, 80 gallons	LBES Mid SBES Mid	1.00	1.00	n/a	n/a	n/a	0.413	0.747
E21C1c045 E21C2c045	Midstream Heat Pump Water Heater, 50 gallons	LBES Mid SBES Mid	1.00	1.00	n/a	n/a	n/a	0.413	0.747
G21C1c009 G21C2c009	Midstream Indirect Water Heater	LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1c010 G21C2c010	Midstream on Demand Tankless Water Heater, Gas	LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1c011 G21C2c011	Midstream Volume Water Heater, Gas	LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a
G21C1c012 G21C2c012	Midstream Condensing Gas Water Heater	LBES Mid SBES Mid	1.00	n/a	1.00	n/a	n/a	n/a	n/a

<u>In-Service Rates:</u>

All installations have a 100% in-service rate unless an evaluation finds otherwise.

<u>Realization Rates:</u>

All programs use a 100% realization rate unless an evaluation finds otherwise.

<u>Coincidence Factors:</u>

A summer coincidence factor of 43.1% and a winter coincidence factor of 74.7% are utilized.

Energy Load Shape:

For heat pump water heaters, see Appendix 1 – “ Water Heater - Heat Pump”.
For all remaining water heaters, see Appendix 1 – “ Water Heater – Natural Gas/Fuel Oil”.

Impact Factors for Calculating Net Savings (Upstream/Midstream Only):[5,7]

BC Measure ID	Measure Name	Program	FR	SO_P	SO_{NP}	2021 NTG
E21C1c044 E21C2c044 E21C1c045 E21C2c045 E21C1c046 E21C2c046	Midstream Heat Pump Water Heater, 120 gallons Midstream Heat Pump Water Heater, 80 gallons Midstream Heat Pump Water Heater, 50 gallons	LBES Mid SBES Mid	22.5%	8.5%	0.0%	86%
G21C1c009 G21C2c009	Midstream Indirect Water Heater	LBES Mid SBES Mid	70.00%	0.0%	0.0%	30.00%
G21C1c010 G21C2c010	Midstream on Demand Tankless Water Heater	LBES Mid SBES Mid	40.0%	0%	0.0%	60.00%
G21C1c011 G21C2c011	Midstream Volume Water Heater	LBES Mid SBES Mid	40.0%	0%	0.0%	60.00%
G21C1c012 G21C2c012	Midstream Condensing Gas Water Heater	LBES Mid SBES Mid	70.00%	0%	0.0%	30.00%

Endnotes:
1: Title 10, Code of Federal Regulations, Part 430 - Energy Conservation Program for Consumer Products, Subpart C - Energy and Water Conservation Standards and Their Effective Dates. January 1, 2010; Energy Conservation standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters: Final Rule, Federal Register, 75 FR 20112, April 16, 2010
2: Savings for indirect water heaters are based on: KEMA, June 27, 2013. Impact Evaluation of 2011 Prescriptive Gas Measures Final Report. https://ma-eeac.org/wp-content/uploads/Impact-Evaluation-of-2011-Prescription-Gas-Measures-6.27.13.pdf
For volume and tankless water heaters, savings are based on: Massachusetts Technical Reference Manual for Estimating Savings from Energy Efficiency Measures. 2019 Plan-Year Report Version. May 2020.
3: GDS Associates, Inc. (2009). Natural Gas Energy Efficiency Potential in Massachusetts. Prepared for GasNetworks;
4: Hewitt, D. Pratt, J. & Smith, G., December 2005. Tankless Gas Water Heaters: Oregon Market Status. Prepared for the Energy Trust of Oregon. https://www.energytrust.org/wp-content/uploads/2016/11/051206_TanklessGasWaterHeaters0.pdf
5: NMR, DNV GL, and Tetra Tech, August 2018. Massachusetts Sponsors' Commercial and Industrial Programs Free-ridership and Spillover Study. Prepared for Massachusetts Program Administrators. http://ma-eeac.org/wordpress/wp-content/uploads/TXC_49_CI-FR-SO-Report_14Aug2018.pdf
6: Navigant Consulting (2018). Water Heating, Boiler, and Furnace Cost Study (RES 19) Add-On Task Residential Water Heater Analysis Memo. 2018 Navigant Water Heater Analysis Memo
7: DNV GL, NMR, Tetra Tech (2018) Massachusetts Commercial and Industrial Upstream HVAC/Heat Pump and Hot Water NTG and Market Effects Indicator Study. https://ma-eeac.org/wp-content/uploads/TXC_35_Report_5Sep2018_FINAL.pdf

Appendix 1: Energy Load Shapes

The section includes a table or reference with the time-of-use pattern of a typical customer's electrical energy consumption for each segment and end use. Because the value of avoided energy varies throughout the year, load shapes are used to allocate energy savings into specific time periods in order to better reflect its time-dependent value. Load shapes are defined as follows based on ISO-NE definitions:

- Summer On-Peak: 7 am to 11 pm, weekdays, during the months of June through September, except ISO-NE holidays;
- Summer Off-Peak: All other hours during the months of June through September (includes weekends and holidays);
- Winter On-Peak: 7 am to 11 pm, weekdays, during the months of October through May, except ISO-NE holidays; and
- Winter Off-Peak: All other hours during the months of October through May (includes weekends and holidays).

Table A1.1. Residential Energy Load Shapes

Load Shape Description	Total Energy			
	Summer		Winter	
	On Peak	Off Peak	On Peak	Off Peak
Non-Electric Measures	0.0%	0.0%	0.0%	0.0%
Clothes Washer	18.3%	15.4%	36.4%	29.9%
24-hour operation	15.2%	18.3%	30.5%	36.1%
Clothes Dryer - Electric	16.9%	14.2%	38.9%	30.0%
Clothes Dryer - Natural Gas	15.9%	16.4%	37.6%	30.1%
Hardwired Electric Heat	0.0%	0.0%	43.1%	56.9%
Lighting	19.0%	15.1%	35.1%	30.7%
Primary TV and Peripherals	15.4%	17.6%	32.2%	34.8%
Primary Desktop Computer	17.5%	17.3%	33.5%	31.7%
Primary Refrigerator	18.2%	20.9%	29.0%	31.9%
Secondary Refrigerator	19.9%	23.6%	26.3%	30.2%
Freezer	17.1%	20.7%	28.7%	33.6%
Dehumidifier	24.9%	29.7%	22.0%	23.3%
Pool Pump	54.5%	38.2%	4.9%	2.4%
Dishwasher	14.8%	16.3%	34.1%	34.8%
Water Heater - Electric	15.2%	11.9%	41.5%	31.4%
Water Heater - Heat Pump	14.9%	13.0%	39.1%	33.0%
Water Heater - Natural Gas/Fuel Oil	13.3%	11.6%	40.9%	34.2%
Central Air Conditioner/Heat Pump (Cooling)	47.3%	42.2%	6.6%	3.8%
Room or Window Air Conditioner	47.5%	47.4%	2.9%	2.2%

Mini-Split Air Conditioner/Heat Pump (Cooling)	43.4%	40.2%	7.4%	9.0%
Mini-Split Heat Pump (Heating)	0.0%	0.0%	42.9%	57.1%
Furnace Fan	0.0%	0.0%	44.6%	55.4%
Boiler Distribution	0.0%	0.0%	45.0%	55.0%
Weighted HVAC - All Homes	23.2%	21.7%	25.4%	29.7%
Weighted HVAC - Multi-family	25.2%	23.7%	23.2%	27.9%
Weighted HVAC - Multi-family Low Income	22.4%	21.6%	25.4%	30.6%
Weighted HVAC - Single Family	22.5%	20.8%	26.1%	30.5%
Weighted HVAC - Single Family Low Income	23.1%	21.7%	25.3%	29.9%
Central Heat Pump	10.1%	9.0%	35.1%	45.7%
DMSHP	8.0%	7.4%	36.4%	48.2%
Electric Resistance with AC	6.0%	5.0%	45.0%	44.0%

Source: Navigant (2018). RES1 Demand Impact Model Update

Table A1.2. Commercial and Industrial Energy Load Shapes

C&I energy load shapes, except where noted in the chapters, are derived from site-level metering of project sites in MA. See DNV GL, 2018. P72 Prescriptive C&I Load shapes of Savings.

Load Shape Description	Total Energy			
	Summer		Winter	
	On Peak	**Off Peak**	**On Peak**	**Off Peak**
C&I Compressed Air - VFD Compressor	26.5%	23.7%	25.9%	23.9%
C&I Compressed Air - Air Dryer	22.4%	27.7%	21.7%	28.1%
C&I Electric Chiller (Combined)	39.4%	38.5%	11.3%	10.8%
C&I Electric Cooling Unitary Equipment	52.7%	34.1%	8.6%	4.6%
C&I Exterior Lighting	19.2%	29.0%	20.1%	31.6%
C&I Interior Lighting - Prescriptive	34.3%	18.1%	30.3%	17.4%
C&I Interior Lighting - Custom	32.3%	19.4%	29.8%	18.6%
C&I Lighting Controls	32.1%	17.7%	31.3%	19.0%
C&I Refrigeration	23.3%	26.8%	22.6%	27.3%
C&I VFDs (Combined)	23.8%	25.3%	23.7%	27.2%
C&I Food Services	16.0%	17.0%	32.0%	35.0%
C&I Heating & Cooling	34.9%	22.1%	26.4%	16.6%

Appendix 2: Equivalent Full Load Hours

Equivalent full load hours (EFLH) are the number of hours a heating or cooling system would have to operate at full load to equal the amount of heating or cooling delivered by the system. Heating and cooling EFLH are tabulated for 21 standard building types and three representative cities in New Hampshire. The EFLH values are based on building energy simulations of prototypical buildings.[4] TMY3 long term average weather data for the three New Hampshire cities were used to drive the simulation models.

Zone	**Representative Cities**
Zone 1- South	Manchester, Portsmouth
Zone 2 - Central	Concord, Keene, Laconia, Lebanon
Zone 3- North	Berlin

The building types are described as follows:

Building Type	*Description*
Assembly	Public buildings that include community centers, libraries, performance and movie theaters, auditoria, police and fire stations, gymnasia, sports arenas, andtransportation terminals
Auto	Repair shops and auto dealerships, including parking lots and parking structures.
Big Box	Single story, high-bay retail stores with ceiling heights of 25 feet or more. Majority of floor space is dedicated to non-food items but could include refrigerated andnon-refrigerated food sales areas.
Community College	Community college campus and post-secondary technical and vocational education buildings, including classroom, computer labs, dining and office. Conditioned by packaged HVAC systems
Dormitory	College or University dormitories
Fast Food	Self-service restaurants with primarily disposable plates, utensils etc.
Full ServiceRestaurant	Full service restaurants with full dishwashing facilities
Grocery	Refrigerated and non-refrigerated food sales, including convenience stores and specialty food sales
Hospital	Inpatient and outpatient care facility conditioned by built-up HVAC systems.Excludes medical offices
Hotel	Multifunction lodging facility with guest rooms, meeting space, foodservice conditioned by built-up HVAC system
Large Office	Office space in buildings greater than 3 stories conditioned by built-up HVACsystem.

[4] Prototypical building models are described in the New York Technical Reference Manual v. 8 Appendix A.

Building Type	*Description*
Light Industrial	Single story work space with heating and air-conditioning; conditioned by packaged HVAC systems
Motel	Lodging facilities with primarily guest room space served by packaged HVACsystems
Large Retail	Retail building with 2 or more stories served by built-up HVAC system
Primary School	K-8 school
Religious	Religious worship
Secondary School	9-12 school
Small Office	Office occupancy in buildings 3 stories or less served by packaged HVAC systems; includes Medical offices
Small Retail	Single story retail with ceiling height of less than 25 feet; primarily non-food retail and storage areas served by packaged HVAC systems. Includes service businesses, post offices, Laundromats, and exercise facilities.
University	University campus buildings, including classroom, computer labs, biological and/or chemical labs, workshop space, dining and office. Conditioned by built-up HVAC systems
Warehouse	Primarily non-refrigerated storage space could include attached offices served by packaged HVAC system.
Other	Use these values if building type is not known

EFLH data for large commercial buildings with built-up HVAC systems are broken out by HVAC system type:

- CV noecon Constant volume reheat system without an airside economizer
- CV econ Constant volume reheat system with an airside economizer
- VAV Variable air volume system with an airside economizer
- Unknown Weighted average of the three HVAC types above used if HVAC system type is not known

Small Commercial Cooling Full Load Hours

Building Type	Berlin	Concord	Manchester
Assembly	448	538	492
Auto Repair	186	304	341
Big Box Retail	734	841	786
Dormatory	638	698	705
Fast Food Restaurant	427	539	521
Full Service Restaurant	391	512	479
Grocery	2,143	2,188	2,028
Light Industrial	350	435	419
Motel	670	900	909
Primary School	167	304	278
Religious	171	220	261
Small Office	563	786	758
Small Retail	575	716	685
Warehouse	172	249	275
Other	545	659	638

Small Commercial Heating Full Load Hours

Building Type	Berlin	Concord	Manchester
Assembly	1,234	960	908
Auto Repair	4,173	3,370	3,379
Big Box Retail	744	602	474
Dormatory	686	544	452
Fast Food Restaurant	1,837	1,400	1,249
Full Service Restaurant	1,886	1,303	1,275
Grocery	951	1,064	988
Light Industrial	1,379	1,265	949
Motel	736	626	499
Primary School	1,551	1,309	1,094
Religious	1,129	1,012	928
Small Office	894	760	588
Small Retail	1,264	1,052	795
Warehouse	1,172	920	829
Other	1,403	1,156	1,029

Large Commercial Cooling Full Load Hours

Building Type	HVAC Type	Berlin	Concord	Manchester
Community College	CV econ	412	627	581
	CV noecon	612	874	789
	VAV	299	489	460
	Unknown	365	570	530
High School	CV econ	252	398	330
	CV noecon	707	837	741
	VAV	148	255	196
	Unknown	251	368	301
Hospital	CV econ	1,037	1,132	1,115
	CV noecon	2,248	2,117	1,865
	VAV	1,014	1,089	1,079
	Unknown	1,115	1,175	1,145
Hotel	CV econ	2,838	3,033	2,763
	CV noecon	3,035	3,219	2,983
	VAV	2,811	3,014	2,726
	Unknown	2,937	3,126	2,873
Large Office	CV econ	885	1,095	1,002
	CV noecon	2,500	2,541	2,276
	VAV	584	758	675
	Unknown	739	906	810
Large Retail	CV econ	701	848	832
	CV noecon	1,695	1,654	1,665
	VAV	560	662	656
	Unknown	662	756	750
University	CV econ	566	722	760
	CV noecon	1,334	1,543	1,689
	VAV	413	592	619
	Unknown	579	760	807

Large Commercial Heating Full Load Hours

Building Type	HVAC Type	Berlin	Concord	Manchester
Community College	CV econ	1,103	1,098	939
	CV noecon	982	1,014	863
	VAV	704	462	642
	Unknown	809	646	723
High School	CV econ	806	744	724
	CV noecon	721	699	652
	VAV	383	289	274
	Unknown	501	423	402
Hospital	CV econ	1,140	1,052	703
	CV noecon	1,068	971	641
	VAV	738	781	437
	Unknown	797	818	474
Hotel	CV econ	1,111	955	909
	CV noecon	917	771	671
	VAV	571	432	350
	Unknown	1,014	863	790
Large Office	CV econ	2,140	2,046	1,683
	CV noecon	2,046	1,985	1,620
	VAV	518	428	309
	Unknown	739	651	497
Large Retail	CV econ	1,878	1,827	1,735
	CV noecon	1,755	1,728	1,620
	VAV	775	681	549
	Unknown	942	856	729
University	CV econ	1,515	1,404	1,342
	CV noecon	1,279	1,195	1,135
	VAV	615	852	797
	Unknown	858	991	933

NHSAVES PROGRAMS
2022 Statewide Goals
Statewide & Company-Specific Programs

Description	Program Budget[1]	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Statewide Programs	$ 55,346,564	80,216,382	976,785,502	11,063	10,694	63,411	1,854,868	114,626
Municipal Program	$ 1,943,528	3,776,956	47,041,405	349	361	(450)	840	246
All Other Statewide Programs								
Sub-total	$ 57,290,093	83,993,338	1,023,826,907	11,412	11,055	62,961	1,855,707	114,872
Company Specific Programs[2]	$ 1,889,283	4,252,690	4,252,690	918	592	-	-	12,339
Total Electric	**$ 59,179,376**	**88,246,029**	**1,028,079,597**	**12,330**	**11,647**	**62,961**	**1,855,707**	**127,210**
Gas Utilities								
Statewide Programs	$ 10,932,561	259,729	4,257,359	51	50	164,801	2,743,149	7,186
Company Specific Programs[2]	$ 345,882	-	-			23,173	23,173	41,200
Total Gas	**$ 11,278,443**	**259,729**	**4,257,359**	**51**	**50**	**187,974**	**2,766,322**	**48,386**
Grand Total	**$ 70,457,819**	**88,505,758**	**1,032,336,956**	**12,381**	**11,697**	**250,935**	**4,622,029**	**175,596**

Notes:
(1) Program budgets shown in this report exclude the performance incentive (PI).
(2) Company-specific includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES PROGRAMS
2022 Statewide Goals
Statewide Programs (1)

Description	Program Budget	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Residential								
Home Energy Assistance	$ 11,811,025	1,863,439	25,053,438	299.2	349.5	21,560.0	462,757.2	805
NH Home Performance w/Energy Star	$ 9,254,558	2,482,825	48,326,897	511.0	483.9	56,552.0	1,261,371.3	2,402
EnergyStar® Homes	$ 3,043,343	1,588,200	36,143,248	427.1	42.6	16,048.9	387,206.1	769
EnergyStar® Products	$ 6,189,197	11,243,943	109,095,731	2,252.1	1,668.7	(409.6)	73,838.5	105,689
Sub-total	$ 30,298,124	17,178,408	218,619,314	3,489.3	2,544.6	93,751.3	2,185,173.1	109,665
Commercial & Industrial								
Large Business Energy Solutions	$ 11,989,092	29,529,624	366,696,943	3,522.7	3,671.8	(8,392.8)	(93,421.5)	780
Small Business Energy Solutions	$ 13,059,348	33,508,350	391,469,245	4,051.1	4,477.8	(21,947.1)	(236,884.0)	4,181
Municipal Program	$ 1,943,528	3,776,956	47,041,405	348.8	360.6	(450.0)	839.7	246
Sub-total	$ 26,991,969	66,814,931	805,207,593	7,922.6	8,510.2	(30,789.9)	(329,465.8)	5,207
Total Electric	**$ 57,290,093**	**83,993,338**	**1,023,826,907**	**11,412.0**	**11,054.8**	**62,961.4**	**1,855,707.3**	**114,872**
Gas Utilities								
Residential								
Home Energy Assistance	$ 2,255,688	144,497	2,874,305	22.7	38.1	9,380.6	183,237.1	355
NH Home Performance w/Energy Star	$ 1,539,811	78,684	773,946	16.8	11.8	18,829.4	375,293.1	566
EnergyStar® Homes	$ 936,307	-	-	-	-	7,804.1	192,603.3	355
EnergyStar® Products	$ 1,410,961	36,548	609,109	11.6	0.2	21,301.6	353,879.4	2,892
Sub-total	$ 6,142,766	259,729	4,257,359	51.1	50.0	57,315.7	1,105,012.8	4,168
Commercial & Industrial								
Large Business Energy Solutions	$ 2,569,559	-	-	-	-	71,042.0	1,038,472.4	556
Small Business Energy Solutions	$ 2,220,236	-	-	-	-	36,443.3	599,664.1	2,462
Sub-total	$ 4,789,794	-	-	-	-	107,485.3	1,638,136.5	3,018
Total Gas	**$ 10,932,561**	**259,729**	**4,257,359**	**51.1**	**50.0**	**164,801.0**	**2,743,149.3**	**7,186**
Grand Total	**$ 68,222,653**	**84,253,067**	**1,028,084,266**	**11,463.1**	**11,104.8**	**227,762.4**	**4,598,857**	**122,058**

Notes:
(1) Amounts shown above pertain only to the Statewide programs. The amounts pertaining to the Company-Specific programs are shown on Attachment B, page 3.

NHSAVES PROGRAMS
2022 Statewide Goals
Company-Specific Programs [1]

Description	Program Budget	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Residential								
Home Energy Reports	$ 280,319	4,252,690	4,252,690	918.0	592.2	-	-	10,256
Education	$ 314,016	-	-	-	-	-	-	-
Forward Capacity Market Expenses [2]	$ 73,966	-	-	-	-	-	-	-
Residential Active Demand Response	$ 190,156	-	-	-	-	-	-	2,055
Energy Optimization Pilot	$ -	-	-	-	-	-	-	-
Sub-total	$ 858,456	4,252,690	4,252,690	918.0	592.2	-	-	12,311
Commercial & Industrial								
Smart Start	$ 30,000	-	-	-	-	-	-	-
C&I Customer Partnerships	$ 15,330	-	-	-	-	-	-	-
Education	$ 269,685	-	-	-	-	-	-	-
Forward Capacity Market Expenses [2]	$ 161,637	-	-	-	-	-	-	-
C&I Active Demand Response	$ 554,175	-	-	-	-	-	-	28
Sub-total	$ 1,030,827	-	-	-	-	-	-	28
Total Residential and C&I	**$ 1,889,283**	**4,252,690**	**4,252,690**	**918.0**	**592.2**	**-**	**-**	**12,339**
Gas Utilities								
Residential								
Home Energy Reports	$ 203,194	-	-	-	-	23,172.8	23,172.8	41,200
Education	$ 88,793	-	-	-	-	-	-	-
Residential Financing	$ -	-	-	-	-	-	-	-
AIM Initiative	$ -	-	-	-	-	-	-	-
Sub-total	$ 291,986	-	-	-	-	23,173	23,173	41,200
Commercial & Industrial								
Education	$ 53,896	-	-	-	-	-	-	-
Sub-total	$ 53,896	-	-			-	-	-
Total Residential and C&I	**$ 345,882**	**-**	**-**			**23,173**	**23,173**	**41,200**
Grand Total	**$ 2,235,165**	**4,252,690**	**4,252,690**	**918.0**	**592.2**	**23,172.8**	**23,173**	**53,539**

Notes:
(1) Amounts shown above pertain only to the Company-Specific programs. The amounts pertaining to the Statewide programs are shown on Attachment B, page 2.
Company-specific includes company-specific programs, education, forward capacity market administration and loan program administration.
(2) Amounts shown are budgeted expenses related to the electric utilities' participation in ISO-NE's Forward Capacity Market.

NHSAVES PROGRAMS
2023 Statewide Goals
Statewide & Company-Specific Programs

Description	Program Budget[1]	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Statewide Programs	$ 56,876,940	73,561,107	907,257,325	9,719	9,551	61,307	1,716,402	97,640
Municipal Program	$ 2,000,000	3,578,147	44,760,795	330	318	(348)	1,848	241
All Other Statewide Programs								
Sub-total	$ 58,876,940	77,139,254	952,018,120	10,048	9,869	60,959	1,718,250	97,880
Company Specific Programs[2]	$ 1,948,240	5,030,316	5,030,316	1,086	700	-	-	12,460
Total Electric	**$ 60,825,179**	**82,169,570**	**957,048,436**	**11,134**	**10,569**	**60,959**	**1,718,250**	**110,341**
Gas Utilities								
Statewide Programs	$ 10,989,572	254,704	4,174,684	21	92	153,168	2,604,938	7,127
Company Specific Programs[2]	$ 377,788	-	-			34,257	34,257	41,200
Total Gas	**$ 11,367,360**	**254,704**	**4,174,684**	**21**	**92**	**187,425**	**2,639,195**	**48,327**
Grand Total	**$ 72,192,539**	**82,424,274**	**961,223,120**	**11,155**	**10,661**	**248,384**	**4,357,445**	**158,668**

Notes:
(1) Program budgets shown in this report exclude the performance incentive (PI).
(2) Company-specific includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES PROGRAMS
2023 Statewide Goals
Statewide Programs [1]

Description	Program Budget	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Residential								
Home Energy Assistance	$ 12,123,036	1,791,912	24,303,389	281.8	341.4	20,630.5	440,762.0	798
NH Home Performance w/Energy Star	$ 9,466,186	2,374,495	46,350,340	472.6	485.6	50,658.7	1,121,825.1	2,352
EnergyStar® Homes	$ 3,144,206	1,559,522	35,350,664	385.4	41.6	15,074.0	363,774.8	806
EnergyStar® Products	$ 6,326,235	10,062,045	104,780,286	2,024.0	1,489.0	2,518.0	89,585.3	88,922
Sub-total	$ 31,059,663	15,787,973	210,784,679	3,163.8	2,357.7	88,881.2	2,015,947.2	92,878
Commercial & Industrial								
Large Business Energy Solutions	$ 12,303,161	26,983,246	335,577,902	2,888.5	3,131.8	(7,408.0)	(81,909.4)	707
Small Business Energy Solutions	$ 13,514,116	30,789,888	360,894,744	3,666.3	4,061.1	(20,166.4)	(217,636.3)	4,055
Municipal Program	$ 2,000,000	3,578,147	44,760,795	329.8	317.9	(347.7)	1,848.2	241
Sub-total	$ 27,817,277	61,351,281	741,233,441	6,884.6	7,510.8	(27,922.1)	(297,697.5)	5,002
Total Electric	**$ 58,876,940**	**77,139,254**	**952,018,120**	**10,048.4**	**9,868.5**	**60,959.0**	**1,718,249.7**	**97,880**
Gas Utilities								
Residential								
Home Energy Assistance	$ 2,273,471	146,598	2,912,099	0.0	74.8	9,143.3	177,607.3	364
NH Home Performance w/Energy Star	$ 1,550,274	78,594	772,567	14.2	16.1	18,203.7	365,951.4	422
EnergyStar® Homes	$ 976,919	-	-	-	-	7,919.2	195,478.8	345
EnergyStar® Products	$ 1,385,396	29,512	490,018	6.9	0.6	19,684.4	325,765.4	2,809
Sub-total	$ 6,186,060	254,704	4,174,684	21.1	91.6	54,950.5	1,064,803.0	3,940
Commercial & Industrial								
Large Business Energy Solutions	$ 2,554,133	-	-	-	-	64,307.0	972,003.8	552
Small Business Energy Solutions	$ 2,249,379	-	-	-	-	33,910.5	568,130.9	2,635
Sub-total	$ 4,803,513	-	-	-	-	98,217.5	1,540,134.8	3,187
Total Gas	**$ 10,989,572**	**254,704**	**4,174,684**	**21.1**	**91.6**	**153,168.0**	**2,604,937.7**	**7,127**
Grand Total	**$ 69,866,512**	**77,393,958**	**956,192,804**	**10,069.5**	**9,960.1**	**214,127.1**	**4,323,187**	**105,008**

Notes:
(1) Amounts shown above pertain only to the Statewide programs. The amounts pertaining to the Company-Specific programs are shown on Attachment B, page 3.

NHSAVES PROGRAMS
2023 Statewide Goals
Company-Specific Programs [1]

Description	Program Budget	kWh Savings Annual	kWh Savings Lifetime	kW Savings Winter kW	kW Savings Summer kW	MMBtu Savings Annual	MMBtu Savings Lifetime	Customers Count
Electric Utilities								
Residential								
Home Energy Reports	$ 293,983	5,030,316	5,030,316	1,085.9	700.5	-	-	10,256
Education	$ 302,297	-	-	-	-	-	-	-
Forward Capacity Market Expenses [2]	$ 74,583	-	-	-	-	-	-	-
Residential Active Demand Response	$ 201,051	-	-	-	-	-	-	2,177
Energy Optimization Pilot	$ -	-	-	-	-	-	-	-
Sub-total	$ 871,914	5,030,316	5,030,316	1,085.9	700.5	-	-	12,433
Commercial & Industrial								
Smart Start	$ 30,000	-	-	-	-	-	-	-
C&I Customer Partnerships	$ 12,253	-	-	-	-	-	-	-
Education	$ 265,207	-	-	-	-	-	-	-
Forward Capacity Market Expenses [2]	$ 164,780	-	-	-	-	-	-	-
C&I Active Demand Response	$ 604,086	-	-	-	-	-	-	28
Sub-total	$ 1,076,326	-	-	-	-	-	-	28
Total Residential and C&I	**$ 1,948,240**	**5,030,316**	**5,030,316**	**1,085.9**	**700.5**	**-**	**-**	**12,460**
Gas Utilities								
Residential								
Home Energy Reports	$ 219,827	-	-	-	-	34,257.4	34,257.4	41,200
Education	$ 97,952	-	-	-	-	-	-	-
Residential Financing	$ -	-	-	-	-	-	-	-
AIM Initiative	$ -	-	-	-	-	-	-	-
Sub-total	$ 317,779	-	-	-	-	34,257	34,257	41,200
Commercial & Industrial								
Education	$ 60,009	-	-	-	-	-	-	-
Sub-total	$ 60,009	-	-			-	-	-
Total Residential and C&I	**$ 377,788**	**-**	**-**			**34,257**	**34,257**	**41,200**
Grand Total	**$ 2,326,028**	**5,030,316**	**5,030,316**	**1,085.9**	**700.5**	**34,257.4**	**34,257**	**53,660**

Notes:
(1) Amounts shown above pertain only to the Company-Specific programs. The amounts pertaining to the Statewide programs are shown on Attachment B, page 2.
Company-specific includes company-specific programs, education, forward capacity market administration and loan program administration.
(2) Amounts shown are budgeted expenses related to the electric utilities' participation in ISO-NE's Forward Capacity Market.

NHSAVES ENERGY EFFICIENCY PROGRAM - 2022 UTILITY BUDGETS BY ACTIVITY
Residential Programs

Description		Electric Utilities					Gas Utilities			Grand Total
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	
Home Energy Assistance	Internal Admin	$ 39,666	$ 35,054	$ 151,733	$ 86,922	$ 313,376	$ 56,956	$ 26,435	$ 83,391	$ 396,767
	External Admin	$ 840	$ 15,750	$ 12,833	$ 1,738	$ 31,162	$ 1,207	$ 2,000	$ 3,207	$ 34,368
	Rebate/Services	$ 996,647	$ 827,863	$ 7,487,304	$ 973,428	$ 10,285,242	$ 1,438,961	$ 415,075	$ 1,854,036	$ 12,139,278
	Implementation Services	$ 62,468	$ 72,051	$ 286,004	$ 90,873	$ 511,396	$ 93,568	$ 89,218	$ 182,786	$ 694,182
	Marketing	$ 35,301	$ 25,348	$ 252,639	$ 15,804	$ 329,093	$ 50,965	$ 4,304	$ 55,269	$ 384,362
	EM&V	$ 41,793	$ 32,613	$ 230,792	$ 35,559	$ 340,756	$ 57,173	$ 19,826	$ 76,999	$ 417,756
	Total	$ 1,176,716	$ 1,008,680	$ 8,421,306	$ 1,204,324	$ 11,811,025	$ 1,698,829	$ 556,859	$ 2,255,688	$ 14,066,713
HP w/EnergyStar®	Internal Admin	$ 20,811	$ 35,054	$ 125,535	$ 44,092	$ 225,493	$ 40,464	$ 17,755	$ 58,219	$ 283,712
	External Admin	$ 441	$ 15,750	$ 10,617	$ 882	$ 27,690	$ 857	$ 1,224	$ 2,081	$ 29,771
	Rebate/Services	$ 522,868	$ 807,694	$ 6,194,554	$ 562,535	$ 8,087,651	$ 1,022,021	$ 281,986	$ 1,304,007	$ 9,391,658
	Implementation Services	$ 32,774	$ 72,051	$ 236,623	$ 47,168	$ 388,616	$ 66,476	$ 14,146	$ 80,622	$ 469,238
	Marketing	$ 18,521	$ 25,348	$ 209,019	$ 8,203	$ 261,091	$ 36,208	$ 4,439	$ 40,647	$ 301,739
	EM&V	$ 21,958	$ 32,613	$ 190,944	$ 18,503	$ 264,018	$ 40,918	$ 13,316	$ 54,234	$ 318,252
	Total	$ 617,374	$ 988,510	$ 6,967,291	$ 681,383	$ 9,254,558	$ 1,206,945	$ 332,866	$ 1,539,811	$ 10,794,370
EnergyStar® Homes	Internal Admin	$ 5,732	$ 35,054	$ 33,340	$ 31,597	$ 105,724	$ 21,382	$ 15,744	$ 37,126	$ 142,850
	External Admin	$ 121	$ 15,750	$ 2,820	$ 632	$ 19,323	$ 453	$ 1,085	$ 1,538	$ 20,861
	Rebate/Services	$ 144,355	$ 361,984	$ 1,645,176	$ 399,275	$ 2,550,790	$ 541,244	$ 246,279	$ 787,523	$ 3,338,312
	Implementation Services	$ 9,027	$ 67,700	$ 62,843	$ 33,802	$ 173,372	$ 35,126	$ 19,696	$ 54,823	$ 228,195
	Marketing	$ 5,101	$ 25,348	$ 55,512	$ 5,879	$ 91,840	$ 19,133	$ 3,936	$ 23,069	$ 114,909
	EM&V	$ 5,710	$ 32,613	$ 50,712	$ 13,260	$ 102,294	$ 20,421	$ 11,808	$ 32,229	$ 134,523
	Total	$ 170,047	$ 538,450	$ 1,850,403	$ 484,444	$ 3,043,343	$ 637,758	$ 298,548	$ 936,307	$ 3,979,650
Energy Star® Products	Internal Admin	$ 15,570	$ 35,054	$ 74,049	$ 33,890	$ 158,564	$ 41,787	$ 8,932	$ 50,719	$ 209,283
	External Admin	$ 330	$ 15,750	$ 6,263	$ 678	$ 23,020	$ 885	$ 616	$ 1,501	$ 24,521
	Rebate/Services	$ 392,111	$ 856,292	$ 3,653,977	$ 417,356	$ 5,319,736	$ 1,057,769	$ 128,834	$ 1,186,603	$ 6,506,339
	Implementation Services	$ 24,521	$ 127,897	$ 139,576	$ 36,254	$ 328,249	$ 68,648	$ 13,373	$ 82,021	$ 410,270
	Marketing	$ 13,857	$ 25,348	$ 123,294	$ 15,153	$ 177,652	$ 37,392	$ 6,117	$ 43,508	$ 221,160
	EM&V	$ 15,509	$ 32,613	$ 112,632	$ 21,222	$ 181,976	$ 39,909	$ 6,699	$ 46,608	$ 228,584
	Total	$ 461,898	$ 1,092,955	$ 4,109,791	$ 524,553	$ 6,189,197	$ 1,246,390	$ 164,571	$ 1,410,961	$ 7,600,158

NHSAVES ENERGY EFFICIENCY PROGRAM - 2022 UTILITY BUDGETS BY ACTIVITY
Residential Programs (Continued)

Description		Electric Utilities					Gas Utilities			
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	Grand Total
Other*	Internal Admin	$ 5,116	$ -	$ 5,775	$ 16,810	$ 27,700	$ 7,814	$ 2,121	$ 9,935	$ 37,635
	External Admin	$ 108	$ -	$ 488	$ 336	$ 933	$ 166	$ 146	$ 312	$ 1,245
	Rebate/Services	$ 128,844	$ 23,654	$ 284,947	$ 225,874	$ 663,318	$ 200,063	$ 46,209	$ 246,272	$ 909,590
	Implementation Services	$ 11,877	$ -	$ 82,524	$ 22,003	$ 116,404	$ 12,837	$ 7,507	$ 20,344	$ 136,747
	Marketing	$ 4,553	$ 945	$ 3,695	$ 2,891	$ 12,084	$ 6,992	$ 1,338	$ 8,331	$ 20,415
	EM&V	$ 10,371	$ 6,000	$ 3,375	$ 18,270	$ 38,017	$ 5,203	$ 1,590	$ 6,793	$ 44,810
	Total	$ 160,870	$ 30,599	$ 380,804	$ 286,183	$ 858,456	$ 233,075	$ 58,911	$ 291,986	$ 1,150,442
Total Residential	Internal Admin	$ 86,896	$ 140,218	$ 390,433	$ 213,310	$ 830,857	$ 168,403	$ 70,987	$ 239,390	$ 1,070,247
	External Admin	$ 1,841	$ 63,000	$ 33,021	$ 4,266	$ 102,128	$ 3,567	$ 5,071	$ 8,638	$ 110,766
	Rebate/Services	$ 2,184,825	$ 2,877,487	$ 19,265,958	$ 2,578,467	$ 26,906,737	$ 4,260,057	$ 1,118,383	$ 5,378,441	$ 32,285,178
	Implementation Services	$ 140,668	$ 339,700	$ 807,570	$ 230,099	$ 1,518,037	$ 276,656	$ 143,940	$ 420,596	$ 1,938,633
	Marketing	$ 77,334	$ 102,338	$ 644,159	$ 47,929	$ 871,760	$ 150,690	$ 20,134	$ 170,824	$ 1,042,585
	EM&V	$ 95,341	$ 136,451	$ 588,454	$ 106,814	$ 927,061	$ 163,624	$ 53,240	$ 216,864	$ 1,143,924
	Total	$ 2,586,905	$ 3,659,194	$ 21,729,595	$ 3,180,887	$ 31,156,580	$ 5,022,997	$ 1,411,755	$ 6,434,752	$ 37,591,333
Total %	Internal Admin	3.4%	3.8%	1.8%	6.7%	2.7%	3.4%	5.0%	3.7%	2.8%
	External Admin	0.1%	1.7%	0.2%	0.1%	0.3%	0.1%	0.4%	0.1%	0.3%
	Rebate/Services	84.5%	78.6%	88.7%	81.1%	86.4%	84.8%	79.2%	83.6%	85.9%
	Implementation Services	5.4%	9.3%	3.7%	7.2%	4.9%	5.5%	10.2%	6.5%	5.2%
	Marketing	3.0%	2.8%	3.0%	1.5%	2.8%	3.0%	1.4%	2.7%	2.8%
	EM&V	3.7%	3.7%	2.7%	3.4%	3.0%	3.3%	3.8%	3.4%	3.0%
	Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

* Other includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES ENERGY EFFICIENCY PROGRAM - 2022 UTILITY BUDGETS BY ACTIVITY
C&I and Municipal Programs

		Electric Utilities					Gas Utilities			
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	Grand Total
Large Business Energy Solutions	Internal Admin	$ 42,611	$ 34,999	$ 152,861	$ 105,238	$ 335,709	$ 63,307	$ 35,361	$ 98,668	$ 434,377
	External Admin	$ 903	$ 15,725	$ 12,928	$ 4,040	$ 33,596	$ 1,341	$ 1,500	$ 2,841	$ 36,437
	Rebate/Services	$ 1,073,095	$ 487,310	$ 7,542,936	$ 941,492	$ 10,044,832	$ 1,602,523	$ 568,893	$ 2,171,416	$ 12,216,248
	Implementation Services	$ 67,106	$ 115,572	$ 585,105	$ 110,022	$ 877,804	$ 104,003	$ 38,581	$ 142,583	$ 1,020,387
	Marketing	$ 37,922	$ 26,868	$ 263,701	$ 23,918	$ 352,410	$ 56,649	$ 10,420	$ 67,069	$ 419,478
	EM&V	$ 42,444	$ 29,194	$ 232,507	$ 40,596	$ 344,741	$ 60,462	$ 26,520	$ 86,982	$ 431,723
	Total	$ 1,264,081	$ 709,668	$ 8,790,037	$ 1,225,306	$ 11,989,092	$ 1,888,284	$ 681,275	$ 2,569,559	$ 14,558,651
Small Business Energy Solutions	Internal Admin	$ 51,656	$ 34,999	$ 165,566	$ 101,601	$ 353,822	$ 51,794	$ 35,042	$ 86,836	$ 440,658
	External Admin	$ 1,094	$ 15,725	$ 14,003	$ 3,912	$ 34,734	$ 1,097	$ 1,500	$ 2,597	$ 37,331
	Rebate/Services	$ 1,300,880	$ 595,601	$ 8,169,880	$ 908,597	$ 10,974,957	$ 1,311,074	$ 561,697	$ 1,872,770	$ 12,847,728
	Implementation Services	$ 81,351	$ 121,305	$ 633,737	$ 106,219	$ 942,611	$ 85,088	$ 38,472	$ 123,560	$ 1,066,171
	Marketing	$ 45,972	$ 26,868	$ 285,619	$ 23,091	$ 381,551	$ 46,346	$ 12,380	$ 58,726	$ 440,277
	EM&V	$ 51,453	$ 29,194	$ 251,832	$ 39,193	$ 371,673	$ 49,466	$ 26,281	$ 75,747	$ 447,419
	Total	$ 1,532,407	$ 823,693	$ 9,520,636	$ 1,182,612	$ 13,059,348	$ 1,544,864	$ 675,372	$ 2,220,236	$ 15,279,584
Municipal	Internal Admin	$ 5,304	$ 12,353	$ 23,917	$ 21,706	$ 63,279	$ -	$ -	$ -	$ 63,279
	External Admin	$ 112	$ 5,550	$ 2,023	$ 434	$ 8,119	$ -	$ -	$ -	$ 8,119
	Rebate/Services	$ 133,565	$ 138,841	$ 1,180,176	$ 158,522	$ 1,611,103	$ -	$ -	$ -	$ 1,611,103
	Implementation Services	$ 8,353	$ 23,422	$ 91,546	$ 22,692	$ 146,013	$ -	$ -	$ -	$ 146,013
	Marketing	$ 4,720	$ 5,812	$ 41,259	$ 4,933	$ 56,724	$ -	$ -	$ -	$ 56,724
	EM&V	$ 5,283	$ 7,749	$ 36,378	$ 8,880	$ 58,290	$ -	$ -	$ -	$ 58,290
	Total	$ 157,337	$ 193,726	$ 1,375,299	$ 217,167	$ 1,943,528	$ -	$ -	$ -	$ 1,943,528
Other*	Internal Admin	$ 841	$ -	$ 12,125	$ 16,576	$ 29,542	$ 1,274	$ -	$ 1,274	$ 30,816
	External Admin	$ 18	$ -	$ 1,025	$ 332	$ 1,375	$ 27	$ -	$ 27	$ 1,402
	Rebate/Services	$ 21,180	$ 13,892	$ 598,317	$ 156,143	$ 789,532	$ 33,466	$ 9,561	$ 43,027	$ 832,559
	Implementation Services	$ 10,237	$ -	$ 100,384	$ 20,840	$ 131,461	$ 2,093	$ 5,300	$ 7,393	$ 138,853
	Marketing	$ 749	$ 555	$ 11,362	$ 3,977	$ 16,642	$ 1,140	$ 1,036	$ 2,176	$ 18,818
	EM&V	$ 13,146	$ 14,000	$ 10,018	$ 25,111	$ 62,275	$ -	$ -	$ -	$ 62,275
	Total	$ 46,171	$ 28,447	$ 733,231	$ 222,978	$ 1,030,827	$ 38,000	$ 15,896	$ 53,896	$ 1,084,723

* Other includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES ENERGY EFFICIENCY PROGRAM - 2022 UTILITY BUDGETS BY ACTIVITY
C&I and Municipal Program Total and Grand Total (Residential, C&I and Municipal)

		Electric Utilities					Gas Utilities			
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	Grand Total
Total C&I and Municipal	Internal Admin	$ 100,413	$ 82,350	$ 354,469	$ 245,120	$ 782,352	$ 116,375	$ 70,403	$ 186,778	$ 969,130
	External Admin	$ 2,127	$ 37,000	$ 29,979	$ 8,718	$ 77,824	$ 2,465	$ 3,000	$ 5,465	$ 83,289
	Rebate/Services	$ 2,528,720	$ 1,235,644	$ 17,491,308	$ 2,164,754	$ 23,420,425	$ 2,947,062	$ 1,140,151	$ 4,087,213	$ 27,507,638
	Implementation Services	$ 167,046	$ 260,299	$ 1,410,771	$ 259,773	$ 2,097,889	$ 191,183	$ 82,352	$ 273,536	$ 2,371,425
	Marketing	$ 89,363	$ 60,103	$ 601,941	$ 55,919	$ 807,327	$ 104,134	$ 23,836	$ 127,970	$ 935,297
	EM&V	$ 112,326	$ 80,138	$ 530,735	$ 113,780	$ 836,979	$ 109,928	$ 52,801	$ 162,729	$ 999,707
	Total	$ 2,999,995	$ 1,755,534	$ 20,419,203	$ 2,848,063	$ 28,022,795	$ 3,471,148	$ 1,372,543	$ 4,843,691	$ 32,866,486
Total C&I and Municipal %	Internal Admin	3.3%	4.7%	1.7%	8.6%	2.8%	3.4%	5.1%	3.9%	2.9%
	External Admin	0.1%	2.1%	0.1%	0.3%	0.3%	0.1%	0.2%	0.1%	0.3%
	Rebate/Services	84.3%	70.4%	85.7%	76.0%	83.6%	84.9%	83.1%	84.4%	83.7%
	Implementation Services	5.6%	14.8%	6.9%	9.1%	7.5%	5.5%	6.0%	5.6%	7.2%
	Marketing	3.0%	3.4%	2.9%	2.0%	2.9%	3.0%	1.7%	2.6%	2.8%
	EM&V	3.7%	4.6%	2.6%	4.0%	3.0%	3.2%	3.8%	3.4%	3.0%
	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Grand Total (Residential, C&I and Municipal)	Internal Admin	$ 187,309	$ 222,568	$ 744,902	$ 458,431	$ 1,613,209	$ 284,778	$ 141,390	$ 426,168	$ 2,039,377
	External Admin	$ 3,968	$ 100,000	$ 63,000	$ 12,984	$ 179,952	$ 6,033	$ 8,071	$ 14,103	$ 194,055
	Rebate/Services	$ 4,713,545	$ 4,113,130	$ 36,757,266	$ 4,743,221	$ 50,327,163	$ 7,207,120	$ 2,258,534	$ 9,465,654	$ 59,792,816
	Implementation Services	$ 307,714	$ 599,999	$ 2,218,341	$ 489,872	$ 3,615,926	$ 467,839	$ 226,292	$ 694,132	$ 4,310,058
	Marketing	$ 166,698	$ 162,442	$ 1,246,100	$ 103,848	$ 1,679,087	$ 254,824	$ 43,970	$ 298,795	$ 1,977,882
	EM&V	$ 207,667	$ 216,589	$ 1,119,189	$ 220,594	$ 1,764,039	$ 273,552	$ 106,041	$ 379,592	$ 2,143,632
	Total	$ 5,586,900	$ 5,414,728	$ 42,148,798	$ 6,028,950	$ 59,179,376	$ 8,494,145	$ 2,784,298	$ 11,278,443	$ 70,457,818
Grand Total % (Residential, C&I and Municipal)	Internal Admin	3.4%	4.1%	1.8%	7.6%	2.7%	3.4%	5.1%	3.8%	2.9%
	External Admin	0.1%	1.8%	0.1%	0.2%	0.3%	0.1%	0.3%	0.1%	0.3%
	Rebate/Services	84.4%	76.0%	87.2%	78.7%	85.0%	84.8%	81.1%	83.9%	84.9%
	Implementation Services	5.5%	11.1%	5.3%	8.1%	6.1%	5.5%	8.1%	6.2%	6.1%
	Marketing	3.0%	3.0%	3.0%	1.7%	2.8%	3.0%	1.6%	2.6%	2.8%
	EM&V	3.7%	4.0%	2.7%	3.7%	3.0%	3.2%	3.8%	3.4%	3.0%
	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

NHSAVES ENERGY EFFICIENCY PROGRAM - 2023 UTILITY BUDGETS BY ACTIVITY
Residential Programs

Description		Electric Utilities					Gas Utilities			Grand Total
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	
Home Energy Assistance	Internal Admin	$ 37,208	$ 36,106	$ 151,185	$ 91,268	$ 315,767	$ 60,928	$ 29,530	$ 90,458	$ 406,225
	External Admin	$ 925	$ 11,813	$ 12,786	$ 1,906	$ 27,430	$ 1,504	$ 1,777	$ 3,281	$ 30,711
	Rebate/Services	$ 879,666	$ 683,907	$ 7,774,042	$ 1,067,032	$ 10,404,647	$ 1,484,838	$ 353,798	$ 1,838,637	$ 12,243,284
	Implementation Services	$ 57,603	$ 70,679	$ 298,831	$ 95,417	$ 522,530	$ 100,094	$ 86,082	$ 186,176	$ 708,706
	Marketing	$ 31,718	$ 19,949	$ 267,207	$ 16,959	$ 335,832	$ 53,357	$ 4,580	$ 57,937	$ 393,770
	EM&V	$ 50,145	$ 25,413	$ 402,840	$ 38,431	$ 516,830	$ 77,852	$ 19,129	$ 96,981	$ 613,811
	Total	$ 1,057,265	$ 847,867	$ 8,906,891	$ 1,311,013	$ 12,123,036	$ 1,778,574	$ 494,897	$ 2,273,471	$ 14,396,507
HP w/EnergyStar®	Internal Admin	$ 19,707	$ 36,106	$ 127,959	$ 46,296	$ 230,068	$ 40,824	$ 22,917	$ 63,741	$ 293,809
	External Admin	$ 490	$ 11,813	$ 10,822	$ 907	$ 24,032	$ 1,008	$ 1,285	$ 2,292	$ 26,324
	Rebate/Services	$ 465,900	$ 500,000	$ 6,579,747	$ 579,286	$ 8,124,933	$ 994,896	$ 287,127	$ 1,282,023	$ 9,406,956
	Implementation Services	$ 30,509	$ 70,679	$ 252,922	$ 49,526	$ 403,636	$ 67,067	$ 18,960	$ 86,026	$ 489,662
	Marketing	$ 16,799	$ 19,949	$ 226,157	$ 8,525	$ 271,429	$ 35,751	$ 5,195	$ 40,946	$ 312,376
	EM&V	$ 26,558	$ 25,413	$ 340,953	$ 19,163	$ 412,088	$ 52,163	$ 23,081	$ 75,245	$ 487,333
	Total	$ 559,963	$ 663,959	$ 7,538,561	$ 703,703	$ 9,466,186	$ 1,191,709	$ 358,565	$ 1,550,274	$ 11,016,459
EnergyStar® Homes	Internal Admin	$ 7,408	$ 36,106	$ 33,920	$ 33,177	$ 110,611	$ 22,107	$ 20,321	$ 42,428	$ 153,039
	External Admin	$ 184	$ 11,813	$ 2,869	$ 650	$ 15,516	$ 546	$ 1,139	$ 1,685	$ 17,200
	Rebate/Services	$ 175,140	$ 275,000	$ 1,744,172	$ 411,518	$ 2,605,830	$ 538,744	$ 270,888	$ 809,631	$ 3,415,461
	Implementation Services	$ 11,469	$ 66,411	$ 67,045	$ 35,492	$ 180,417	$ 36,317	$ 15,627	$ 51,945	$ 232,361
	Marketing	$ 6,315	$ 19,949	$ 59,950	$ 6,109	$ 92,323	$ 19,360	$ 3,156	$ 22,516	$ 114,839
	EM&V	$ 9,984	$ 25,413	$ 90,381	$ 13,732	$ 139,510	$ 28,247	$ 20,467	$ 48,714	$ 188,224
	Total	$ 210,500	$ 434,692	$ 1,998,336	$ 500,678	$ 3,144,206	$ 645,320	$ 331,599	$ 976,919	$ 4,121,125
Energy Star® Products	Internal Admin	$ 14,928	$ 36,106	$ 75,770	$ 35,585	$ 162,388	$ 41,510	$ 11,529	$ 53,039	$ 215,428
	External Admin	$ 371	$ 11,813	$ 6,408	$ 697	$ 19,289	$ 1,025	$ 646	$ 1,671	$ 20,960
	Rebate/Services	$ 352,930	$ 677,777	$ 3,896,123	$ 429,729	$ 5,356,559	$ 1,011,615	$ 119,391	$ 1,131,006	$ 6,487,565
	Implementation Services	$ 23,111	$ 125,461	$ 149,765	$ 38,067	$ 336,404	$ 68,194	$ 22,727	$ 90,921	$ 427,326
	Marketing	$ 12,726	$ 19,949	$ 133,916	$ 15,652	$ 182,242	$ 36,352	$ 7,754	$ 44,106	$ 226,349
	EM&V	$ 20,119	$ 25,413	$ 201,892	$ 21,928	$ 269,352	$ 53,040	$ 11,612	$ 64,652	$ 334,004
	Total	$ 424,185	$ 896,519	$ 4,463,873	$ 541,658	$ 6,326,235	$ 1,211,736	$ 173,660	$ 1,385,396	$ 7,711,631

NHSAVES ENERGY EFFICIENCY PROGRAM - 2023 UTILITY BUDGETS BY ACTIVITY
Residential Programs (Continued)

Description		Electric Utilities: Liberty	Electric Utilities: NHEC	Electric Utilities: Eversource	Electric Utilities: Unitil	Sub-total Electric	Gas Utilities: Liberty	Gas Utilities: Unitil	Sub-total Gas	Grand Total
Other*	Internal Admin	$ 5,582	$ -	$ 5,554	$ 17,650	$ 28,786	$ 8,648	$ 2,737	$ 11,386	$ 40,172
	External Admin	$ 98	$ -	$ 470	$ 605	$ 1,173	$ 213	$ 153	$ 367	$ 1,540
	Rebate/Services	$ 134,770	$ 22,610	$ 285,609	$ 225,502	$ 668,490	$ 214,149	$ 35,412	$ 249,562	$ 918,052
	Implementation Services	$ 11,991	$ -	$ 79,801	$ 22,623	$ 114,415	$ 14,208	$ 23,917	$ 38,125	$ 152,539
	Marketing	$ 4,758	$ 945	$ 3,952	$ 4,192	$ 13,847	$ 7,574	$ 342	$ 7,916	$ 21,763
	EM&V	$ 10,769	$ 6,000	$ 5,958	$ 22,476	$ 45,203	$ 7,667	$ 2,757	$ 10,424	$ 55,627
	Total	$ 167,968	$ 29,555	$ 381,343	$ 293,048	$ 871,914	$ 252,460	$ 65,319	$ 317,779	$ 1,189,693
Total Residential	Internal Admin	$ 84,832	$ 144,424	$ 394,388	$ 223,976	$ 847,620	$ 174,018	$ 87,034	$ 261,052	$ 1,108,672
	External Admin	$ 2,070	$ 47,250	$ 33,355	$ 4,765	$ 87,440	$ 4,295	$ 5,001	$ 9,296	$ 96,736
	Rebate/Services	$ 2,008,406	$ 2,159,294	$ 20,279,692	$ 2,713,067	$ 27,160,459	$ 4,244,242	$ 1,066,617	$ 5,310,859	$ 32,471,318
	Implementation Services	$ 134,683	$ 333,229	$ 848,364	$ 241,125	$ 1,557,401	$ 285,880	$ 167,313	$ 453,193	$ 2,010,594
	Marketing	$ 72,315	$ 80,740	$ 691,182	$ 51,437	$ 895,674	$ 152,394	$ 21,027	$ 173,421	$ 1,069,095
	EM&V	$ 117,575	$ 107,653	$ 1,042,024	$ 115,731	$ 1,382,983	$ 218,969	$ 77,047	$ 296,016	$ 1,678,999
	Total	$ 2,419,881	$ 2,872,591	$ 23,289,005	$ 3,350,100	$ 31,931,577	$ 5,079,799	$ 1,424,039	$ 6,503,838	$ 38,435,415
Total %	Internal Admin	3.5%	5.0%	1.7%	6.7%	2.7%	3.4%	6.1%	4.0%	2.9%
	External Admin	0.1%	1.6%	0.1%	0.1%	0.3%	0.1%	0.4%	0.1%	0.3%
	Rebate/Services	83.0%	75.2%	87.1%	81.0%	85.1%	83.6%	74.9%	81.7%	84.5%
	Implementation Services	5.6%	11.6%	3.6%	7.2%	4.9%	5.6%	11.7%	7.0%	5.2%
	Marketing	3.0%	2.8%	3.0%	1.5%	2.8%	3.0%	1.5%	2.7%	2.8%
	EM&V	4.9%	3.7%	4.5%	3.5%	4.3%	4.3%	5.4%	4.6%	4.4%
	Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

* Other includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES ENERGY EFFICIENCY PROGRAM - 2023 UTILITY BUDGETS BY ACTIVITY
C&I and Municipal Programs

		Electric Utilities					Gas Utilities			
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	Grand Total
Large Business Energy Solutions	Internal Admin	$ 41,737	$ 36,049	$ 150,198	$ 110,500	$ 338,483	$ 69,739	$ 30,916	$ 100,655	$ 439,139
	External Admin	$ 1,038	$ 11,100	$ 12,703	$ 4,673	$ 29,514	$ 1,721	$ 1,575	$ 3,296	$ 32,810
	Rebate/Services	$ 986,740	$ 353,150	$ 7,723,266	$ 1,091,713	$ 10,154,869	$ 1,699,560	$ 421,963	$ 2,121,524	$ 12,276,392
	Implementation Services	$ 64,615	$ 119,039	$ 599,784	$ 115,523	$ 898,961	$ 114,569	$ 29,782	$ 144,351	$ 1,043,312
	Marketing	$ 35,579	$ 20,974	$ 274,830	$ 26,645	$ 358,027	$ 61,073	$ 10,122	$ 71,195	$ 429,223
	EM&V	$ 56,249	$ 21,335	$ 400,209	$ 45,514	$ 523,307	$ 89,110	$ 24,002	$ 113,111	$ 636,419
	Total	$ 1,185,957	$ 561,647	$ 9,160,989	$ 1,394,568	$ 12,303,161	$ 2,035,773	$ 518,360	$ 2,554,133	$ 14,857,294
Small Business Energy Solutions	Internal Admin	$ 52,070	$ 36,049	$ 164,647	$ 106,681	$ 359,446	$ 59,463	$ 30,634	$ 90,097	$ 449,543
	External Admin	$ 1,295	$ 11,100	$ 13,925	$ 4,525	$ 30,845	$ 1,468	$ 1,575	$ 3,043	$ 33,888
	Rebate/Services	$ 1,231,028	$ 431,628	$ 8,466,247	$ 1,053,838	$ 11,182,742	$ 1,449,127	$ 415,935	$ 1,865,062	$ 13,047,803
	Implementation Services	$ 80,612	$ 124,944	$ 657,484	$ 111,530	$ 974,570	$ 97,687	$ 29,467	$ 127,154	$ 1,101,724
	Marketing	$ 44,387	$ 20,974	$ 301,268	$ 25,724	$ 392,353	$ 52,074	$ 12,187	$ 64,261	$ 456,615
	EM&V	$ 70,174	$ 21,335	$ 438,709	$ 43,941	$ 574,160	$ 75,979	$ 23,783	$ 99,763	$ 673,923
	Total	$ 1,479,566	$ 646,031	$ 10,042,280	$ 1,346,239	$ 13,514,116	$ 1,735,798	$ 513,581	$ 2,249,379	$ 15,763,495
Municipal	Internal Admin	$ 5,924	$ 12,723	$ 23,801	$ 22,791	$ 65,239	$ -	$ -	$ -	$ 65,239
	External Admin	$ 147	$ 5,550	$ 2,013	$ 425	$ 8,135	$ -	$ -	$ -	$ 8,135
	Rebate/Services	$ 140,051	$ 109,993	$ 1,223,870	$ 155,197	$ 1,629,110	$ -	$ -	$ -	$ 1,629,110
	Implementation Services	$ 9,171	$ 24,125	$ 95,045	$ 23,827	$ 152,168	$ -	$ -	$ -	$ 152,168
	Marketing	$ 5,050	$ 4,916	$ 43,551	$ 4,970	$ 58,487	$ -	$ -	$ -	$ 58,487
	EM&V	$ 7,984	$ 6,554	$ 63,419	$ 8,904	$ 86,861	$ -	$ -	$ -	$ 86,861
	Total	$ 168,326	$ 163,861	$ 1,451,699	$ 216,114	$ 2,000,000	$ -	$ -	$ -	$ 2,000,000
Other*	Internal Admin	$ 873	$ -	$ 11,868	$ 17,404	$ 30,145	$ 1,422	$ -	$ 1,422	$ 31,567
	External Admin	$ -	$ -	$ 1,004	$ 384	$ 1,388	$ 35	$ -	$ 35	$ 1,423
	Rebate/Services	$ 22,147	$ 13,279	$ 610,276	$ 175,473	$ 821,175	$ 36,463	$ 12,397	$ 48,860	$ 870,034
	Implementation Services	$ 10,217	$ -	$ 100,817	$ 21,884	$ 132,918	$ 2,336	$ 5,025	$ 7,360	$ 140,278
	Marketing	$ 744	$ 555	$ 12,143	$ 4,446	$ 17,888	$ 1,245	$ 1,088	$ 2,333	$ 20,221
	EM&V	$ 12,678	$ 14,000	$ 17,683	$ 28,451	$ 72,812	$ -	$ -	$ -	$ 72,812
	Total	$ 46,658	$ 27,834	$ 753,791	$ 248,042	$ 1,076,326	$ 41,500	$ 18,509	$ 60,009	$ 1,136,335

* Other includes company-specific programs, education, forward capacity market administration and loan program administration.

NHSAVES ENERGY EFFICIENCY PROGRAM - 2023 UTILITY BUDGETS BY ACTIVITY
C&I and Municipal Program Total and Grand Total (Residential, C&I and Municipal)

		Electric Utilities					Gas Utilities			
		Liberty	NHEC	Eversource	Unitil	Sub-total Electric	Liberty	Unitil	Sub-total Gas	Grand Total
Total C&I and Municipal	Internal Admin	$ 100,603	$ 84,821	$ 350,514	$ 257,376	$ 793,314	$ 130,624	$ 61,550	$ 192,174	$ 985,488
	External Admin	$ 2,481	$ 27,750	$ 29,645	$ 10,007	$ 69,882	$ 3,224	$ 3,150	$ 6,374	$ 76,256
	Rebate/Services	$ 2,379,965	$ 908,050	$ 18,023,659	$ 2,476,221	$ 23,787,895	$ 3,185,150	$ 850,295	$ 4,035,445	$ 27,823,340
	Implementation Services	$ 164,615	$ 268,108	$ 1,453,129	$ 272,764	$ 2,158,616	$ 214,592	$ 64,274	$ 278,865	$ 2,437,481
	Marketing	$ 85,759	$ 47,419	$ 631,792	$ 61,785	$ 826,756	$ 114,392	$ 23,397	$ 137,789	$ 964,545
	EM&V	$ 147,084	$ 63,225	$ 920,021	$ 126,810	$ 1,257,140	$ 165,089	$ 47,785	$ 212,874	$ 1,470,014
	Total	$ 2,880,507	$ 1,399,372	$ 21,408,760	$ 3,204,963	$ 28,893,602	$ 3,813,071	$ 1,050,451	$ 4,863,522	$ 33,757,124
Total C&I and Municipal %	Internal Admin	3.5%	6.1%	1.6%	8.0%	2.7%	3.4%	5.9%	4.0%	2.9%
	External Admin	0.1%	2.0%	0.1%	0.3%	0.2%	0.1%	0.3%	0.1%	0.2%
	Rebate/Services	82.6%	64.9%	84.2%	77.3%	82.3%	83.5%	80.9%	83.0%	82.4%
	Implementation Services	5.7%	19.2%	6.8%	8.5%	7.5%	5.6%	6.1%	5.7%	7.2%
	Marketing	3.0%	3.4%	3.0%	1.9%	2.9%	3.0%	2.2%	2.8%	2.9%
	EM&V	5.1%	4.5%	4.3%	4.0%	4.4%	4.3%	4.5%	4.4%	4.4%
	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Grand Total (Residential, C&I and Municipal)	Internal Admin	$ 185,436	$ 229,245	$ 744,902	$ 481,352	$ 1,640,933	$ 304,642	$ 148,584	$ 453,226	$ 2,094,160
	External Admin	$ 4,550	$ 75,000	$ 63,000	$ 14,772	$ 157,322	$ 7,519	$ 8,151	$ 15,670	$ 172,992
	Rebate/Services	$ 4,388,372	$ 3,067,344	$ 38,303,351	$ 5,189,288	$ 50,948,355	$ 7,429,392	$ 1,916,912	$ 9,346,304	$ 60,294,658
	Implementation Services	$ 299,297	$ 601,337	$ 2,301,493	$ 513,889	$ 3,716,017	$ 500,472	$ 231,586	$ 732,058	$ 4,448,075
	Marketing	$ 158,075	$ 128,159	$ 1,322,974	$ 113,222	$ 1,722,430	$ 266,786	$ 44,425	$ 311,211	$ 2,033,640
	EM&V	$ 264,659	$ 170,879	$ 1,962,044	$ 242,541	$ 2,640,123	$ 384,059	$ 124,832	$ 508,891	$ 3,149,013
	Total	$ 5,300,388	$ 4,271,963	$ 44,697,764	$ 6,555,063	$ 60,825,179	$ 8,892,870	$ 2,474,490	$ 11,367,360	$ 72,192,538
Grand Total % (Residential, C&I and Municipal)	Internal Admin	3.5%	5.4%	1.7%	7.3%	2.7%	3.4%	6.0%	4.0%	2.9%
	External Admin	0.1%	1.8%	0.1%	0.2%	0.3%	0.1%	0.3%	0.1%	0.2%
	Rebate/Services	82.8%	71.8%	85.7%	79.2%	83.8%	83.5%	77.5%	82.2%	83.5%
	Implementation Services	5.6%	14.1%	5.1%	7.8%	6.1%	5.6%	9.4%	6.4%	6.2%
	Marketing	3.0%	3.0%	3.0%	1.7%	2.8%	3.0%	1.8%	2.7%	2.8%
	EM&V	5.0%	4.0%	4.4%	3.7%	4.3%	4.3%	5.0%	4.5%	4.4%
	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

NHSAVES ELECTRIC PROGRAMS - 2022 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	121	4,464,498	71	2,571,023	501	15,921,757	112	2,096,160	805	25,053,438
B/C Ratio[1] / Planned Budget	1.57	$1,176,716	1.70	$1,008,680	1.67	$8,421,306	1.73	$1,204,324	1.67	$11,811,025
/ Lifetime MMBtu Savings		25,830		39,023		354,477		43,427		462,757
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	84	1,175,714	285	6,625,537	1,968	37,380,065	66	3,145,580	2,402	48,326,897
B/C Ratio[1] / Planned Budget	4.33	$617,374	6.22	$988,510	4.24	$6,967,291	2.08	$681,383	4.30	$9,254,558
/ Lifetime MMBtu Savings		95,184		204,672		925,273		36,242		1,261,371
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	96	4,592,326	88	10,702,893	427	17,848,029	158	3,000,000	769	36,143,248
B/C Ratio[1] / Planned Budget	6.31	$170,047	5.75	$538,450	6.11	$1,850,403	3.39	$484,444	5.63	$3,043,343
/ Lifetime MMBtu Savings		19,682		63,301		265,824		38,400		387,206
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	6,887	6,759,130	29,247	21,449,174	64,056	72,301,429	5,499	8,585,998	105,689	109,095,731
B/C Ratio[1] / Planned Budget	1.59	$461,898	2.23	$1,092,955	2.11	$4,109,791	2.09	$524,553	2.09	$6,189,197
/ Lifetime MMBtu Savings		2,161		2,356		59,110		10,212		73,839
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	340	57,620,893	28	28,657,792	265	252,273,753	146	28,144,506	780	366,696,943
B/C Ratio[1] / Planned Budget	3.54	$1,264,081	2.87	$709,668	2.35	$8,790,037	2.05	$1,225,306	2.48	$11,989,092
/ Lifetime MMBtu Savings		-21,273		-5,998		-62,497		-3,654		-93,422
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	564	43,887,351	138	18,312,431	3,157	302,765,968	321	26,503,496	4,181	391,469,245
B/C Ratio[1] / Planned Budget	2.13	$1,532,407	1.50	$823,693	2.52	$9,520,636	1.74	$1,182,612	2.34	$13,059,348
/ Lifetime MMBtu Savings		-13,216		-6,706		-213,105		-3,856		-236,884
Municipal										
Number of Participants / Lifetime kWh Savings	46	3,278,793	16	3,021,453	175	37,283,772	9	3,457,388	246	47,041,405
B/C Ratio[1] / Planned Budget	2.56	$157,337	1.09	$193,726	2.25	$1,375,299	1.18	$217,167	2.04	$1,943,528
/ Lifetime MMBtu Savings		7,159		-1,959		-4,056		-305		840
Educational Programs										
Number of Participants / Planned Budget	0	$71,375	0	$39,046	0	$410,812	0	$62,468	0	$583,701
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	10,256	1,153	0	0	2,083	0	0	3,100	12,339	4,253
/ Planned Budget		$135,666		$20,000		$673,223		$446,694		$1,275,582
/ Lifetime MMBtu Savings		0		0		0		0		0
Smart Start (Eversource)										
Number of Participants / Planned Budget	0	$0	0	$0	0	$30,000	0	$0	0	$30,000
Utility Performance Incentive										
Planned Budget		$307,280		$297,810		$2,316,534		$331,592		$3,253,216
TOTAL PLANNED BUDGET		**$5,894,180**		**$5,712,538**		**$44,465,332**		**$6,360,542**		**$62,432,591**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES ELECTRIC PROGRAMS
SBC[1] and RGGI Funding Allocation
2022 Budget

Program Allocation Summary

Program	RGGI	SBC[1]	TOTAL
HEA[2]			
Liberty	3.31283%	96.68717%	100.00000%
NHEC	3.86281%	96.13719%	100.00000%
Eversource	4.04637%	95.95363%	100.00000%
Unitil	4.23493%	95.76507%	100.00000%
Municipal			
Liberty	100.00000%	0.00000%	100.00000%
NHEC	100.00000%	0.00000%	100.00000%
Eversource	100.00000%	0.00000%	100.00000%
Unitil	100.00000%	0.00000%	100.00000%

A	B	C	D
Utility	**HEA Budget**	**RGGI HEA[3]**	**SBC HEA[4]**
Liberty	$ 1,176,715.56	$ 38,982.59	$ 1,137,732.96
NHEC	$ 1,008,679.93	$ 38,963.38	$ 969,716.55
Eversource	$ 8,421,305.69	$ 340,757.52	$ 8,080,548.17
Unitil	$ 1,204,324.12	$ 51,002.32	$ 1,153,321.80
Total	$ 11,811,025.29	$ 469,705.81	$ 11,341,319.48

Notes:

[1] SBC = System Benefits Charge, Forward Capacity Market and Carryforward/Interest

[2] HEA Allocation
 RGGI HEA = RGGI HEA (C) /Total HEA Funds (B)
 SBC HEA = SBC HEA (D) /Total HEA Funds (B)

[3] 17.0% of Total RGGI Funds including SB 268 funding less RGGI HEA Performance Incentive

[4] SBC HEA = Utility's total HEA program budget (B) less RGGI HEA (C)

NHSAVES ELECTRIC PROGRAMS - 2022 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

(System Benefits Charge, Forward Capacity Market and Interest Funds Only)

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	117	4,316,596	69	2,471,710	481	15,277,503	107	2,007,389	774	24,073,198
B/C Ratio[1] / Planned Budget	1.57	$1,137,733	1.70	$969,717	1.67	$8,080,548	1.73	$1,153,322	1.67	$11,341,319
/ Lifetime MMBtu Savings		24,975		37,515		340,134		41,588		444,212
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	84	1,175,714	285	6,625,537	1,968	37,380,065	66	3,145,580	2,402	48,326,897
B/C Ratio[1] / Planned Budget	4.33	$617,374	6.22	$988,510	4.24	$6,967,291	2.08	$681,383	4.30	$9,254,558
/ Lifetime MMBtu Savings		95,184		204,672		925,273		36,242		1,261,371
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	96	4,592,326	88	10,702,893	427	17,848,029	158	3,000,000	769	36,143,248
B/C Ratio[1] / Planned Budget	6.31	$170,047	5.75	$538,450	6.11	$1,850,403	3.39	$484,444	5.63	$3,043,343
/ Lifetime MMBtu Savings		19,682		63,301		265,824		38,400		387,206
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	6,887	6,759,130	29,247	21,449,174	64,056	72,301,429	5,499	8,585,998	105,689	109,095,731
B/C Ratio[1] / Planned Budget	1.59	$461,898	2.23	$1,092,955	2.11	$4,109,791	2.09	$524,553	2.09	$6,189,197
/ Lifetime MMBtu Savings		2,161		2,356		59,110		10,212		73,839
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	340	57,620,893	28	28,657,792	265	252,273,753	146	28,144,506	780	366,696,943
B/C Ratio[1] / Planned Budget	3.54	$1,264,081	2.87	$709,668	2.35	$8,790,037	2.05	$1,225,306	2.48	$11,989,092
/ Lifetime MMBtu Savings		-21,273		-5,998		-62,497		-3,654		-93,422
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	564	43,887,351	138	18,312,431	3,157	302,765,968	321	26,503,496	4,181	391,469,245
B/C Ratio[1] / Planned Budget	2.13	$1,532,407	1.50	$823,693	2.52	$9,520,636	1.74	$1,182,612	2.34	$13,059,348
/ Lifetime MMBtu Savings		-13,216		-6,706		-213,105		-3,856		-236,884
Municipal										
Number of Participants / Lifetime kWh Savings	0	0	0	0	0	0	0	0	0	0
B/C Ratio[1] / Planned Budget	2.56	$0	1.09	$0	2.25	$0	1.18	$0	2.04	$0
/ Lifetime MMBtu Savings		0		0		0		0		0
Educational Programs										
Number of Participants / Planned Budget	0	$71,375	0	$39,046	0	$410,812	0	$62,468	0	$583,701
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	10,256	1,153	0	0	2,083	0	0	3,100	12,339	4,253
/ Planned Budget		$135,666		$20,000		$673,223		$446,694		$1,275,582
/ Lifetime MMBtu Savings		0		0		0		0		0
Smart Start (Eversource/NHEC)										
Number of Participants / Planned Budget	0	$0	0	$0	0	$30,000	0	$0	0	$30,000
Utility Performance Incentive										
Planned Budget		$296,482		$285,012		$2,222,151		$316,843		$3,120,488
TOTAL PLANNED BUDGET		**$5,687,063**		**$5,467,050**		**$42,654,892**		**$6,077,624**		**$59,886,629**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES ELECTRIC PROGRAMS - 2022 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

(Energy Efficiency Fund Only - Regional Greenhouse Gas Initiative)

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	4	147,901	3	99,314	20	644,254	5	88,771	32	980,240
B/C Ratio[1] / Planned Budget	1.57	$38,983	1.70	$38,963	1.67	$340,758	1.73	$51,002	1.67	$469,706
/ Lifetime MMBtu Savings		856		1,507		14,343		1,839		18,546
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Municipal										
Number of Participants / Lifetime kWh Savings	46	3,278,793	16	3,021,453	175	37,283,772	9	3,457,388	246	47,041,405
B/C Ratio[1] / Planned Budget	2.56	$157,337	1.09	$193,726	2.25	$1,375,299	1.18	$217,167	2.04	$1,943,528
/ Lifetime MMBtu Savings		7,159		-1,959		-4,056		-305		840
Educational Programs										
Number of Participants / Planned Budget	-	-	-	-	-	-	-	-	-	-
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
/ Planned Budget		-		-		-		-		-
/ Lifetime MMBtu Savings		-		-		-		-		-
Smart Start (Eversource/NHEC)										
Number of Participants / Planned Budget	-	-	-	-	-	-	-	-	-	-
Utility Performance Incentive										
Planned Budget		$10,798		$12,798		$94,383		$14,749		$132,728
TOTAL PLANNED BUDGET		**$207,117**		**$245,487**		**$1,810,439**		**$282,919**		**$2,545,962**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES GAS PROGRAMS - 2022 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets and Lifetime MMBtu Savings

	Liberty		Unitil		Total	
Home Energy Assistance						
Number of Units / Lifetime MMBtu Savings	299	126,196	56	57,041	355	183,237
B/C Ratio[1] / Planned Budget	1.96	$1,698,829	1.03	$556,859	1.73	$2,255,688
Home Performance w/ENERGY STAR						
Number of Participants / Lifetime MMBtu Savings	491	337,127	75	38,166	566	375,293
B/C Ratio[1] / Planned Budget	2.73	$1,206,945	1.14	$332,866	2.39	$1,539,811
ENERGY STAR Homes						
Number of Homes / Lifetime MMBtu Savings	249	134,653	106	57,950	355	192,603
B/C Ratio[1] / Planned Budget	2.03	$637,758	1.83	$298,548	1.97	$936,307
ENERGY STAR Products						
Number of Participants / Lifetime MMBtu Savings	2,710	319,442	182	34,438	2,892	353,879
B/C Ratio[1] / Planned Budget	2.41	$1,246,390	1.95	$164,571	2.36	$1,410,961
/ Lifetime kWh Savings		476,718		132,391		609,109
Large Business Energy Solutions						
Number of Participants / Lifetime MMBtu Savings	438	712,616	118	325,856	556	1,038,472
B/C Ratio[1] / Planned Budget	3.34	$1,888,284	3.88	$681,275	3.48	$2,569,559
Small Business Energy Solutions						
Number of Participants / Lifetime MMBtu Savings	2,294	402,181	168	197,483	2,462	599,664
B/C Ratio[1] / Planned Budget	2.75	$1,544,864	2.66	$675,372	2.72	$2,220,236
Education						
/ Planned Budget		$108,575		$34,114		$142,689
Company Specific Programs						
Number of Participants / Lifetime MMBtu Savings	30,000	17,325	11,200	5,847	41,200	23,173
/ Planned Budget		$162,500		$40,694		$203,194
Utility Performance Incentive						
Planned Budget		$467,178		$153,136		$620,314
Total Program Expenses		**$8,961,323**		**$2,937,434**		**$11,898,757**

NHSAVES ELECTRIC PROGRAMS - 2023 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	102	4,108,473	71	2,253,423	496	15,782,505	128	2,158,988	798	24,303,389
B/C Ratio[1] / Planned Budget	1.59	$1,057,265	1.80	$847,867	1.62	$8,906,891	1.92	$1,311,013	1.66	$12,123,036
/ Lifetime MMBtu Savings		21,804		32,230		337,100		49,629		440,762
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	72	1,011,848	225	3,876,577	1,987	38,298,277	68	3,163,638	2,352	46,350,340
B/C Ratio[1] / Planned Budget	4.41	$559,963	6.06	$663,959	4.01	$7,538,561	2.21	$703,703	4.05	$9,466,186
/ Lifetime MMBtu Savings		81,918		125,642		876,718		37,547		1,121,825
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	142	6,448,960	66	8,019,838	431	18,046,867	166	2,835,000	806	35,350,664
B/C Ratio[1] / Planned Budget	6.78	$210,500	5.62	$434,692	5.64	$1,998,336	3.67	$500,678	5.40	$3,144,206
/ Lifetime MMBtu Savings		23,116		47,432		251,677		41,550		363,775
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	4,169	5,830,248	15,931	16,029,066	62,966	74,896,935	5,856	8,024,038	88,922	104,780,286
B/C Ratio[1] / Planned Budget	1.67	$424,185	2.16	$896,519	2.17	$4,463,873	2.10	$541,658	2.13	$6,326,235
/ Lifetime MMBtu Savings		3,027		6,194		69,564		10,800		89,585
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	299	49,812,501	21	20,122,639	259	236,358,464	128	29,284,298	707	335,577,902
B/C Ratio[1] / Planned Budget	3.47	$1,185,957	2.72	$561,647	2.22	$9,160,989	1.48	$1,394,568	2.28	$12,303,161
/ Lifetime MMBtu Savings		-17,865		-3,924		-57,230		-2,890		-81,909
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	520	39,098,924	107	13,389,465	3,101	279,455,051	327	28,951,304	4,055	360,894,744
B/C Ratio[1] / Planned Budget	2.08	$1,479,566	1.48	$646,031	2.32	$10,042,280	1.65	$1,346,239	2.19	$13,514,116
/ Lifetime MMBtu Savings		-11,892		-4,874		-196,634		-4,236		-217,636
Municipal										
Number of Participants / Lifetime kWh Savings	47	3,311,252	13	2,259,189	173	35,575,553	7	3,614,801	241	44,760,795
B/C Ratio[1] / Planned Budget	2.56	$168,326	1.01	$163,861	2.15	$1,451,699	1.15	$216,114	1.98	$2,000,000
/ Lifetime MMBtu Savings		7,135		-1,464		-3,535		-288		1,848
Educational Programs										
Number of Participants / Planned Budget	0	$70,900	0	$37,388	0	$400,377	0	$58,839	0	$567,504
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	10,256	1,914	0	0	2,204	0	0	3,116	12,460	5,030
/ Planned Budget		$143,726		$20,000		$704,758		$482,252		$1,350,736
/ Lifetime MMBtu Savings		0		0		0		0		0
Smart Start (Eversource/NHEC)										
Number of Participants / Planned Budget	0	$0	0	$0	0	$30,000	0	$0	0	$30,000
Utility Performance Incentive										
Planned Budget		$291,521		$234,958		$2,456,727		$360,528		$3,343,735
TOTAL PLANNED BUDGET		**$5,591,910**		**$4,506,921**		**$47,154,491**		**$6,915,592**		**$64,168,914**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES ELECTRIC PROGRAMS
SBC[1] and RGGI Funding Allocation
2023 Budget

Program Allocation Summary

Program	RGGI	SBC[1]	TOTAL
HEA[2]			
Liberty	3.64772%	96.35228%	100.00000%
NHEC	3.86945%	96.13055%	100.00000%
Eversource	3.70048%	96.29952%	100.00000%
Unitil	3.77685%	96.22315%	100.00000%
Municipal			
Liberty	100.00000%	0.00000%	100.00000%
NHEC	100.00000%	0.00000%	100.00000%
Eversource	100.00000%	0.00000%	100.00000%
Unitil	100.00000%	0.00000%	100.00000%

A	B	C	D
Utility	**HEA Budget**	**RGGI HEA[3]**	**SBC HEA[4]**
Liberty	$ 1,057,265.31	$ 38,566.11	$ 1,018,699.20
NHEC	$ 847,866.52	$ 32,807.77	$ 815,058.75
Eversource	$ 8,906,891.40	$ 329,597.93	$ 8,577,293.47
Unitil	$ 1,311,012.84	$ 49,514.98	$ 1,261,497.86
Total	$ 12,123,036.07	$ 450,486.79	$ 11,672,549.29

Notes:

[1] SBC = System Benefits Charge, Forward Capacity Market and Carryforward/Interest

[2] HEA Allocation

RGGI HEA = RGGI HEA (C) /Total HEA Funds (B)

SBC HEA = SBC HEA (D) /Total HEA Funds (B)

[3] 17.0% of Total RGGI Funds including SB 268 funding less RGGI HEA Performance Incentive

[4] SBC HEA = Utility's total HEA program budget (B) less RGGI HEA (C)

NHSAVES ELECTRIC PROGRAMS - 2023 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

(System Benefits Charge, Forward Capacity Market and Interest Funds Only)

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	98	3,958,607	69	2,166,228	478	15,198,476	123	2,077,446	768	23,400,758
B/C Ratio[1] / Planned Budget	1.59	$1,018,699	1.80	$815,059	1.62	$8,577,293	1.92	$1,261,498	1.66	$11,672,549
/ Lifetime MMBtu Savings		21,008		30,983		324,625		47,754		424,371
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	72	1,011,848	225	3,876,577	1,987	38,298,277	68	3,163,638	2,352	46,350,340
B/C Ratio[1] / Planned Budget	4.41	$559,963	6.06	$663,959	4.01	$7,538,561	2.21	$703,703	4.05	$9,466,186
/ Lifetime MMBtu Savings		81,918		125,642		876,718		37,547		1,121,825
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	142	6,448,960	66	8,019,838	431	18,046,867	166	2,835,000	806	35,350,664
B/C Ratio[1] / Planned Budget	6.78	$210,500	5.62	$434,692	5.64	$1,998,336	3.67	$500,678	5.40	$3,144,206
/ Lifetime MMBtu Savings		23,116		47,432		251,677		41,550		363,775
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	4,169	5,830,248	15,931	16,029,066	62,966	74,896,935	5,856	8,024,038	88,922	104,780,286
B/C Ratio[1] / Planned Budget	1.67	$424,185	2.16	$896,519	2.17	$4,463,873	2.10	$541,658	2.13	$6,326,235
/ Lifetime MMBtu Savings		3,027		6,194		69,564		10,800		89,585
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	299	49,812,501	21	20,122,639	259	236,358,464	128	29,284,298	707	335,577,902
B/C Ratio[1] / Planned Budget	3.47	$1,185,957	2.72	$561,647	2.22	$9,160,989	1.48	$1,394,568	2.28	$12,303,161
/ Lifetime MMBtu Savings		-17,865		-3,924		-57,230		-2,890		-81,909
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	520	39,098,924	107	13,389,465	3,101	279,455,051	327	28,951,304	4,055	360,894,744
B/C Ratio[1] / Planned Budget	2.08	$1,479,566	1.48	$646,031	2.32	$10,042,280	1.65	$1,346,239	2.19	$13,514,116
/ Lifetime MMBtu Savings		-11,892		-4,874		-196,634		-4,236		-217,636
Municipal										
Number of Participants / Lifetime kWh Savings	0	0	0	0	0	0	0	0	0	0
B/C Ratio[1] / Planned Budget	2.56	$0	1.01	$0	2.15	$0	1.15	$0	1.98	$0
/ Lifetime MMBtu Savings		0		0		0		0		0
Educational Programs										
Number of Participants / Planned Budget	0	$70,900	0	$37,388	0	$400,377	0	$58,839	0	$567,504
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	10,256	1,914	0	0	2,204	0	0	3,116	12,460	5,030
/ Planned Budget		$143,726		$20,000		$704,758		$482,252		$1,350,736
/ Lifetime MMBtu Savings		0		0		0		0		0
Smart Start (Eversource/NHEC)										
Number of Participants / Planned Budget	0	$0	0	$0	0	$30,000	0	$0	0	$30,000
Utility Performance Incentive										
Planned Budget		$280,142		$224,141		$2,358,756		$345,919		$3,208,958
TOTAL PLANNED BUDGET		**$5,373,638**		**$4,299,436**		**$45,275,223**		**$6,635,354**		**$61,583,651**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES ELECTRIC PROGRAMS - 2023 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets, Lifetime kWh and MMBtu Savings

(Energy Efficiency Fund Only - Regional Greenhouse Gas Initiative)

	Liberty		NHEC		Eversource		Unitil		Total	
Home Energy Assistance										
Number of Units / Lifetime kWh Savings	4	149,866	3	87,195	18	584,029	5	81,542	30	902,631
B/C Ratio[1] / Planned Budget	1.59	$38,566	1.80	$32,808	1.62	$329,598	1.92	$49,515	1.66	$450,487
/ Lifetime MMBtu Savings		795		1,247		12,474		1,874		16,391
Home Performance w/ENERGY STAR										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
ENERGY STAR Homes										
Number of Homes / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
ENERGY STAR Products										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Large Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
B/C Ratio[1] / Planned Budget	-	-	-	-	-	-	-	-	-	-
/ Lifetime MMBtu Savings		-		-		-		-		-
Municipal										
Number of Participants / Lifetime kWh Savings	47	3,311,252	13	2,259,189	173	35,575,553	7	3,614,801	241	44,760,795
B/C Ratio[1] / Planned Budget	2.56	$168,326	1.01	$163,861	2.15	$1,451,699	1.15	$216,114	1.98	$2,000,000
/ Lifetime MMBtu Savings		7,135		-1,464		-3,535		-288		1,848
Educational Programs										
Number of Participants / Planned Budget	-	-	-	-	-	-	-	-	-	-
Company Specific Programs / FCM Expenses										
Number of Participants / Lifetime kWh Savings	-	-	-	-	-	-	-	-	-	-
/ Planned Budget		-		-		-		-		-
/ Lifetime MMBtu Savings		-		-		-		-		-
Smart Start (Eversource/NHEC)										
Number of Participants / Planned Budget	-	-	-	-	-	-	-	-	-	-
Utility Performance Incentive										
Planned Budget		$11,379		$10,817		$97,971		$14,610		$134,777
TOTAL PLANNED BUDGET		**$218,272**		**$207,485**		**$1,879,268**		**$280,238**		**$2,585,263**

Note: (1) B/C Ratios based on Utility Costs set to 2021 dollars

NHSAVES GAS PROGRAMS - 2023 UTILITY GOALS BY PROGRAM
Total Customers Served, Program Budgets and Lifetime MMBtu Savings

	Liberty		Unitil		Total	
Home Energy Assistance						
Number of Units / Lifetime MMBtu Savings	308	130,040	56	47,568	364	177,607
B/C Ratio[1] / Planned Budget	2.10	$1,778,574	1.01	$494,897	1.87	$2,273,471
Home Performance w/ENERGY STAR						
Number of Participants / Lifetime MMBtu Savings	416	327,697	6	38,255	422	365,951
B/C Ratio[1] / Planned Budget	2.88	$1,191,709	1.11	$358,565	2.47	$1,550,274
ENERGY STAR Homes						
Number of Homes / Lifetime MMBtu Savings	239	132,054	106	63,425	345	195,479
B/C Ratio[1] / Planned Budget	1.64	$645,320	1.93	$331,599	1.74	$976,919
ENERGY STAR Products						
Number of Participants / Lifetime MMBtu Savings	2,627	293,273	182	32,492	2,809	325,765
B/C Ratio[1] / Planned Budget	2.35	$1,211,736	1.83	$173,660	2.29	$1,385,396
/ Lifetime kWh Savings		357,628		132,391		490,018
Large Business Energy Solutions						
Number of Participants / Lifetime MMBtu Savings	444	751,638	108	220,366	552	972,004
B/C Ratio[1] / Planned Budget	3.48	$2,035,773	3.83	$518,360	3.55	$2,554,133
Small Business Energy Solutions						
Number of Participants / Lifetime MMBtu Savings	2,495	411,783	140	156,348	2,635	568,131
B/C Ratio[1] / Planned Budget	2.66	$1,735,798	3.10	$513,581	2.76	$2,249,379
Education						
/ Planned Budget		$118,800		$39,162		$157,962
Company Specific Programs						
Number of Participants / Lifetime MMBtu Savings	30,000	28,410	11,200	5,847	41,200	34,257
/ Planned Budget		$175,160		$44,667		$219,827
Utility Performance Incentive						
Planned Budget		$489,108		$136,097		$625,205
Total Program Expenses		**$9,381,978**		**$2,610,587**		**$11,992,565**

Program Cost-Effectiveness - 2022 Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.67	1.67	14,058.7	14,058.7	8,421.3	-	1,087.3	15,921.8	162.7	268.2	501	16,741.2	354,477.1
A1 - Energy Star Homes	6.68	6.11	14,000.6	11,313.2	1,850.4	245.9	826.2	17,848.0	217.9	31.1	427	11,103.0	265,823.7
A2 - Home Performance with Energy Star	4.18	4.24	36,464.4	29,526.1	6,967.3	1,754.3	1,925.8	37,380.1	345.4	452.6	1,968	41,032.5	925,273.0
A3 - Energy Star Products	1.93	2.11	10,654.5	8,687.3	4,109.8	1,416.2	7,147.2	72,301.4	1,435.9	1,064.5	64,056	975.5	59,109.6
A5 - Residential Active Demand Response	-	-	-	-	123.2	-	-	-	-	-	2,055	-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	48.0	-	-	-	-	-	-	-	-
A6c - Res Education	-	-	-	-	209.6	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.99**	**2.93**	**75,178.3**	**63,585.4**	**21,729.6**	**3,416.4**	**10,986.4**	**143,451.3**	**2,161.9**	**1,816.5**	**69,007**	**69,852.2**	**1,604,683.4**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.44	2.35	22,763.2	20,686.4	8,790.0	6,964.7	20,718.7	252,273.8	2,312.6	2,733.0	265	(5,792.8)	(62,497.2)
C2 - Small Business Energy Solutions	1.77	2.52	26,436.8	24,008.3	9,520.6	5,447.8	26,477.2	302,766.0	3,406.1	3,844.9	3,157	(19,858.2)	(213,105.3)
C3 - Municipal Energy Solutions	1.51	2.25	3,405.1	3,095.2	1,375.3	886.4	2,878.0	37,283.8	253.6	292.3	175	(480.9)	(4,056.0)
C5 - C&I Active Demand Response	-	-	-	-	378.7	-	-	-	-	-	28	-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	108.0	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	201.2	-	-	-	-	-	-	-	-
C6d - C&I Customer Partnerships	-	-	-	-	15.3	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.56**	**2.34**	**52,605.1**	**47,789.9**	**20,389.2**	**13,299.0**	**50,073.9**	**592,323.5**	**5,972.4**	**6,870.1**	**3,625**	**(26,132.0)**	**(279,658.6)**
C6e - Smart Start	-	-	-	-	30.0	-	-	-	-	-		-	-
Total	**2.17**	**2.64**	**127,783.4**	**111,375.3**	**42,148.8**	**16,715.4**	**61,060.4**	**735,774.8**	**8,134.3**	**8,686.6**	**72,632**	**43,720.2**	**1,325,024.8**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual kWh Savings	61,060,351	82.7%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	12,813,137	17.3%	
	73,873,489	100.0%	

Lifetime kWh Savings	735,774,773	65.5%	**kWh > 65%**
Lifetime MMBTU Savings (in kWh)	388,326,459	34.5%	
	1,124,101,232	100.0%	

Annual Net Savings as a % of 2019 Sales	0.79%

Spending per Customer	Low-Income	$ 354.34
	Residential	$ 31.82
	C&I	$ 261.95

Present Value Benefits - 2022 PLAN

	Total Benefits ($000)[1] Granite State Test	Resource Benefits ($000) – Electric – CAPACITY: Summer Generation	Winter Generation	Transmission	Distribution	Reliability	ENERGY: Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Non-Electric: Other Fuels	Water Benefit	Total Resource Benefits	Non-Resource Benefits ($000): Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	Environmental Benefits ($000)[3]
Residential Programs																			
B1 - Home Energy Assistance	**$ 14,059**	$ 231	$ -	$ 374	$ 386	$ -	$ 223	$ 232	$ 218	$ 188	$ 52	**$ 1,904**	$ 8,892	$ 20	**$ 10,817**	$ 640	$ 2,602	**$ 3,242**	**$ 601**
A1 - Energy Star Homes	**$ 11,313**	$ 23	$ -	$ 38	$ 39	$ -	$ 471	$ 564	$ 32	$ 26	$ 57	**$ 1,250**	$ 9,499	$ 84	**$ 10,834**	$ 479	$ 2,687	**$ 3,167**	**$ 571**
A2 - Home Performance with Energy Star	**$ 29,526**	$ 479	$ -	$ 762	$ 787	$ -	$ 590	$ 706	$ 417	$ 352	$ 100	**$ 4,193**	$ 23,560	$ 10	**$ 27,764**	$ 1,763	$ 6,938	**$ 8,701**	**$ 1,221**
A3 - Energy Star Products	**$ 8,687**	$ 462	$ -	$ 822	$ 848	$ -	$ 1,566	$ 1,635	$ 581	$ 480	$ 339	**$ 6,732**	$ 1,137	$ 731	**$ 8,600**	$ 88	$ 1,967	**$ 2,055**	**$ 3,219**
Sub-Total Residential	**$ 63,862**	**$ 1,205**	**$ -**	**$ 2,124**	**$ 2,192**	**$ -**	**$ 2,851**	**$ 3,136**	**$ 1,249**	**$ 1,046**	**$ 553**	**$ 14,356**	**$ 43,088**	**$ 846**	**$ 58,291**	**$ 2,969**	**$ 14,195**	**$ 17,164**	**$ 5,613**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 20,686**	$ 1,544	$ -	$ 2,709	$ 2,796	$ -	$ 4,965	$ 2,854	$ 3,601	$ 2,182	$ 1,151	**$ 21,801**	$ (1,033)	$ -	**$ 20,768**	$ (82)	$ 2,077	**$ 1,995**	**$ 11,003**
C2 - Small Business Energy Solutions	**$ 24,008**	$ 2,051	$ -	$ 3,617	$ 3,733	$ -	$ 5,880	$ 3,723	$ 4,662	$ 2,638	$ 1,506	**$ 27,810**	$ (3,525)	$ -	**$ 24,285**	$ (277)	$ 2,428	**$ 2,152**	**$ 14,157**
C3 - Municipal Energy Solutions	**$ 3,095**	$ 172	$ -	$ 301	$ 311	$ -	$ 866	$ 497	$ 485	$ 274	$ 172	**$ 3,080**	$ 20	$ -	**$ 3,100**	$ (4)	$ 310	**$ 306**	**$ 1,640**
Sub-Total Commercial & Industrial	**$ 49,079**	**$ 3,807**	**$ -**	**$ 7,234**	**$ 7,466**	**$ -**	**$ 11,711**	**$ 7,074**	**$ 8,748**	**$ 5,094**	**$ 2,847**	**$ 53,980**	**$ (4,538)**	**$ -**	**$ 49,442**	**$ (362)**	**$ 4,815**	**$ 4,453**	**$ 26,800**
Total	**$ 112,941**	**$ 5,012**	**$ -**	**$ 9,358**	**$ 9,658**	**$ -**	**$ 14,562**	**$ 10,210**	**$ 9,997**	**$ 6,140**	**$ 3,400**	**$ 68,337**	**$ 38,550**	**$ 846**	**$ 107,733**	**$ 2,607**	**$ 19,010**	**$ 21,617**	**$ 32,413**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2022

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	735,774,773	*551,831,080*		-	1.925%	-	$ 810,787	*$ 1,013,484*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	61,060,351	*45,795,264*		-	0.550%	-	$ 231,653	*$ 289,567*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	8,687	*5,646*		-	0.660%	-	$ 277,984	*$ 347,480*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	8,134	*5,287*		-	0.440%	-	$ 185,323	*$ 231,653*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 107,732,524			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 42,118,798			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 65,613,726	*$ 49,210,294*	$ -	-	1.925%	-	$ 810,787	*$ 1,013,484*	$ -	Line 5 minus line 6
9	Total					5.500%	-	$ 2,316,534	*$ 2,895,667*	$ -	

		Granite State Test		Source
		Planned	Actual	
10	Total Benefits	$ 111,375,279		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 2,316,534	$ -	from row 9 above
12	Total Utility Costs	$ 42,118,798	$ -	from row 7 above
13	**Portfolio GST BCR**	**2.51**	**-**	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

[2] Net of Smart Start

Program Cost-Effectiveness - 2023 Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	**Granite State Test**	**Total Resource Cost Test**	**Granite State Test**	**Utility Costs ($000 - 2022$)[2]**	**Customer Costs ($000 - 2022$)[2]**	**Annual Net MWh Savings**	**Lifetime Net MWh Savings**	**Winter kW Savings**	**Summer kW Savings**	**Number of Customers Served**	**Annual Net MMBtu Savings**	**Lifetime Net MMBtu Savings**
Residential Programs													
B1 - Home Energy Assistance	1.62	1.62	14,009.7	14,009.7	8,626.5	-	1,077.5	15,782.5	161.4	265.7	496	15,961.9	337,099.6
A1 - Energy Star Homes	6.31	5.64	13,492.3	10,909.6	1,935.4	202.1	835.3	18,046.9	182.0	28.7	431	10,512.4	251,676.5
A2 - Home Performance with Energy Star	3.97	4.01	36,177.2	29,305.8	7,301.3	1,800.9	1,950.1	38,298.3	350.6	457.0	1,987	39,090.2	876,718.4
A3 - Energy Star Products	2.00	2.17	11,513.9	9,391.0	4,323.4	1,432.6	7,150.0	74,896.9	1,438.7	1,066.1	62,966	2,177.8	69,564.2
A5 - Residential Active Demand Response	-	-	-	-	127.6	-	-	-	-	-	2,177	-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	46.5	-	-	-	-	-	-	-	-
A6c - Res Education	-	-	-	-	195.3	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.89**	**2.82**	**75,193.1**	**63,616.2**	**22,555.9**	**3,435.6**	**11,012.9**	**147,024.6**	**2,132.6**	**1,817.5**	**68,057**	**67,742.3**	**1,535,058.7**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.42	2.22	21,648.3	19,672.9	8,872.6	6,383.4	19,355.4	236,358.5	2,121.5	2,512.3	259	(5,301.0)	(57,230.3)
C2 - Small Business Energy Solutions	1.73	2.32	24,851.6	22,569.1	9,726.2	4,672.3	24,371.9	279,455.1	3,121.0	3,529.3	3,101	(18,320.4)	(196,634.1)
C3 - Municipal Energy Solutions	1.49	2.15	3,326.2	3,023.4	1,406.0	823.9	2,735.5	35,575.6	238.6	276.7	173	(427.5)	(3,534.8)
C5 - C&I Active Demand Response	-	-	-	-	392.0	-	-	-	-	-	28	-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	104.6	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	192.5	-	-	-	-	-	-	-	-
C6d - C&I Customer Partnerships	-	-	-	-	11.9	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.53**	**2.19**	**49,826.1**	**45,265.4**	**20,705.8**	**11,879.6**	**46,462.8**	**551,389.1**	**5,481.1**	**6,318.2**	**3,561**	**(24,048.9)**	**(257,399.1)**
C6e - Smart Start	-	-	-	-	29.1	-	-	-	-	-		-	-
Total	**2.13**	**2.52**	**125,019.2**	**108,881.6**	**43,290.8**	**15,315.2**	**57,475.7**	**698,413.7**	**7,613.7**	**8,135.7**	**71,618**	**43,693.5**	**1,277,659.6**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2023.

Annual kWh Savings	57,475,695	81.8%	**kWh > 65%**	**Lifetime** kWh Savings	698,413,652	65.1%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	12,805,287	18.2%		**Lifetime** MMBTU Savings (in kWh)	374,445,078	34.9%	
	70,280,982	100.0%			**1,072,858,730**	100.0%	

Annual Net Savings as a % of 2019 Sales	0.75%

Spending per Customer	Low-Income	$	362.98
	Residential	$	33.30
	C&I	$	266.02

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environmental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 14,010**	$ 235	$ -	$ 378	$ 390	$ -	$ 225	$ 236	$ 222	$ 192	$ 53	**$ 1,931**	$ 8,769	$ 21	**$ 10,721**	$ 659	$ 2,630	**$ 3,289**	**$ 571**
A1 - Energy Star Homes	**$ 10,910**	$ 21	$ -	$ 36	$ 37	$ -	$ 391	$ 472	$ 30	$ 24	$ 50	**$ 1,062**	$ 9,269	$ 87	**$ 10,418**	$ 492	$ 2,583	**$ 3,075**	**$ 450**
A2 - Home Performance with Energy Star	**$ 29,306**	$ 499	$ -	$ 785	$ 810	$ -	$ 625	$ 750	$ 433	$ 366	$ 107	**$ 4,376**	$ 23,110	$ 11	**$ 27,496**	$ 1,810	$ 6,871	**$ 8,681**	**$ 1,204**
A3 - Energy Star Products	**$ 9,391**	$ 485	$ -	$ 863	$ 891	$ -	$ 1,645	$ 1,746	$ 609	$ 506	$ 348	**$ 7,093**	$ 1,399	$ 790	**$ 9,282**	$ 109	$ 2,123	**$ 2,232**	**$ 3,152**
Sub-Total Residential	**$ 63,915**	**$ 1,252**	**$ -**	**$ 2,201**	**$ 2,271**	**$ -**	**$ 2,886**	**$ 3,204**	**$ 1,294**	**$ 1,088**	**$ 563**	**$ 14,760**	**$ 42,547**	**$ 908**	**$ 58,216**	**$ 3,069**	**$ 14,207**	**$ 17,276**	**$ 5,376**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 19,673**	$ 1,448	$ -	$ 2,543	$ 2,624	$ -	$ 4,741	$ 2,732	$ 3,446	$ 2,102	$ 1,096	**$ 20,733**	$ (978)	$ -	**$ 19,754**	$ (82)	$ 1,975	**$ 1,894**	**$ 9,878**
C2 - Small Business Energy Solutions	**$ 22,569**	$ 1,925	$ -	$ 3,392	$ 3,501	$ -	$ 5,526	$ 3,519	$ 4,404	$ 2,503	$ 1,417	**$ 26,188**	$ (3,363)	$ 23	**$ 22,848**	$ (278)	$ 2,282	**$ 2,004**	**$ 12,562**
C3 - Municipal Energy Solutions	**$ 3,023**	$ 167	$ -	$ 292	$ 301	$ -	$ 848	$ 486	$ 472	$ 267	$ 167	**$ 3,001**	$ 26	$ -	**$ 3,028**	$ (4)	$ 303	**$ 299**	**$ 1,499**
Sub-Total Commercial & Industrial	**$ 46,583**	**$ 3,582**	**$ -**	**$ 6,846**	**$ 7,065**	**$ -**	**$ 11,116**	**$ 6,737**	**$ 8,321**	**$ 4,872**	**$ 2,699**	**$ 51,239**	**$ (4,315)**	**$ 23**	**$ 46,947**	**$ (364)**	**$ 4,561**	**$ 4,197**	**$ 23,939**
Total	**$ 110,498**	**$ 4,834**	**$ -**	**$ 9,047**	**$ 9,337**	**$ -**	**$ 14,002**	**$ 9,942**	**$ 9,616**	**$ 5,960**	**$ 3,262**	**$ 66,000**	**$ 38,232**	**$ 931**	**$ 105,162**	**$ 2,705**	**$ 18,768**	**$ 21,473**	**$ 29,315**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2023

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	698,413,652	*523,810,239*		-	1.925%	-	$ 832,789	*$ 1,040,986*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	57,475,695	*43,106,771*		-	0.550%	-	$ 237,940	*$ 297,425*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	8,136	*5,288*		-	0.660%	-	$ 285,528	*$ 356,909*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	7,614	*4,949*		-	0.440%	-	$ 190,352	*$ 237,940*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 105,162,427			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 43,261,757			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 61,900,669	*$ 46,425,502*	$ -	-	1.925%	-	$ 832,789	*$ 1,040,986*	$ -	Line 5 minus line 6
9	Total					5.500%	-	$ 2,379,397	*$ 2,974,246*	$ -	

		Granite State Test		
		Planned	Actual	Source
10	Total Benefits	$ -		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 2,379,397	$ -	from row 9 above
12	Total Utility Costs	$ 43,261,757	$ -	from row 7 above
13	**Portfolio GST BCR**	**0.00**	**-**	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $2,456,727.04.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

[2] Net of Smart Start

ADR Program Cost-Effectiveness

2022

	Benefit/Cost Ratios		Benefits ($000)								
	Granite State Test	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Utility Costs ($000 - 2022$)[1]	Customer Costs ($000 - 2022$)[1]	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served
Residential Programs											
A5 - Residential Active Demand Response	2.24	2.24	276.4	276.4	123.2	-	(1.1)	(1.1)	-	1,508.5	2,055
Sub-Total Residential	**2.24**	**2.24**	**276.4**	**276.4**	**123.2**	**-**	**(1.1)**	**(1.1)**	**-**	**1,508.5**	**2,055**
Commercial, Industrial & Municipal											
C5 - C&I Active Demand Response	3.41	3.41	1,289.6	1,289.6	378.7	-	-	-	-	7,113.8	28
Sub-Total Commercial & Industrial	**3.41**	**3.41**	**1,289.6**	**1,289.6**	**378.7**	**-**	**-**	**-**	**-**	**7,113.8**	**28**
Total	**3.12**	**3.12**	**1,566.0**	**1,566.0**	**501.9**	**-**	**(1.1)**	**(1.1)**	**-**	**8,622.3**	**2,083**

(1) Utility and Customer Costs in 2022 Dollars.

2023

	Benefit/Cost Ratios		Benefits ($000)								
	Granite State Test	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Utility Costs ($000 - 2022$)[1]	Customer Costs ($000 - 2022$)[1]	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served
Residential Programs											
A5 - Residential Active Demand Response	2.34	2.34	298.8	298.8	127.6	-	(1.1)	(1.1)	-	1,596.7	2,177
Sub-Total Residential	**2.34**	**2.34**	**298.8**	**298.8**	**127.6**	**-**	**(1.1)**	**(1.1)**	**-**	**1,596.7**	**2,177**
Commercial, Industrial & Municipal											
C5 - C&I Active Demand Response	3.36	3.36	1,317.4	1,317.4	392.0	-	-	-	-	7,113.7	28
Sub-Total Commercial & Industrial	**3.36**	**3.36**	**1,317.4**	**1,317.4**	**392.0**	**-**	**-**	**-**	**-**	**7,113.7**	**28**
Total	**3.11**	**3.11**	**1,616.2**	**1,616.2**	**519.6**	**-**	**(1.1)**	**(1.1)**	**-**	**8,710.5**	**2,204**

(1) Utility and Customer Costs in 2022 Dollars.

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Air Sealing, Cord Wood	E21B1a001	23	23	10.9	10.9	163.0	163.0	-	-	6.0	6.0	233.9	224.7	3,509.0	3,370.1
B1a - HEA (Weatherization	Air Sealing, Electric	E21B1a002	15	15	21.7	21.7	326.0	326.0	6.9	6.9	-	-	-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Gas	E21B1a003	-	-									-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Kerosene	E21B1a004	88	87	22.4	22.2	336.5	332.7	-	-	12.4	12.2	656.8	623.6	9,852.3	9,354.6
B1a - HEA (Weatherization	Air Sealing, Oil	E21B1a005	228	226	43.4	43.0	650.7	645.0	-	-	23.9	23.7	2,208.0	2,101.9	33,119.4	31,528.8
B1a - HEA (Weatherization	Air Sealing, Propane	E21B1a006	68	67	15.7	15.5	235.2	231.8	-	-	8.6	8.5	407.3	385.4	6,108.8	5,780.6
B1a - HEA (Weatherization	Air Sealing, Wood Pellets	E21B1a007	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Cord Wood	E21B1a084	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Electric	E21B1a085	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Gas	E21B1a086	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Kerosene	E21B1a087	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Oil	E21B1a088	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Propane	E21B1a089	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Wood Pellets	E21B1a090	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Electric	E21B1a009	19	19	0.8	0.8	5.7	5.7	0.2	0.2	0.1	0.1	-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Gas	E21B1a010	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Kerosene	E21B1a011	26	26	-	-	-	-	-	-	-	-	3.7	3.7	25.8	25.8
B1a - HEA (Weatherization	Faucet Aerator, Oil	E21B1a012	68	67	-	-	-	-	-	-	-	-	9.7	9.5	67.6	66.6
B1a - HEA (Weatherization	Faucet Aerator, Propane	E21B1a013	20	20	-	-	-	-	-	-	-	-	2.8	2.8	19.9	19.9
B1a - HEA (Weatherization	Tank Wrap, Electric	E21B1a091	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Gas	E21B1a092	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Kerosene	E21B1a093	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Oil	E21B1a094	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Propane	E21B1a095	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Electric	E21B1a016	13	13	1.7	1.7	25.8	25.8	0.3	0.3	0.1	0.1	-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Gas	E21B1a017	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Kerosene	E21B1a018	13	13	-	-	-	-	-	-	-	-	7.5	7.5	112.3	112.3
B1a - HEA (Weatherization	Hand Held Showerhead, Oil	E21B1a019	34	34	-	-	-	-	-	-	-	-	19.6	19.6	293.8	293.8
B1a - HEA (Weatherization	Hand Held Showerhead, Propane	E21B1a020	10	10	-	-	-	-	-	-	-	-	5.8	5.8	86.4	86.4
B1a - HEA (Weatherization	Insulation, Cord Wood	E21B1a022	23	23	31.4	31.4	783.8	783.8	-	-	17.3	17.3	658.6	619.9	16,465.2	15,496.9
B1a - HEA (Weatherization	Insulation, Electric	E21B1a023	13	13	36.1	36.1	901.8	901.8	11.5	11.5	-	-	-	-	-	-
B1a - HEA (Weatherization	Insulation, Gas	E21B1a024	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Kerosene	E21B1a025	86	85	33.5	33.1	838.0	828.3	-	-	18.5	18.3	1,352.7	1,258.4	33,818.3	31,459.4
B1a - HEA (Weatherization	Insulation, Oil	E21B1a026	224	222	144.1	142.8	3,601.4	3,569.2	-	-	79.4	78.7	5,034.0	4,695.7	125,850.7	117,392.1
B1a - HEA (Weatherization	Insulation, Propane	E21B1a027	65	64	43.2	42.6	1,080.6	1,064.0	-	-	23.8	23.5	901.7	835.7	22,543.4	20,891.3
B1a - HEA (Weatherization	Insulation, Wood Pellets	E21B1a028	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Cord Wood	E21B1a077	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Electric	E21B1a078	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Gas	E21B1a079	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Kerosene	E21B1a080	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Oil	E21B1a081	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Propane	E21B1a082	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Wood Pellets	E21B1a083	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Electric	E21B1a030	11	11	1.5	1.5	21.8	21.8	0.3	0.3	0.1	0.1	-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Gas	E21B1a031	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Kerosene	E21B1a032	8	8	-	-	-	-	-	-	-	-	4.6	4.6	69.1	69.1
B1a - HEA (Weatherization	Low Flow Showerhead, Oil	E21B1a033	20	20	-	-	-	-	-	-	-	-	11.5	11.5	172.8	172.8
B1a - HEA (Weatherization	Low Flow Showerhead, Propane	E21B1a034	6	6	-	-	-	-	-	-	-	-	3.5	3.5	51.8	51.8
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Electric	E21B1a037	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Gas	E21B1a038	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Kerosene	E21B1a039	18	18	-	-	-	-	-	-	-	-	5.9	5.9	88.2	88.2
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Oil	E21B1a040	80	79	-	-	-	-	-	-	-	-	627.2	619.4	9,408.4	9,290.8
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Propane	E21B1a041	11	11	-	-	-	-	-	-	-	-	7.3	7.3	108.8	108.8
B1a - HEA (Weatherization	Hot Water Setback, Electric	E21B1a042	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Gas	E21B1a060	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Kerosene	E21B1a061	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Oil	E21B1a062	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Propane	E21B1a063	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	DHW Heat Pump Water Heater	E21B1a043	13	13	21.5	21.5	279.6	279.6	3.5	3.5	2.0	2.0	-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Electric	E21B1a096	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Gas	E21B1a097	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Propane	E21B1a099	30	30	18.6	18.6	241.5	241.5	2.6	2.6	1.4	1.4	68.4	68.4	888.6	888.6
B1a - HEA (Weatherization	Indirect Water Heater, Oil	E21B1a098	11	11	8.5	8.5	110.5	110.5	1.2	1.2	0.6	0.6	19.4	19.4	252.6	252.6
B1a - HEA (Weatherization	LED Bulb, General Service Lamps	E21B1a044	2,265	2,242	143.9	142.5	287.8	284.9	31.1	30.8	20.0	19.8	(327.0)	(323.7)	(654.0)	(647.3)
B1a - HEA (Weatherization	LED Bulb, Linear	E21B1a045	145	144	22.5	22.4	225.1	223.6	4.9	4.8	3.1	3.1	(51.2)	(50.8)	(511.5)	(508.0)
B1a - HEA (Weatherization	LED Bulb, Other Specialty	E21B1a046	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Reflector	E21B1a047	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Fixture	E21B1a048	520	515	83.1	82.3	166.1	164.5	17.9	17.8	11.6	11.5	(188.7)	(186.9)	(377.4)	(373.8)
B1a - HEA (Weatherization	Refrigerator	E21B1a049	279	276	230.4	228.0	2,765.1	2,735.4	26.3	26.0	32.3	31.9	-	-	-	-
B1a - HEA (Weatherization	Freezer	E21B1a050	-	-									-	-	-	-
B1a - HEA (Weatherization	Clothes Washer	E21B1a051	-	-									-	-	-	-
B1a - HEA (Weatherization	Clothes Dryer	E21B1a052	-	-									-	-	-	-
B1a - HEA (Weatherization	Dehumidifier	E21B1a053	-	-									-	-	-	-
B1a - HEA (Weatherization	Room Air Conditioner	E21B1a054	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Cord Wood	E21B1a055	49	49	0.9	0.9	23.1	23.1	-	-	0.5	0.5	44.3	44.3	1,107.7	1,107.7
B1a - HEA (Weatherization	Window Replacement, Electric	E21B1a064	31	31	3.5	3.5	86.8	86.8	1.1	1.1	-	-	-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Gas	E21B1a065	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Kerosene	E21B1a066	189	187	1.6	1.6	40.1	39.7	-	-	0.9	0.9	142.0	140.5	3,549.1	3,511.5
B1a - HEA (Weatherization	Window Replacement, Oil	E21B1a067	489	484	5.8	5.7	143.8	142.3	-	-	3.2	3.1	300.7	297.7	7,518.2	7,441.3
B1a - HEA (Weatherization	Window Replacement, Propane	E21B1a068	147	146	1.7	1.7	41.7	41.4	-	-	0.9	0.9	127.8	126.9	3,193.9	3,172.2
B1a - HEA (Weatherization	Window Replacement, Wood Pellets	E21B1a069	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Cord Wood	E21B1a100	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Electric	E21B1a101	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Gas	E21B1a102	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Kerosene	E21B1a103	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Oil	E21B1a104	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Propane	E21B1a105	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Wood Pellets	E21B1a106	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Cord Wood	E21B1a070	8	8	0.1	0.1	3.7	3.7	-	-	0.1	0.1	7.5	7.5	186.6	186.6
B1a - HEA (Weatherization	Insulated Door, Electric	E21B1a071	5	5	1.9	1.9	47.1	47.1	0.6	0.6	-	-	-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Gas	E21B1a072	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Kerosene	E21B1a073	31	31	0.3	0.3	6.8	6.8	-	-	0.1	0.1	13.2	13.2	330.9	330.9
B1a - HEA (Weatherization	Insulated Door, Oil	E21B1a074	80	79	1.3	1.3	31.9	31.5	-	-	0.7	0.7	68.7	67.8	1,716.4	1,694.9
B1a - HEA (Weatherization	Insulated Door, Propane	E21B1a075	24	24	0.2	0.2	5.3	5.3	-	-	0.1	0.1	22.3	22.3	558.5	558.5
B1a - HEA (Weatherization	Insulated Door, Wood Pellets	E21B1a076	-	-									-	-	-	-
B1a - HEA (Weatherization	Visual Audit	E21B1a056	-	-									-	-	-	-
B1a - HEA (Weatherization	Baseload Audit - SF	E21B1a057	-	-									-	-	-	-
B1a - HEA (Weatherization	Baseload Audit - MF	E21B1a058	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Income Kits	E21B1a059	-	-									-	-	-	-
			-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Gas	E21B1b001	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Kerosene	E21B1b002	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Oil	E21B1b003	93	91	60.3	59.0	1,144.9	1,120.3	17.8	17.4	-	-	1,487.9	1,455.9	28,270.5	27,662.5
B1b - HEA (HVAC Systems	Boiler Replacement, Propane	E21B1b004	14	14	4.5	4.5	84.9	84.9	1.3	1.3	-	-	92.5	92.5	1,757.8	1,757.8
B1b - HEA (HVAC Systems	Furnace Replacement, Gas	E21B1b005	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Furnace Replacement, Kerosene	E21B1b006	77	75	6.1	6.0	104.3	101.6	2.0	2.0	-	-	655.8	638.8	11,148.3	10,858.8
B1b - HEA (HVAC Systems	Furnace Replacement, Oil	E21B1b007	83	82	9.9	9.7	167.7	165.7	2.2	2.2	-	-	861.6	851.2	14,647.0	14,470.5
B1b - HEA (HVAC Systems	Furnace Replacement, Propane	E21B1b008	37	37	4.4	4.4	74.8	74.8	1.0	1.0	-	-	306.2	306.2	5,205.5	5,205.5
B1b - HEA (HVAC Systems	Programmable Thermostat, Electric	E21B1b009	49	49	11.2	11.2	167.9	167.9	17.8	17.8	-	-	-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Gas	E21B1b010	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Kerosene	E21B1b011	33	33	-	-	-	-	-	-	-	-	105.1	105.1	1,576.6	1,576.6
B1b - HEA (HVAC Systems	Programmable Thermostat, Oil	E21B1b012	137	136	-	-	-	-	-	-	-	-	436.3	433.2	6,545.2	6,497.4
B1b - HEA (HVAC Systems	Programmable Thermostat, Propane	E21B1b013	49	49	-	-	-	-	-	-	-	-	156.1	156.1	2,341.0	2,341.0
B1b - HEA (HVAC Systems	Programmable Thermostat, Wood Pellets	E21B1b014	47	47	-	-	-	-	-	-	-	-	149.7	149.7	2,245.4	2,245.4
B1b - HEA (HVAC Systems	Wifi Thermostat, Electric	E21B1b015	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Gas	E21B1b016	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1b - HEA (HVAC Systems	Wifi Thermostat, Kerosene	E21B1b017	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Oil	E21B1b018	15	15	-	-	-	-	-	-	-	-	80.5	80.5	1,208.0	1,208.0
B1b - HEA (HVAC Systems	Wifi Thermostat, Propane	E21B1b019	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Wood Pellets	E21B1b020	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Mini Split HP (cooling)	E21B1b021	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Mini Split HP (heating)	E21B1b022	8	8	38.3	38.3	688.6	688.6	12.1	12.1	-	-	-	-	-	-
B1b - HEA (HVAC Systems	ES Central AC	E21B1b023	4	4	0.7	0.7	12.1	12.1	-	-	0.4	0.4	-	-	-	-
B1b - HEA (HVAC Systems	Oil K1 HVAC Repair or Cleaning	E21B1b024	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Gas LP HVAC Repair or Cleaning	E21B1b025	-	-									-	-	-	-
	Home Energy Assistance Subtotal				**1,087.3**	**1,077.5**	**15,921.8**	**15,782.5**	**162.7**	**161.4**	**268.2**	**265.7**	**16,741.2**	**15,961.9**	**354,477.1**	**337,099.6**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A1a - ES Homes	Cooling, Electric, SF	E21A1a001	48	49	8.2	8.3	206.1	208.4	-	-	4.5	4.6	-	-	-	-
A1a - ES Homes	Heating, Electric, SF	E21A1a002	48	49	362.4	366.5	9,059.7	9,162.5	115.0	116.4	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, SF	E21A1a003	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, SF	E21A1a004	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, SF	E21A1a005	265	268	108.4	109.6	2,710.8	2,739.5	31.6	-	-	-	8,673.9	8,246.5	216,847.0	206,163.6
A1a - ES Homes	Heating, Wood Pellets, SF	E21A1a006	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, SF	E21A1a007	48	49	70.0	70.8	1,050.7	1,062.6	13.8	13.9	5.3	5.4	-	-	-	-
A1a - ES Homes	Hot Water, Gas, SF	E21A1a008	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, SF	E21A1a009	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, SF	E21A1a010	265	268	36.6	37.0	548.5	554.3	5.2	-	2.8	-	927.2	881.5	13,907.9	13,222.7
A1a - ES Homes	Hot Water, Wood Pellets, SF	E21A1a011	-	-									-	-	-	-
A1a - ES Homes	Cooling, Electric, MF	E21A1a012	85	86	3.7	3.8	93.0	94.1	-	-	2.1	2.1	-	-	-	-
A1a - ES Homes	Heating, Electric, MF	E21A1a013	85	86	91.2	92.3	2,280.6	2,307.4	29.0	29.3	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, MF	E21A1a014	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, MF	E21A1a015	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, MF	E21A1a016	28	28	4.0	4.0	100.7	100.6	1.2	-	-	-	1,265.4	1,164.1	31,634.2	29,102.1
A1a - ES Homes	Heating, Wood Pellets, MF	E21A1a017	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, MF	E21A1a018	85	86	45.5	46.1	682.9	691.0	9.0	9.1	3.5	3.5	-	-	-	-
A1a - ES Homes	Hot Water, Gas, MF	E21A1a019	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, MF	E21A1a020	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, MF	E21A1a021	28	28	-	-	-	-	-	-	-	-	208.0	191.3	3,119.8	2,870.0
A1a - ES Homes	Hot Water, Wood Pellets, MF	E21A1a022	-	-									-	-	-	-
A1a - ES Homes	LED Bulb	E21A1a023	-	-									-	-	-	-
A1a - ES Homes	LED Fixture	E21A1a024	-	-									-	-	-	-
A1a - ES Homes	Refrigerator	E21A1a025	837	846	37.0	37.4	444.1	448.7	4.2	4.3	5.2	5.2	-	-	-	-
A1a - ES Homes	Clothes Washer	E21A1a026	409	413	36.8	37.1	404.3	408.4	5.2	5.2	4.9	4.9	28.6	28.9	314.8	318.0
A1a - ES Homes	Clothes Dryer	E21A1a027	139	140	22.2	22.5	266.7	269.5	3.8	3.8	2.9	2.9	-	-	-	-
A1a - ES Homes	HERS - Lighting and Appliances	E21A1a028	-	-									-	-	-	-
A1a - ES Homes	Residential New Construction Code Compliance	E21A1a029	-	-									-	-	-	-
	ES Homes Subtotal				**826.2**	**835.3**	**17,848.0**	**18,046.9**	**217.9**	**182.0**	**31.1**	**28.7**	**11,103.0**	**10,512.4**	**265,823.7**	**251,676.5**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherizat	Air Sealing, Cord Wood	E21A2a001	57	58	20.0	20.3	300.3	304.3	-	-	11.0	11.2	202.9	193.5	3,042.9	2,902.7
A2a - HPwES (Weatherizat	Air Sealing, Electric	E21A2a002	45	46	108.6	110.7	1,629.0	1,660.8	34.5	35.1	-	-	-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Gas	E21A2a003	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Kerosene	E21A2a004	4	4	0.2	0.2	2.9	2.6	-	-	0.1	0.1	20.9	17.9	313.1	267.8
A2a - HPwES (Weatherizat	Air Sealing, Oil	E21A2a005	574	580	23.5	23.7	352.5	355.9	-	-	13.0	13.1	3,442.9	3,271.7	51,644.0	49,075.6
A2a - HPwES (Weatherizat	Air Sealing, Propane	E21A2a006	199	201	57.9	58.4	868.0	875.8	-	-	31.9	32.2	1,164.3	1,105.8	17,464.0	16,586.3
A2a - HPwES (Weatherizat	Air Sealing, Wood Pellets	E21A2a007	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Cord Wood	E21A2a070	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Electric	E21A2a071	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Gas	E21A2a072	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Kerosene	E21A2a073	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Oil	E21A2a074	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Propane	E21A2a075	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Wood Pellets	E21A2a076	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Electric	E21A2a009	7	7	0.3	0.3	2.1	2.2	0.1	0.1	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Gas	E21A2a010	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Kerosene	E21A2a011	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Oil	E21A2a012	35	36	-	-	-	-	-	-	-	-	6.2	6.3	43.4	44.4
A2a - HPwES (Weatherizat	Faucet Aerator, Propane	E21A2a013	9	9	-	-	-	-	-	-	-	-	1.6	1.6	10.9	11.1
A2a - HPwES (Weatherizat	Tank Wrap, Electric	E21A2a077	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Gas	E21A2a078	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Kerosene	E21A2a079	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Oil	E21A2a080	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Propane	E21A2a081	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Electric	E21A2a016	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Gas	E21A2a017	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Kerosene	E21A2a018	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Oil	E21A2a019	26	27	-	-	-	-	-	-	-	-	18.9	19.3	283.0	289.3
A2a - HPwES (Weatherizat	Hand Held Showerhead, Propane	E21A2a020	2	2	-	-	-	-	-	-	-	-	1.6	1.4	23.6	21.4
A2a - HPwES (Weatherizat	Insulation, Cord Wood	E21A2a022	61	61	153.0	154.2	3,824.8	3,854.6	-	-	84.4	85.0	1,499.1	1,422.0	37,478.0	35,549.3
A2a - HPwES (Weatherizat	Insulation, Electric	E21A2a023	46	47	602.5	612.7	15,062.9	15,316.7	191.3	194.5	-	-	-	-	-	-
A2a - HPwES (Weatherizat	Insulation, Gas	E21A2a024	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Insulation, Kerosene	E21A2a025	4	4	0.5	0.4	11.6	10.5	-	-	0.3	0.2	98.3	84.1	2,458.5	2,102.6
A2a - HPwES (Weatherizat	Insulation, Oil	E21A2a026	645	651	220.3	222.3	5,506.4	5,558.6	-	-	121.5	122.6	22,529.6	21,405.4	563,238.8	535,136.0
A2a - HPwES (Weatherizat	Insulation, Propane	E21A2a027	216	218	272.1	275.0	6,801.7	6,874.3	-	-	150.0	151.6	6,557.0	6,237.3	163,925.5	155,932.0
A2a - HPwES (Weatherizat	Insulation, Wood Pellets	E21A2a028	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Cord Wood	E21A2a063	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Electric	E21A2a064	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Gas	E21A2a065	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Kerosene	E21A2a066	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Oil	E21A2a067	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Propane	E21A2a068	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Wood Pellets	E21A2a069	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Electric	E21A2a030	3	3	0.5	0.4	6.8	6.2	0.1	0.1	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Gas	E21A2a031	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Kerosene	E21A2a032	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Oil	E21A2a033	13	13	-	-	-	-	-	-	-	-	9.4	9.3	141.5	139.3
A2a - HPwES (Weatherizat	Low Flow Showerhead, Propane	E21A2a034	4	4	-	-	-	-	-	-	-	-	3.1	2.9	47.2	42.9
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Electric	E21A2a037	1	1	0.2	0.1	2.4	2.2	0.0	0.0	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Gas	E21A2a038	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Kerosene	E21A2a039	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Oil	E21A2a040	40	40	-	-	-	-	-	-	-	-	44.2	44.7	663.5	669.9
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Propane	E21A2a041	13	13	-	-	-	-	-	-	-	-	15.2	15.0	228.5	224.9
A2a - HPwES (Weatherizat	Hot Water Setback, Electric	E21A2a042	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Gas	E21A2a059	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Kerosene	E21A2a060	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Oil	E21A2a061	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Propane	E21A2a062	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherizat	DHW Heat Pump Water Heater	E21A2a043	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Indirect Water Heater, Oil	E21A2a082	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Indirect Water Heater, Propane	E21A2a083	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, General Service Lamps	E21A2a044	3,227	3,259	108.3	109.3	216.5	218.7	23.4	23.6	15.1	15.2	(256.2)	(258.8)	(512.4)	(517.5)
A2a - HPwES (Weatherizat	LED Bulb, Linear	E21A2a045	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Other Specialty	E21A2a046	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Reflector	E21A2a047	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Fixture	E21A2a048	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Refrigerator	E21A2a049	45	46	34.3	35.0	412.1	420.1	3.9	4.0	4.8	4.9	-	-	-	-
A2a - HPwES (Weatherizat	Freezer	E21A2a053	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Clothes Washer	E21A2a054	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Clothes Dryer	E21A2a055	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Dehumidifier	E21A2a056	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Room Air Conditioner	E21A2a057	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Triple Pane Window	E21A2a058	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Cord Wood	E21A2a084	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Electric	E21A2a085	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Gas	E21A2a086	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Kerosene	E21A2a087	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Oil	E21A2a088	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Propane	E21A2a089	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Wood Pellets	E21A2a090	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Visual Audit Oil Savings	E21A2a050	372	376	-	-	-	-	-	-	-	-	2,765.3	2,630.9	41,290.3	36,174.7
A2a - HPwES (Weatherizat	Visual Audit Propane Savings	E21A2a051	158	160	-	-	-	-	-	-	-	-	955.1	907.6	14,192.4	12,478.9
A2a - HPwES (Weatherizat	Visual Audit Electric Savings	E21A2a052	466	470	235.6	237.9	751.1	1,189.3	74.8	75.5	-	-	-	-	-	-
			-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Gas	E21A2b001	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Kerosene	E21A2b002	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Oil	E21A2b003	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Propane	E21A2b004	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Gas	E21A2b005	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Kerosene	E21A2b006	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Oil	E21A2b007	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Propane	E21A2b008	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Electric	E21A2b009	8	8	1.8	1.9	27.6	28.6	2.9	3.0	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Gas	E21A2b010	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Kerosene	E21A2b011	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Oil	E21A2b012	88	89	-	-	-	-	-	-	-	-	347.8	351.6	5,216.5	5,273.4
A2b - HPwES (HVAC Syste	Programmable Thermostat, Propane	E21A2b013	29	29	-	-	-	-	-	-	-	-	113.0	114.6	1,695.4	1,718.3
A2b - HPwES (HVAC Syste	Programmable Thermostat, Wood Pellets	E21A2b014	10	10	-	-	-	-	-	-	-	-	39.1	39.5	586.9	592.5
A2b - HPwES (HVAC Syste	Wifi Thermostat, Electric	E21A2b015	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Gas	E21A2b016	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Kerosene	E21A2b017	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Oil	E21A2b018	168	170	-	-	-	-	-	-	-	-	1,121.2	1,132.0	16,817.6	16,979.8
A2b - HPwES (HVAC Syste	Wifi Thermostat, Propane	E21A2b019	41	41	-	-	-	-	-	-	-	-	266.5	268.4	3,998.1	4,025.7
A2b - HPwES (HVAC Syste	Wifi Thermostat, Wood Pellets	E21A2b020	19	19	-	-	-	-	-	-	-	-	65.5	66.5	981.8	997.1
A2b - HPwES (HVAC Syste	ES Central AC	E21A2b021	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Boiler Circulator Pump	E21A2b022	576	581	47.0	47.5	893.8	902.3	13.9	14.0	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Furnace	E21A2b023	237	239	2.0	2.0	36.4	36.8	0.6	0.6	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Central AC	E21A2b024	634	640	37.3	37.6	671.2	677.6	-	-	20.6	20.8	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Room AC	E21A2b025	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Mini-Split AC / HP	E21A2b026	-	-									-	-	-	-
	Home Performance with Energy Star Subtotal				**1,925.8**	**1,950.1**	**37,380.1**	**38,298.3**	**345.4**	**350.6**	**452.6**	**457.0**	**41,032.5**	**39,090.2**	**925,273.0**	**876,718.4**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A3a - ES Lighting	LED Bulb, General Service Lamps	E21A3a001	35,294	-	214.3		643.0		46.3		29.8		(486.9)	-	(1,460.8)	-
A3a - ES Lighting	LED Bulb, Linear	E21A3a002	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Other Specialty	E21A3a003	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Reflector	E21A3a004	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, General Service Lamps (Hard to Reach)	E21A3a005	120,000	140,400	1,362.3	1,223.3	4,087.0	2,446.5	294.1	264.1	189.7	170.3	(3,095.2)	(2,779.2)	(9,285.7)	(5,558.5)
A3a - ES Lighting	LED Bulb, Linear (Hard to Reach)	E21A3a006	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Other Specialty (Hard to Reach)	E21A3a007	33,333	39,000	341.9	307.0	1,025.6	614.0	73.8	66.3	47.6	42.7	(776.7)	(697.4)	(2,330.2)	(1,394.9)
A3a - ES Lighting	LED Bulb, Reflector (Hard to Reach)	E21A3a008	-	-									-	-	-	-
A3a - ES Lighting	LED Fixture	E21A3a009	-	-									-	-	-	-
A3a - ES Lighting	LED Fixture (Hard to Reach)	E21A3a010	-	-									-	-	-	-
			-	-									-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier I	E21A3b001	1,200	1,320	111.1	122.2	555.4	611.0	9.0	9.9	6.1	6.7	-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier II	E21A3b002	600	660	72.0	79.2	360.2	396.2	6.4	7.1	4.3	4.8	-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (cooling)	E21A3b003	186	205	38.8	42.7	698.2	768.0	-	-	21.4	23.5	-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (heating)	E21A3b004	186	205	174.5	192.0	3,141.6	3,455.8	79.3	87.3	-	-	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (cooling)	E21A3b005	3,091	3,400	356.9	392.6	6,424.0	7,066.4	-	-	164.9	181.4	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (heating)	E21A3b006	3,091	3,400	1,181.6	1,299.8	21,268.7	23,395.6	537.1	590.8	-	-	-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Downstream	E21A3b007	982	1,041	944.0	1,000.7	12,272.3	13,008.6	154.9	164.2	85.7	90.8	2,111.0	2,237.7	27,443.4	29,090.1
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Downstream	E21A3b008	237	252	134.1	142.1	1,743.2	1,847.8	22.0	23.3	12.2	12.9	510.0	540.6	6,630.4	7,028.2
A3b - ES Appliances	Heat Pump Swimming Pool Heater	E21A3b009	-	-									-	-	-	-
A3b - ES Appliances	ES Clothes Dryers	E21A3b010	1,620	1,717	259.8	275.4	3,118.2	3,305.3	44.3	46.9	34.1	36.1	-	-	-	-
A3b - ES Appliances	Dryer Heat Pump	E21A3b011	74	78	31.2	33.0	373.9	396.4	5.3	5.6	4.1	4.3	-	-	-	-
A3b - ES Appliances	Dryer Hybrid	E21A3b012	9	10	1.9	2.0	23.0	24.4	0.3	0.3	0.3	0.3	-	-	-	-
A3b - ES Appliances	ECM Motor for FWH Circulating Pump	E21A3b013	-	-									-	-	-	-
A3c - ES HVAC Systems	ES AC (central) 3 ton	E21A3b015	177	188	32.8	34.8	590.5	625.9	-	-	18.1	19.2	-	-	-	-
A3b - ES Appliances	Room Air Conditioner	E21A3b016	595	631	19.6	20.8	176.7	187.3	-	-	10.2	10.8	-	-	-	-
A3b - ES Appliances	ES Clothes Washers	E21A3b017	1,576	1,671	141.7	150.2	1,558.5	1,652.0	19.9	21.1	18.8	19.9	110.3	116.9	1,213.5	1,286.3
A3b - ES Appliances	Washer Tier CEE Tier 2+	E21A3b018	1,118	1,185	155.3	164.6	1,708.2	1,810.7	21.8	23.1	20.6	21.8	536.6	568.8	5,903.0	6,257.2
A3b - ES Appliances	ES Dehumidifier	E21A3b019	1,240	1,314	102.1	108.2	1,224.6	1,298.1	4.1	4.4	19.6	20.7	-	-	-	-
A3b - ES Appliances	ES Dishwasher	E21A3b020	-	-									-	-	-	-
A3b - ES Appliances	ES Freezers	E21A3b021	-	-									-	-	-	-
A3b - ES Appliances	Refrigerator	E21A3b022	1,720	1,823	76.0	80.6	912.3	967.0	8.7	9.2	10.7	11.3	-	-	-	-
A3b - ES Appliances	Refrigerator CEE Tier 2+	E21A3b023	402	426	38.8	41.1	465.0	492.9	4.4	4.7	5.4	5.8	-	-	-	-
A3b - ES Appliances	ES Pool Pumps (Variable Speed)	E21A3b024	321	340	411.7	436.3	4,116.5	4,363.5	-	-	238.0	252.2	-	-	-	-
A3b - ES Appliances	Room Air Purifier	E21A3b025	642	681	243.2	257.8	2,188.6	2,319.9	27.8	29.4	27.8	29.4	-	-	-	-
A3c - ES HVAC Systems	Wifi Thermostat (Heating & Cooling)	E21A3b026	420	445	19.3	20.5	289.8	307.2	-	-	-	-	2,066.4	2,190.4	30,996.0	32,855.8
A3b - ES Appliances	Primary Refrigerator Recycling	E21A3b027	571	605	586.4	621.6	2,932.1	3,108.0	67.0	71.0	82.2	87.1	-	-	-	-
A3b - ES Appliances	Secondary Refrigerator Recycling	E21A3b028	20	21	20.5	21.8	102.7	108.9	1.9	2.0	3.2	3.4	-	-	-	-
A3b - ES Appliances	Secondary Freezer Recycling	E21A3b029	98	104	75.4	79.9	301.4	319.5	7.4	7.8	9.9	10.5	-	-	-	-
A3b - ES Appliances	Room Air Conditioner Recycling	E21A3b030	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit Resistance	E21A3b031	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit HP	E21A3b032	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit HP	E21A3b033	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit Resistance	E21A3b034	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Midstream	E21A3b035	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Midstream	E21A3b036	-	-									-	-	-	-
	ES Products Subtotal				**7,147.2**	**7,150.0**	**72,301.4**	**74,896.9**	**1,435.9**	**1,438.7**	**1,064.5**	**1,066.1**	**975.5**	**2,177.8**	**59,109.6**	**69,564.2**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1a - LCI Retrofit	Custom Large Compressed Air Retro	E21C1a001	3	3	285.8	277.2	4,246.1	4,118.7	31.8	-	31.8	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Hot Water Retro	E21C1a002	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large HVAC Retro	E21C1a003	2	2	510.0	494.7	5,777.9	5,604.6	74.6	72.4	61.4	59.6	-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Interior	E21C1a004	68	66	5,706.9	5,224.7	60,186.2	55,100.8	696.9	638.1	914.0	836.8	(3,434.2)	(3,144.1)	(36,218.3)	(33,158.1)
C1a - LCI Retrofit	Custom Large Lighting Retro - Exterior	E21C1a047	21	20	305.5	279.7	3,110.4	2,847.6	61.2	56.0	-	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Controls	E21C1a048	1	1	3.6	3.3	33.4	30.6	0.0	0.0	0.1	0.0	(8.5)	(7.7)	(79.5)	(72.8)
C1a - LCI Retrofit	Custom Large Motors Retro	E21C1a005	1	1	99.6	96.6	1,483.7	1,439.2	3.9	3.8	4.0	3.9	-	-	-	-
C1a - LCI Retrofit	Custom Large Process Retro	E21C1a006	2	2	1,067.8	1,035.8	16,409.5	15,917.2	155.6	151.0	164.3	159.3	-	-	-	-
C1a - LCI Retrofit	Custom Large Refrigeration Retro	E21C1a007	10	10	379.3	367.9	4,139.2	4,015.0	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Other Retro	E21C1a008	9	9	654.8	635.2	4,287.3	4,158.7	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Daylight Dimming	E21C1a009	2	2	86.1	78.8	774.7	709.3	1.2	1.1	1.2	1.1	(235.1)	(215.2)	(2,115.6)	(1,936.9)
C1a - LCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C1a010	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C1a011	4	4	127.2	116.5	1,295.3	1,185.8	25.5	23.3	-	-	-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C1a012	1	1	7.4	6.8	66.4	60.8	0.6	0.5	0.7	0.7	(5.1)	(4.7)	(45.9)	(42.0)
C1a - LCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C1a013	21	20	1,489.6	1,363.7	15,709.3	14,382.0	116.0	106.2	150.3	137.6	(1,030.3)	(943.3)	(10,866.0)	(9,947.9)
C1a - LCI Retrofit	Lighting Occupancy Sensors	E21C1a014	2	2	47.5	43.5	427.4	391.3	0.6	0.6	0.7	0.6	(129.7)	(118.7)	(1,167.1)	(1,068.5)
C1a - LCI Retrofit	Boiler Reset Controls, Electric	E21C1a015	-	-									-	-	-	-
C1a - LCI Retrofit	Case Motor Replacement	E21C1a016	-	-									-	-	-	-
C1a - LCI Retrofit	Cooler Night Cover	E21C1a017	-	-									-	-	-	-
C1a - LCI Retrofit	Demand Control Ventilation	E21C1a018	-	-									-	-	-	-
C1a - LCI Retrofit	Door Heater Controls	E21C1a019	-	-									-	-	-	-
C1a - LCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C1a020	-	-									-	-	-	-
C1a - LCI Retrofit	Duct Sealing, Electric	E21C1a021	-	-									-	-	-	-
C1a - LCI Retrofit	Ductless Mini Split Heat Pump	E21C1a022	-	-									-	-	-	-
C1a - LCI Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C1a023	-	-									-	-	-	-
C1a - LCI Retrofit	Electronic Defrost Control	E21C1a024	-	-									-	-	-	-
C1a - LCI Retrofit	Energy Management System, Electric	E21C1a025	1	1	70.3	68.2	702.8	681.7	7.0	6.8	6.7	6.5	-	-	-	-
C1a - LCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C1a026	-	-									-	-	-	-
C1a - LCI Retrofit	Evaporator Fan Control	E21C1a027	-	-									-	-	-	-
C1a - LCI Retrofit	Faucet Aerator, Electric	E21C1a028	-	-									-	-	-	-
C1a - LCI Retrofit	Hotel Occupancy Sensor	E21C1a031	-	-									-	-	-	-
C1a - LCI Retrofit	Low Pressure Drop Filter	E21C1a032	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C1a033	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead, Electric	E21C1a034	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Open Drip	E21C1a035	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C1a036	-	-									-	-	-	-
C1a - LCI Retrofit	Novelty Cooler Shutoff	E21C1a037	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Heating, Electric	E21C1a038	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C1a039	-	-									-	-	-	-
C1a - LCI Retrofit	Pre Rinse Spray Valve, Electric	E21C1a040	-	-									-	-	-	-
C1a - LCI Retrofit	Programmable Thermostat, Electric	E21C1a041	-	-									-	-	-	-
C1a - LCI Retrofit	Steam Trap, Electric	E21C1a042	-	-									-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive	E21C1a043	3	3	125.9	122.1	1,888.6	1,832.0	7.4	7.2	6.6	6.4	-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive with Motor	E21C1a044	1	1	4.0	3.9	60.5	58.7	0.2	0.2	0.2	0.2	-	-	-	-
C1a - LCI Retrofit	Vending Miser	E21C1a045	-	-									-	-	-	-
C1a - LCI Retrofit	Zero Loss Condensate Drain	E21C1a046	-	-									-	-	-	-
C1a - LCI Retrofit	Large Retrocommissioning	E21C1a049	-	-									-	-	-	-
			-	-									-	-	-	-
C1b - LCI New Equipment a	Custom Large Compressed Air New	E21C1b001	6	5	1,277.5	1,239.1	18,974.2	18,405.0	141.9	137.7	141.9	137.7	-	-	-	-
C1b - LCI New Equipment a	Custom Large Hot Water New	E21C1b002	-	-									-	-	-	-
C1b - LCI New Equipment a	Custom Large HVAC New	E21C1b003	18	17	412.6	400.2	5,155.1	5,000.4	27.4	26.5	71.0	68.9	-	-	-	-
C1b - LCI New Equipment a	Custom Large Lighting New - Interior	E21C1b004	13	12	3,141.2	2,905.4	47,117.9	43,581.4	383.6	354.8	503.1	465.3	(443.9)	(410.6)	(6,658.9)	(6,159.1)
C1b - LCI New Equipment a	Custom Large Lighting New - Exterior	E21C1b054	9	9	117.6	107.7	1,764.2	1,615.2	23.5	21.6	-	-	-	-	-	-
C1b - LCI New Equipment a	Custom Large Lighting New - Controls	E21C1b055	1	1	1.1	1.1	11.5	10.5	0.0	0.0	0.0	0.0	(2.7)	(2.5)	(27.3)	(25.0)
C1b - LCI New Equipment a	Custom Large Motors New	E21C1b005	4	4	45.2	43.8	677.3	657.0	4.0	3.9	4.8	4.6	-	-	-	-
C1b - LCI New Equipment a	Custom Large Process New	E21C1b006	5	5	400.0	392.0	5,227.3	5,122.8	29.1	28.6	61.5	60.3	-	-	-	-
C1b - LCI New Equipment a	Custom Large Refrigeration New	E21C1b007	4	4	173.8	168.5	2,432.8	2,359.8	15.4	15.0	15.4	15.0	-	-	-	-
C1b - LCI New Equipment a	Custom Large Other New	E21C1b008	7	7	798.7	774.7	11,915.6	11,558.1	84.8	82.3	80.2	77.8	-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1b - LCI New Equipment	Custom Large Comprehensive Design	E21C1b056	-	-									-	-	-	-
C1b - LCI New Equipment	Daylight Dimming	E21C1b009	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C1b010	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C1b011	1	1	6.6	6.0	98.6	90.2	1.3	1.2	-	-	-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Interior w/ Controls	E21C1b012	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Interior w/o Controls	E21C1b013	1	1	41.6	38.1	624.4	571.7	3.2	3.0	4.2	3.8	(6.8)	(6.2)	(101.4)	(92.9)
C1b - LCI New Equipment	Lighting Occupancy Sensors	E21C1b014	-	-									-	-	-	-
C1b - LCI New Equipment	Advanced Power Strip	E21C1b015	-	-									-	-	-	-
C1b - LCI New Equipment	Air Compressor	E21C1b016	5	5	506.6	491.4	7,599.7	7,371.7	49.7	48.2	59.3	57.6	-	-	-	-
C1b - LCI New Equipment	Air Nozzle	E21C1b017	-	-									-	-	-	-
C1b - LCI New Equipment	Circulator Pump	E21C1b018	-	-									-	-	-	-
C1b - LCI New Equipment	Combination Oven, Electric	E21C1b019	-	-									-	-	-	-
C1b - LCI New Equipment	Compressor Storage	E21C1b020	-	-									-	-	-	-
C1b - LCI New Equipment	Convection Oven, Electric	E21C1b021	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Door Type	E21C1b022	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C1b023	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C1b024	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Single Tank Conveyor	E21C1b025	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Under Counter	E21C1b026	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Door Type	E21C1b027	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C1b028	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Single Tank Conveyor	E21C1b029	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Under Counter	E21C1b030	-	-									-	-	-	-
C1b - LCI New Equipment	Faucet Aerator, Electric	E21C1b031	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Large Vat, Electric	E21C1b032	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Standard Vat, Electric	E21C1b033	-	-									-	-	-	-
C1b - LCI New Equipment	Griddle, Electric	E21C1b034	-	-									-	-	-	-
C1b - LCI New Equipment	Ground Source Heat Pump	E21C1b035	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C1b036	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Full Size	E21C1b037	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Half Size	E21C1b038	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Ice Making Head	E21C1b039	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C1b040	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Continuous	E21C1b041	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Self Contained	E21C1b042	-	-									-	-	-	-
C1b - LCI New Equipment	Low Pressure Drop Filter	E21C1b043	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C1b044	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead, Electric	E21C1b045	-	-									-	-	-	-
C1b - LCI New Equipment	Pre Rinse Spray Valve, Electric	E21C1b046	-	-									-	-	-	-
C1b - LCI New Equipment	Refrigerated Air Dryer	E21C1b047	-	-									-	-	-	-
C1b - LCI New Equipment	Steam Cooker, Electric	E21C1b048	-	-									-	-	-	-
C1b - LCI New Equipment	Unitary Air Conditioner	E21C1b049	4	4	122.8	121.6	1,473.7	1,458.9	-	-	8.4	8.3	-	-	-	-
C1b - LCI New Equipment	Water Source Heat Pump	E21C1b050	-	-									-	-	-	-
C1b - LCI New Equipment	Zero Loss Condensate Drain	E21C1b051	-	-									-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - FL	E21C1b052	-	-									-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - IPLV	E21C1b053	-	-									-	-	-	-
C1b - LCI New Equipment	C&I Large New Construction Code Compliance	E21C1b057	-	-									-	-	-	-
			-	-									-	-	-	-
C1c - LCI Midstream	Midstream Circulator Pump	E21C1c001	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Demand Control Ventilation	E21C1c002	-	-									-	-	-	-
C1c - LCI Midstream	Midstream DMSHP Systems	E21C1c003	3	3	2.7	2.7	32.3	32.3	-	-	0.6	0.6	-	-	-	-
C1c - LCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C1c004		-									-	-	-	-
C1c - LCI Midstream	Midstream ECM Fan Motors	E21C1c005		-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Systems	E21C1c006		-									-	-	-	-
C1c - LCI Midstream	Midstream Unitary Air Conditioners	E21C1c007	4	4	75.1	75.1	900.9	900.9	-	-	5.1	5.1	-	-	-	-
C1c - LCI Midstream	Midstream VRF	E21C1c008	1	1	6.4	6.4	76.8	76.8	-	-	0.4	0.4	-	-	-	-
C1c - LCI Midstream	Midstream Water Source Heat Pump Systems	E21C1c009	4	4	4.0	4.0	101.0	101.0	-	-	0.8	0.8	-	-	-	-
C1c - LCI Midstream	Midstream LED Downlight	E21C1c010	38	38	279.4	254.0	1,637.1	1,488.3	21.6	19.6	30.9	28.1	(72.5)	(65.9)	(425.1)	(386.5)

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1c - LCI Midstream	Midstream LED Exterior	E21C1c011	67	67	148.6	135.1	1,447.2	1,315.7	30.0	27.3	-	-	-	-	-	-
C1c - LCI Midstream	Midstream LED High Bay/Low Bay	E21C1c012	84	84	1,349.0	1,226.4	16,943.6	15,403.3	234.8	213.4	299.8	272.5	(292.6)	(266.0)	(3,674.5)	(3,340.5)
C1c - LCI Midstream	Midstream LED Linear Fixture	E21C1c013	150	150	297.9	270.8	3,273.4	2,975.9	34.1	31.0	43.6	39.6	(42.5)	(38.6)	(467.2)	(424.7)
C1c - LCI Midstream	Midstream LED Linear Fixture with Controls	E21C1c014	8	8	33.2	30.2	365.0	331.8	1.9	1.7	2.4	2.2	(4.7)	(4.3)	(52.1)	(47.4)
C1c - LCI Midstream	Midstream LED Linear Lamp	E21C1c015	45	45	244.1	221.9	2,570.6	2,336.9	28.0	25.4	35.7	32.5	(34.8)	(31.7)	(366.9)	(333.6)
C1c - LCI Midstream	Midstream LED Screw In	E21C1c016	66	66	256.6	215.9	1,203.6	1,012.6	14.7	12.4	21.0	17.7	(49.3)	(41.5)	(231.3)	(194.6)
C1c - LCI Midstream	Midstream LED Stairwell Kit	E21C1c017	6	6	5.1	4.6	51.1	46.4	0.8	0.8	0.8	0.8	-	-	-	-
C1c - LCI Midstream	Midstream Combination Oven, Electric	E21C1c018	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Convection Oven, Electric	E21C1c019	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Conveyor Broiler	E21C1c047	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Deck Oven, Electric	E21C1c050	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C1c020	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Multi Tank Conveyo	E21C1c021	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Pot, Pan, Utensil	E21C1c022	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Single Tank Conve	E21C1c023	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Under Counter	E21C1c024	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C1c025	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Multi Tank Conveyo	E21C1c026	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Single Tank Convey	E21C1c027	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Under Counter	E21C1c028	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Solid Door	E21C1c029	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Glass Door	E21C1c030	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Large Vat, Electric	E21C1c031	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Standard Vat, Electric	E21C1c032	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Griddle, Electric	E21C1c033	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hand-Wrap Machine	E21C1c051	-	-									-	-	-	-
C1c - LCI Midstream	Midstream High Efficiency Condensing Unit	E21C1c052	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C1c034	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C1c035	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C1c036	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Ice Making Head	E21C1c037	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Batch	E21C1c038	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Continu	E21C1c039	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Self Contained	E21C1c040	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerated Chef Base	E21C1c053	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Glass Door	E21C1c041	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Solid Door	E21C1c042	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Steam Cooker, Electric	E21C1c043	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ultra Low-Temp Freezer	E21C1c048	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 120 gallons	E21C1c044	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 50 gallons	E21C1c045	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 80 gallons	E21C1c046	-	-									-	-	-	-
			-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Compressed Air Direct Install	E21C1d001	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Hot Water Direct Install	E21C1d002	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large HVAC Direct Install	E21C1d003	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Interior	E21C1d004	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Exterior	E21C1d005	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Controls	E21C1d006	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Motors Direct Install	E21C1d007	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Process Direct Install	E21C1d008	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Refrigeration Direct Install	E21C1d009	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Other Direct Install	E21C1d010	-	-									-	-	-	-
C1d - LCI Direct Install	Daylight Dimming	E21C1d011	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C1d012	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C1d013	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C1d014	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C1d015	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1d - LCI Direct Install	Lighting Occupancy Sensors	E21C1d016	-	-									-	-	-	-
C1d - LCI Direct Install	Boiler Reset Controls, Electric	E21C1d017	-	-									-	-	-	-
C1d - LCI Direct Install	Case Motor Replacement	E21C1d018	-	-									-	-	-	-
C1d - LCI Direct Install	Cooler Night Cover	E21C1d019	-	-									-	-	-	-
C1d - LCI Direct Install	Demand Control Ventilation	E21C1d020	-	-									-	-	-	-
C1d - LCI Direct Install	Door Heater Controls	E21C1d021	-	-									-	-	-	-
C1d - LCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C1d022	-	-									-	-	-	-
C1d - LCI Direct Install	Duct Sealing, Electric	E21C1d023	-	-									-	-	-	-
C1d - LCI Direct Install	Ductless Mini Split Heat Pump	E21C1d024	-	-									-	-	-	-
C1d - LCI Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C1d025	-	-									-	-	-	-
C1d - LCI Direct Install	Electronic Defrost Control	E21C1d026	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Management System, Electric	E21C1d027	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C1d028	-	-									-	-	-	-
C1d - LCI Direct Install	Evaporator Fan Control	E21C1d029	-	-									-	-	-	-
C1d - LCI Direct Install	Faucet Aerator, Electric	E21C1d030	-	-									-	-	-	-
C1d - LCI Direct Install	Hotel Occupancy Sensor	E21C1d031	-	-									-	-	-	-
C1d - LCI Direct Install	Low Pressure Drop Filter	E21C1d032	-	-									-	-	-	-
C1d - LCI Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C1d033	-	-									-	-	-	-
C1d - LCI Direct Install	Low-Flow Showerhead, Electric	E21C1d034	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Open Drip	E21C1d035	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C1d036	-	-									-	-	-	-
C1d - LCI Direct Install	Novelty Cooler Shutoff	E21C1d037	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Heating, Electric	E21C1d038	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C1d039	-	-									-	-	-	-
C1d - LCI Direct Install	Pre Rinse Spray Valve, Electric	E21C1d040	-	-									-	-	-	-
C1d - LCI Direct Install	Programmable Thermostat, Electric	E21C1d041	-	-									-	-	-	-
C1d - LCI Direct Install	Steam Trap, Electric	E21C1d042	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive	E21C1d043	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive with Motor	E21C1d044	-	-									-	-	-	-
C1d - LCI Direct Install	Vending Miser	E21C1d045	-	-									-	-	-	-
C1d - LCI Direct Install	Zero Loss Condensate Drain	E21C1d046	-	-									-	-	-	-
	Large Business Energy Solutions Subtotal				**20,718.7**	**19,355.4**	**252,273.8**	**236,358.5**	**2,312.6**	**2,121.5**	**2,733.0**	**2,512.3**	**(5,792.8)**	**(5,301.0)**	**(62,497.2)**	**(57,230.3)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2a - SCI Retrofit	Custom Small Compressed Air Retro	E21C2a001	3	3	49.2	47.7	695.6	674.7	5.5	5.3	5.5	5.3	-	-	-	-
C2a - SCI Retrofit	Custom Small Hot Water Retro	E21C2a002	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small HVAC Retro	E21C2a003	3	3	7.1	6.9	92.9	90.1	1.0	1.0	0.9	0.8	-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Interior	E21C2a004	109	107	2,538.7	2,348.2	27,245.7	25,200.8	290.5	268.7	381.0	352.4	(1,431.7)	(1,324.2)	(15,365.2)	(14,212.0)
C2a - SCI Retrofit	Custom Small Lighting Retro - Exterior	E21C2a047	19	18	139.6	127.8	1,421.3	1,301.2	27.2	24.9	-	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Controls	E21C2a048	18	18	120.9	111.8	1,087.7	1,006.0	1.6	1.5	1.8	1.7	(429.0)	(396.8)	(3,860.8)	(3,571.0)
C2a - SCI Retrofit	Custom Small Motors Retro	E21C2a005	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Process Retro	E21C2a006	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Refrigeration Retro	E21C2a007	1	1	7.2	7.0	94.2	91.3	0.8	0.8	0.7	0.7	-	-	-	-
C2a - SCI Retrofit	Custom Small Other Retro	E21C2a008	-	-									-	-	-	-
C2a - SCI Retrofit	Daylight Dimming	E21C2a009	-	-									-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C2a010	1	1	20.5	18.8	184.8	169.2	4.0	3.7	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C2a011	8	8	433.0	400.5	4,408.2	4,077.4	84.3	78.0	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C2a012	5	4	46.1	42.2	414.8	379.8	3.4	3.1	4.9	4.5	(29.9)	(27.4)	(268.9)	(246.2)
C2a - SCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C2a013	707	693	1,807.6	1,672.0	19,399.7	17,943.7	131.9	122.0	194.0	179.4	(1,171.7)	(1,083.8)	(12,575.2)	(11,631.4)
C2a - SCI Retrofit	Lighting Occupancy Sensors	E21C2a014	5	5	0.3	0.3	3.0	2.7	0.0	0.0	0.0	0.0	(1.3)	(1.2)	(12.1)	(11.0)
C2a - SCI Retrofit	Boiler Reset Controls, Electric	E21C2a015	-	-									-	-	-	-
C2a - SCI Retrofit	Case Motor Replacement	E21C2a016	-	-									-	-	-	-
C2a - SCI Retrofit	Cooler Night Cover	E21C2a017	-	-									-	-	-	-
C2a - SCI Retrofit	Demand Control Ventilation	E21C2a018	-	-									-	-	-	-
C2a - SCI Retrofit	Door Heater Controls	E21C2a019	-	-									-	-	-	-
C2a - SCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C2a020	-	-									-	-	-	-
C2a - SCI Retrofit	Duct Sealing, Electric	E21C2a021	-	-									-	-	-	-
C2a - SCI Retrofit	Ductless Mini Split Heat Pump	E21C2a022	-	-									-	-	-	-
C2a - SCI Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C2a023	-	-									-	-	-	-
C2a - SCI Retrofit	Electronic Defrost Control	E21C2a024	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Management System, Electric	E21C2a025	2	2	23.9	23.4	239.1	234.3	2.4	-	2.3	-	-	-	-	-
C2a - SCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C2a026	-	-									-	-	-	-
C2a - SCI Retrofit	Evaporator Fan Control	E21C2a027	-	-									-	-	-	-
C2a - SCI Retrofit	Faucet Aerator, Electric	E21C2a028	-	-									-	-	-	-
C2a - SCI Retrofit	Hotel Occupancy Sensor	E21C2a031	-	-									-	-	-	-
C2a - SCI Retrofit	Low Pressure Drop Filter	E21C2a032	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electric	E21C2a033	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead, Electric	E21C2a034	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Open Drip	E21C2a035	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C2a036	-	-									-	-	-	-
C2a - SCI Retrofit	Novelty Cooler Shutoff	E21C2a037	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Heating, Electric	E21C2a038	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C2a039	-	-									-	-	-	-
C2a - SCI Retrofit	Pre Rinse Spray Valve, Electric	E21C2a040	-	-									-	-	-	-
C2a - SCI Retrofit	Programmable Thermostat, Electric	E21C2a041	-	-									-	-	-	-
C2a - SCI Retrofit	Steam Trap, Electric	E21C2a042	-	-									-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive	E21C2a043	3	3	94.9	93.0	1,424.0	1,395.5	5.6	5.4	5.0	4.9	-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive with Motor	E21C2a044	-	-									-	-	-	-
C2a - SCI Retrofit	Vending Miser	E21C2a045	-	-									-	-	-	-
C2a - SCI Retrofit	Zero Loss Condensate Drain	E21C2a046	-	-									-	-	-	-
C2a - SCI Retrofit	Small Retrocommissioning	E21C2a049	-	-									-	-	-	-
			-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Compressed Air New	E21C2b001	1	1	27.7	27.2	415.7	407.4	-	-	-	-	-	-	-	-
C2b - SCI New Equipment	Custom Small Hot Water New	E21C2b002	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small HVAC New	E21C2b003	38	37	358.0	350.9	4,683.0	4,589.4	23.7	23.3	61.6	60.4	-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Interior	E21C2b004	46	45	722.2	668.0	10,832.4	10,019.4	82.6	76.4	108.4	100.3	(95.6)	(88.5)	(1,434.7)	(1,327.0)
C2b - SCI New Equipment	Custom Small Lighting New - Exterior	E21C2b054	20	20	252.5	233.5	3,787.2	3,502.9	49.2	45.5	-	-	-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Controls	E21C2b055	30	29	18.1	16.8	181.4	167.8	0.2	0.2	0.3	0.3	(64.4)	(59.6)	(643.9)	(595.6)
C2b - SCI New Equipment	Custom Small Motors New	E21C2b005	2	2	34.6	33.9	518.6	508.2	4.5	4.4	5.4	5.3	-	-	-	-
C2b - SCI New Equipment	Custom Small Process New	E21C2b006	4	4	77.1	75.5	1,156.1	1,133.0	5.6	5.5	11.9	11.6	-	-	-	-
C2b - SCI New Equipment	Custom Small Refrigeration New	E21C2b007	1	1	154.3	151.2	2,313.8	2,267.6	15.7	15.4	15.7	15.4	-	-	-	-
C2b - SCI New Equipment	Custom Small Other New	E21C2b008	11	11	270.6	265.1	3,955.9	3,876.8	12.9	12.6	14.3	14.0	-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Custom Small Comprehensive Design	E21C2b056	-	-									-	-	-	-
C2b - SCI New Equipment	Daylight Dimming	E21C2b009	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C2b010	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C2b011	13	13	86.7	80.2	1,300.7	1,203.0	16.9	15.6	-	-	-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/ Controls	E21C2b012	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/o Controls	E21C2b013	386	378	779.0	720.5	11,684.6	10,807.6	56.9	52.6	83.6	77.3	(118.6)	(109.7)	(1,778.8)	(1,645.3)
C2b - SCI New Equipment	Lighting Occupancy Sensors	E21C2b014	1	1	1.2	1.1	11.7	10.8	0.0	0.0	0.0	0.0	(4.8)	(4.4)	(47.5)	(44.0)
C2b - SCI New Equipment	Advanced Power Strip	E21C2b015	-	-									-	-	-	-
C2b - SCI New Equipment	Air Compressor	E21C2b016	2	2	56.8	55.7	851.9	834.9	5.6	5.5	6.6	6.5	-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Air Nozzle	E21C2b017	-	-									-	-	-	-
C2b - SCI New Equipment	Circulator Pump	E21C2b018	-	-									-	-	-	-
C2b - SCI New Equipment	Combination Oven, Electric	E21C2b019	-	-									-	-	-	-
C2b - SCI New Equipment	Compressor Storage	E21C2b020	-	-									-	-	-	-
C2b - SCI New Equipment	Convection Oven, Electric	E21C2b021	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Door Type	E21C2b022	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C2b023	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C2b024	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Single Tank Conveyor	E21C2b025	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Under Counter	E21C2b026	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Door Type	E21C2b027	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C2b028	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Single Tank Conveyor	E21C2b029	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Under Counter	E21C2b030	-	-									-	-	-	-
C2b - SCI New Equipment	Faucet Aerator, Electric	E21C2b031	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Large Vat, Electric	E21C2b032	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Standard Vat, Electric	E21C2b033	-	-									-	-	-	-
C2b - SCI New Equipment	Griddle, Electric	E21C2b034	-	-									-	-	-	-
C2b - SCI New Equipment	Ground Source Heat Pump	E21C2b035	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C2b036	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Full Size	E21C2b037	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Half Size	E21C2b038	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Ice Making Head	E21C2b039	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C2b040	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Continuous	E21C2b041	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Self Contained	E21C2b042	-	-									-	-	-	-
C2b - SCI New Equipment	Low Pressure Drop Filter	E21C2b043	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C2b044	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead, Electric	E21C2b045	-	-									-	-	-	-
C2b - SCI New Equipment	Pre Rinse Spray Valve, Electric	E21C2b046	-	-									-	-	-	-
C2b - SCI New Equipment	Refrigerated Air Dryer	E21C2b047	-	-									-	-	-	-
C2b - SCI New Equipment	Steam Cooker, Electric	E21C2b048	-	-									-	-	-	-
C2b - SCI New Equipment	Unitary Air Conditioner	E21C2b049	7	7	53.6	53.1	643.4	637.0	-	-	3.7	3.6	-	-	-	-
C2b - SCI New Equipment	Water Source Heat Pump	E21C2b050	-	-									-	-	-	-
C2b - SCI New Equipment	Zero Loss Condensate Drain	E21C2b051	-	-									-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - FL	E21C2b052	4	4	1.9	1.9	43.4	43.0	0.1	0.1	1.0	1.0	-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - IPLV	E21C2b053	-	-									-	-	-	-
C2b - SCI New Equipment	C&I Small New Construction Code Compliance	E21C2b057	-	-									-	-	-	-
			-	-									-	-	-	-
C2c - SCI Midstream	Midstream Circulator Pump	E21C2c001	12	12	14.4	14.4	287.2	287.2	0.1	0.1	2.4	2.4	-	-	-	-
C2c - SCI Midstream	Midstream Demand Control Ventilation	E21C2c002		-									-	-	-	-
C2c - SCI Midstream	Midstream DMSHP Systems	E21C2c003	14	14	14.9	14.9	179.1	179.1	-	-	3.1	3.1	-	-	-	-
C2c - SCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C2c004	8	8	57.4	57.4	573.7	573.7	-	-	19.6	19.6	-	-	-	-
C2c - SCI Midstream	Midstream ECM Fan Motors	E21C2c005		-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Systems	E21C2c006		-									-	-	-	-
C2c - SCI Midstream	Midstream Unitary Air Conditioners	E21C2c007	58	58	213.5	213.5	2,562.3	2,562.3	-	-	14.6	14.6	-	-	-	-
C2c - SCI Midstream	Midstream VRF	E21C2c008	38	38	391.1	391.1	4,693.7	4,693.7	-	-	26.8	26.8	-	-	-	-
C2c - SCI Midstream	Midstream Water Source Heat Pump Systems	E21C2c009	2	2	0.8	0.8	20.5	20.5	-	-	0.2	0.2	-	-	-	-
C2c - SCI Midstream	Midstream LED Downlight	E21C2c010	149	149	507.1	461.0	2,971.3	2,701.2	39.2	35.7	56.0	50.9	(131.7)	(119.7)	(771.6)	(701.4)
C2c - SCI Midstream	Midstream LED Exterior	E21C2c011	447	447	1,050.5	955.0	10,231.6	9,301.5	212.4	193.1	-	-	-	-	-	-
C2c - SCI Midstream	Midstream LED High Bay/Low Bay	E21C2c012	972	972	8,250.2	7,500.2	103,622.6	94,202.4	1,435.8	1,305.3	1,833.4	1,666.7	(1,789.2)	(1,626.5)	(22,472.4)	(20,429.4)
C2c - SCI Midstream	Midstream LED Linear Fixture	E21C2c013	871	871	1,335.2	1,213.8	14,673.3	13,339.4	152.9	139.0	195.3	177.5	(190.6)	(173.2)	(2,094.3)	(1,904.0)
C2c - SCI Midstream	Midstream LED Linear Fixture with Controls	E21C2c014	3	3	5.3	4.8	58.0	52.7	0.3	0.3	0.4	0.4	(0.8)	(0.7)	(8.3)	(7.5)
C2c - SCI Midstream	Midstream LED Linear Lamp	E21C2c015	153	153	608.0	552.7	6,402.5	5,820.4	69.6	63.3	88.9	80.8	(86.8)	(78.9)	(913.8)	(830.8)
C2c - SCI Midstream	Midstream LED Screw In	E21C2c016	164	164	761.3	640.5	3,570.7	3,003.9	43.6	36.7	62.3	52.4	(146.3)	(123.1)	(686.2)	(577.3)
C2c - SCI Midstream	Midstream LED Stairwell Kit	E21C2c017	19	19	12.1	11.0	120.8	109.8	2.0	1.8	2.0	1.8	-	-	-	-
C2c - SCI Midstream	Midstream Combination Oven, Electric	E21C2c018	6	6	77.9	77.9	934.7	934.7	16.3	16.3	16.3	16.3	-	-	-	-
C2c - SCI Midstream	Midstream Convection Oven, Electric	E21C2c019	5	5	12.0	12.0	143.8	143.8	2.7	2.7	2.7	2.7	-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream Conveyor Broiler	E21C2c047	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Deck Oven, Electric	E21C2c050	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C2c020	2	2	7.1	7.1	107.1	107.1	1.1	1.1	1.1	1.1	-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Multi Tank Conveyo	E21C2c021	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Pot, Pan, Utensil	E21C2c022	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Single Tank Conve	E21C2c023	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Under Counter	E21C2c024	9	9	13.9	13.9	138.6	138.6	2.2	2.2	2.2	2.2	-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C2c025	1	1	11.9	11.9	178.7	178.7	1.9	1.9	1.9	1.9	-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Multi Tank Conveyo	E21C2c026	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Single Tank Convey	E21C2c027	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Under Counter	E21C2c028	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Solid Door	E21C2c029	18	18	3.3	3.3	39.4	39.4	0.3	0.3	0.3	0.3	-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Glass Door	E21C2c030	4	4	1.5	1.5	17.6	17.6	0.2	0.2	0.2	0.2	-	-	-	-
C2c - SCI Midstream	Midstream Fryer Large Vat, Electric	E21C2c031	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Fryer Standard Vat, Electric	E21C2c032	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Griddle, Electric	E21C2c033	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hand-Wrap Machine	E21C2c051	-	-									-	-	-	-
C2c - SCI Midstream	Midstream High Efficiency Condensing Unit	E21C2c052	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C2c034	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C2c035	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C2c036	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Ice Making Head	E21C2c037	15	15	14.4	14.4	115.3	115.3	3.5	3.5	3.5	3.5	-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Batch	E21C2c038	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Continu	E21C2c039	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Self Contained	E21C2c040	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerated Chef Base	E21C2c053	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Glass Door	E21C2c041	9	9	1.9	1.9	22.8	22.8	0.2	0.2	0.2	0.2	-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Solid Door	E21C2c042	37	37	5.4	5.4	64.9	64.9	0.6	0.6	0.6	0.6	-	-	-	-
C2c - SCI Midstream	Midstream Steam Cooker, Electric	E21C2c043	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ultra Low-Temp Freezer	E21C2c048	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 120 gallons	E21C2c044	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 50 gallons	E21C2c045	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 80 gallons	E21C2c046	-	-									-	-	-	-
			-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Compressed Air Direct Install	E21C2d001	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Hot Water Direct Install	E21C2d002	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small HVAC Direct Install	E21C2d003	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Interior	E21C2d004	1,049	1,028	3,582.6	3,313.7	38,448.3	35,562.5	410.0	379.2	537.7	497.4	(11,929.3)	(11,033.9)	(128,026.2)	(118,417.1)
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Exterior	E21C2d005	165	162	478.8	442.9	4,874.6	4,508.7	93.2	86.3	-	-	-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Controls	E21C2d006	41	41	59.2	54.7	532.4	492.5	0.8	0.7	0.9	0.8	(210.0)	(194.2)	(1,889.9)	(1,748.1)
C2d - SCI Direct Install	Custom Small Motors Direct Install	E21C2d007	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Process Direct Install	E21C2d008	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Refrigeration Direct Install	E21C2d009	10	10	67.4	66.0	710.7	854.7	7.4	7.3	6.7	6.6	-	-	-	-
C2d - SCI Direct Install	Custom Small Other Direct Install	E21C2d010	6	6	7.3	7.2	73.1	93.1	0.3	0.3	0.4	0.4	-	-	-	-
C2d - SCI Direct Install	Daylight Dimming	E21C2d011	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C2d012	2	2	2.9	2.7	26.0	24.1	0.6	0.5	-	-	-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C2d013	10	10	195.2	180.6	1,987.6	1,838.4	38.0	35.2	-	-	-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C2d014	24	24	225.5	208.6	2,029.3	1,877.0	16.5	15.2	24.2	22.4	(863.0)	(798.2)	(7,766.8)	(7,183.9)
C2d - SCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C2d015	24	24	304.0	281.2	3,263.0	3,018.1	22.2	20.5	32.6	30.2	(1,163.7)	(1,076.3)	(12,488.7)	(11,551.3)
C2d - SCI Direct Install	Lighting Occupancy Sensors	E21C2d016	-	-									-	-	-	-
C2d - SCI Direct Install	Boiler Reset Controls, Electric	E21C2d017	-	-									-	-	-	-
C2d - SCI Direct Install	Case Motor Replacement	E21C2d018	-	-									-	-	-	-
C2d - SCI Direct Install	Cooler Night Cover	E21C2d019	-	-									-	-	-	-
C2d - SCI Direct Install	Demand Control Ventilation	E21C2d020	-	-									-	-	-	-
C2d - SCI Direct Install	Door Heater Controls	E21C2d021	-	-									-	-	-	-
C2d - SCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C2d022	-	-									-	-	-	-
C2d - SCI Direct Install	Duct Sealing, Electric	E21C2d023	-	-									-	-	-	-
C2d - SCI Direct Install	Ductless Mini Split Heat Pump	E21C2d024	-	-									-	-	-	-
C2d - SCI Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C2d025	-	-									-	-	-	-
C2d - SCI Direct Install	Electronic Defrost Control	E21C2d026	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Management System, Electric	E21C2d027	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C2d028	-	-									-	-	-	-
C2d - SCI Direct Install	Evaporator Fan Control	E21C2d029	-	-									-	-	-	-
C2d - SCI Direct Install	Faucet Aerator, Electric	E21C2d030	-	-									-	-	-	-
C2d - SCI Direct Install	Hotel Occupancy Sensor	E21C2d031	-	-									-	-	-	-
C2d - SCI Direct Install	Low Pressure Drop Filter	E21C2d032	-	-									-	-	-	-
C2d - SCI Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C2d033	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2d - SCI Direct Install	Low-Flow Showerhead, Electric	E21C2d034	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Open Drip	E21C2d035	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C2d036	-	-									-	-	-	-
C2d - SCI Direct Install	Novelty Cooler Shutoff	E21C2d037	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Heating, Electric	E21C2d038	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C2d039	-	-									-	-	-	-
C2d - SCI Direct Install	Pre Rinse Spray Valve, Electric	E21C2d040	-	-									-	-	-	-
C2d - SCI Direct Install	Programmable Thermostat, Electric	E21C2d041	-	-									-	-	-	-
C2d - SCI Direct Install	Steam Trap, Electric	E21C2d042	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive	E21C2d043	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive with Motor	E21C2d044	-	-									-	-	-	-
C2d - SCI Direct Install	Vending Miser	E21C2d045	-	-									-	-	-	-
C2d - SCI Direct Install	Zero Loss Condensate Drain	E21C2d046	-	-									-	-	-	-
	Small Business Energy Solutions Subtotal				**26,477.2**	**24,371.9**	**302,766.0**	**279,455.1**	**3,406.1**	**3,121.0**	**3,844.9**	**3,529.3**	**(19,858.2)**	**(18,320.4)**	**(213,105.3)**	**(196,634.1)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Custom Muni Compressed Air Retro	E21C3a001	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Hot Water Retro	E21C3a002	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni HVAC Retro	E21C3a003	2	2	31.4	30.4	297.5	288.6	3.0	2.9	2.4	2.4	501.4	476.7	4,756.9	4,521.9
C3a - Muni Retrofit	Custom Muni Lighting Retro - Interior	E21C3a004	15	14	522.6	478.5	5,609.0	5,135.1	59.8	54.8	78.4	71.8	(294.7)	(269.8)	(3,163.2)	(2,895.9)
C3a - Muni Retrofit	Custom Muni Lighting Retro - Exterior	E21C3a091	11	11	158.2	147.9	1,610.9	1,505.2	30.8	28.8	-	-	-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Controls	E21C3a092	6	6	16.8	15.7	150.9	141.0	0.2	0.2	0.3	0.2	(59.5)	(55.6)	(535.7)	(500.5)
C3a - Muni Retrofit	Custom Muni Motors Retro	E21C3a005	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Process Retro	E21C3a006	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Refrigeration Retro	E21C3a007	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Other Retro	E21C3a008	4	4	0.7	0.7	17.0	16.9	0.1	0.1	0.1	0.1	-	-	-	-
C3a - Muni Retrofit	Daylight Dimming	E21C3a009	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/ Controls	E21C3a010	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/o Controls	E21C3a011	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Interior w/ Controls	E21C3a012	2	2	131.4	122.8	1,182.5	1,104.9	9.6	9.0	14.1	13.2	(85.2)	(79.6)	(766.5)	(716.2)
C3a - Muni Retrofit	Lighting Fixture - Interior w/o Controls	E21C3a013	7	7	279.5	261.2	3,000.1	2,803.2	20.4	19.1	30.0	28.0	(181.2)	(169.3)	(1,944.7)	(1,817.1)
C3a - Muni Retrofit	Lighting Occupancy Sensors	E21C3a014	5	5	128.1	119.7	1,153.0	1,077.3	1.7	1.6	2.3	2.2	(522.7)	(488.4)	(4,704.1)	(4,395.4)
C3a - Muni Retrofit	Air Sealing, Electric	E21C3a015	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Gas	E21C3a016	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Oil	E21C3a017	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Propane	E21C3a018	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Gas	E21C3a019	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Oil	E21C3a020	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Propane	E21C3a021	-	-									-	-	-	-
C3a - Muni Retrofit	Case Motor Replacement	E21C3a022	-	-									-	-	-	-
C3a - Muni Retrofit	Cooler Night Cover	E21C3a023	-	-									-	-	-	-
C3a - Muni Retrofit	Demand Control Ventilation	E21C3a024	-	-									-	-	-	-
C3a - Muni Retrofit	Door Heater Controls	E21C3a025	-	-									-	-	-	-
C3a - Muni Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C3a026	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Electric	E21C3a027	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Gas	E21C3a028	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Oil	E21C3a029	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Propane	E21C3a030	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Electric	E21C3a031	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Gas	E21C3a032	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Oil	E21C3a033	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Propane	E21C3a034	-	-									-	-	-	-
C3a - Muni Retrofit	Ductless Mini Split Heat Pump	E21C3a035	-	-									-	-	-	-
C3a - Muni Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C3a036	-	-									-	-	-	-
C3a - Muni Retrofit	Electronic Defrost Control	E21C3a037	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Management System, Electric	E21C3a038	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Electric	E21C3a039	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Gas	E21C3a040	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Oil	E21C3a041	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Propane	E21C3a042	-	-									-	-	-	-
C3a - Muni Retrofit	Evaporator Fan Control	E21C3a043	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Electric	E21C3a044	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Gas	E21C3a045	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Oil	E21C3a046	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Propane	E21C3a047	-	-									-	-	-	-
C3a - Muni Retrofit	Hotel Occupancy Sensor	E21C3a050	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Electric	E21C3a051	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Gas	E21C3a052	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Oil	E21C3a053	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Propane	E21C3a054	-	-									-	-	-	-
C3a - Muni Retrofit	Low Pressure Drop Filter	E21C3a055	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electric	E21C3a056	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3a057	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3a058	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3a059	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Electric	E21C3a060	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Gas	E21C3a061	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Oil	E21C3a062	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Propane	E21C3a063	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Open Drip	E21C3a064	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Totally Enclosed Fan Cooled	E21C3a065	-	-									-	-	-	-
C3a - Muni Retrofit	Novelty Cooler Shutoff	E21C3a066	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Electric	E21C3a067	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Gas	E21C3a068	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Oil	E21C3a069	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Propane	E21C3a070	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Electric	E21C3a071	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Gas	E21C3a072	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Oil	E21C3a073	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Propane	E21C3a074	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Electric	E21C3a075	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Gas	E21C3a076	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Oil	E21C3a077	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Propane	E21C3a078	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Electric	E21C3a079	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Gas	E21C3a080	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Oil	E21C3a081	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Propane	E21C3a082	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Electric	E21C3a083	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Gas	E21C3a084	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Oil	E21C3a085	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Propane	E21C3a086	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive	E21C3a087	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive with Motor	E21C3a088	-	-									-	-	-	-
C3a - Muni Retrofit	Vending Miser	E21C3a089	-	-									-	-	-	-
C3a - Muni Retrofit	Zero Loss Condensate Drain	E21C3a090	-	-									-	-	-	-
			-	-									-	-	-	-
C3b - Muni New Equipment	Custom Muni Compressed Air New	E21C3b001	-	-									-	-	-	-
C3b - Muni New Equipment	Custom Muni Hot Water New	E21C3b002	6	6	6.3	6.3	94.9	93.9	-	-	-	-	45.4	44.1	681.4	661.1
C3b - Muni New Equipment	Custom Muni HVAC New	E21C3b003	46	46	166.9	165.3	2,398.0	2,374.0	7.1	7.1	18.5	18.4	182.3	176.9	2,619.6	2,541.5
C3b - Muni New Equipment	Custom Muni Lighting New - Interior	E21C3b004	20	19	501.2	468.3	7,518.4	7,025.1	57.4	53.6	75.2	70.3	(66.4)	(62.0)	(995.8)	(930.4)
C3b - Muni New Equipment	Custom Muni Lighting New - Exterior	E21C3b085	13	13	118.2	110.5	1,773.3	1,656.9	23.0	21.5	-	-	-	-	-	-
C3b - Muni New Equipment	Custom Muni Lighting New - Controls	E21C3b086	1	1	0.1	0.1	1.1	1.1	0.0	0.0	0.0	0.0	(0.4)	(0.4)	(4.0)	(3.7)
C3b - Muni New Equipment	Custom Muni Motors New	E21C3b005	2	2	11.0	10.8	164.4	162.7	1.0	1.0	1.2	1.1	-	-	-	-
C3b - Muni New Equipment	Custom Muni Process New	E21C3b006	7	7	514.4	509.2	7,548.0	7,472.5	25.7	25.5	54.3	53.8	-	-	-	-
C3b - Muni New Equipment	Custom Muni Refrigeration New	E21C3b007	-	-									-	-	-	-
C3b - Muni New Equipment	Custom Muni Other New	E21C3b008	26	25	291.1	288.2	4,764.8	4,717.1	13.8	13.7	15.4	15.2	-	-	-	-
C3b - Muni New Equipment	Custom Muni Comprehensive Design	E21C3b087	-	-									-	-	-	-
C3b - Muni New Equipment	Daylight Dimming	E21C3b009	-	-									-	-	-	-
C3b - Muni New Equipment	Performance Lighting - Exterior w/ Controls	E21C3b010	-	-									-	-	-	-
C3b - Muni New Equipment	Performance Lighting - Exterior w/o Controls	E21C3b011	-	-									-	-	-	-
C3b - Muni New Equipment	Performance Lighting - Interior w/ Controls	E21C3b012	-	-									-	-	-	-
C3b - Muni New Equipment	Performance Lighting - Interior w/o Controls	E21C3b013	-	-									-	-	-	-
C3b - Muni New Equipment	Lighting Occupancy Sensors	E21C3b014	-	-									-	-	-	-
C3b - Muni New Equipment	Advanced Power Strip	E21C3b015	-	-									-	-	-	-
C3b - Muni New Equipment	Air Compressor	E21C3b016	-	-									-	-	-	-
C3b - Muni New Equipment	Air Nozzle	E21C3b017	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 1000 to 1700 MBH 90 AFUE, Oil	E21C3b018	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 1000 to 1700 MBH 90 AFUE, Propane	E21C3b019	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 1701 to 2000 MBH 85 AFUE, Oil	E21C3b020	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 1701 to 2000 MBH 90 AFUE, Propane	E21C3b021	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 301 to 499 MBH 85 AFUE, Oil	E21C3b022	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipment	Boiler 301 to 499 MBH 90 AFUE, Propane	E21C3b023	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 500 to 999 MBH 85 AFUE, Oil	E21C3b024	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler 500 to 999 MBH 90 AFUE, Propane	E21C3b025	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler to 300 MBH 85 AFUE, Oil	E21C3b026	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler to 300 MBH 87 AFUE, Oil	E21C3b027	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler to 300 MBH 90 AFUE, Propane	E21C3b028	-	-									-	-	-	-
C3b - Muni New Equipment	Boiler to 300 MBH 95 AFUE, Propane	E21C3b029	-	-									-	-	-	-
C3b - Muni New Equipment	Circulator Pump	E21C3b030	-	-									-	-	-	-
C3b - Muni New Equipment	Combination Oven, Electric	E21C3b031	-	-									-	-	-	-
C3b - Muni New Equipment	Compressor Storage	E21C3b032	-	-									-	-	-	-
C3b - Muni New Equipment	Condensing Unit Heater up to 300 MBH, Oil	E21C3b033	-	-									-	-	-	-
C3b - Muni New Equipment	Condensing Unit Heater up to 300 MBH, Propane	E21C3b034	-	-									-	-	-	-
C3b - Muni New Equipment	Convection Oven, Electric	E21C3b035	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - High Temp Door Type	E21C3b036	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C3b037	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C3b038	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - High Temp Single Tank Conveyor	E21C3b039	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - High Temp Under Counter	E21C3b040	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - Low Temp Door Type	E21C3b041	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C3b042	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - Low Temp Single Tank Conveyor	E21C3b043	-	-									-	-	-	-
C3b - Muni New Equipment	Dishwasher - Low Temp Under Counter	E21C3b044	-	-									-	-	-	-
C3b - Muni New Equipment	Faucet Aerator, Electric	E21C3b045	-	-									-	-	-	-
C3b - Muni New Equipment	Faucet Aerator, Gas	E21C3b046	-	-									-	-	-	-
C3b - Muni New Equipment	Faucet Aerator, Oil	E21C3b047	-	-									-	-	-	-
C3b - Muni New Equipment	Faucet Aerator, Propane	E21C3b048	-	-									-	-	-	-
C3b - Muni New Equipment	Fryer Large Vat, Electric	E21C3b049	-	-									-	-	-	-
C3b - Muni New Equipment	Fryer Standard Vat, Electric	E21C3b050	-	-									-	-	-	-
C3b - Muni New Equipment	Furnace w/ ECM 85 AFUE up to 150 MBH, Oil	E21C3b051	-	-									-	-	-	-
C3b - Muni New Equipment	Furnace w/ ECM 87 AFUE up to 150 MBH, Oil	E21C3b052	-	-									-	-	-	-
C3b - Muni New Equipment	Furnace w/ ECM 95 AFUE up to 150 MBH, Propane	E21C3b053	-	-									-	-	-	-
C3b - Muni New Equipment	Furnace w/ ECM 97 AFUE up to 150 MBH, Propane	E21C3b054	-	-									-	-	-	-
C3b - Muni New Equipment	Griddle, Electric	E21C3b055	-	-									-	-	-	-
C3b - Muni New Equipment	Ground Source Heat Pump	E21C3b056	-	-									-	-	-	-
C3b - Muni New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C3b057	-	-									-	-	-	-
C3b - Muni New Equipment	Hot Food Holding Cabinet Full Size	E21C3b058	-	-									-	-	-	-
C3b - Muni New Equipment	Hot Food Holding Cabinet Half Size	E21C3b059	-	-									-	-	-	-
C3b - Muni New Equipment	Ice Machine - Ice Making Head	E21C3b060	-	-									-	-	-	-
C3b - Muni New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C3b061	-	-									-	-	-	-
C3b - Muni New Equipment	Ice Machine - Remote Cond./Split Unit - Continuous	E21C3b062	-	-									-	-	-	-
C3b - Muni New Equipment	Ice Machine - Self Contained	E21C3b063	-	-									-	-	-	-
C3b - Muni New Equipment	Infrared Heater	E21C3b064	-	-									-	-	-	-
C3b - Muni New Equipment	Low Pressure Drop Filter	E21C3b065	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C3b066	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3b067	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3b068	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3b069	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead, Electric	E21C3b070	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead, Gas	E21C3b071	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead, Oil	E21C3b072	-	-									-	-	-	-
C3b - Muni New Equipment	Low-Flow Showerhead, Propane	E21C3b073	-	-									-	-	-	-
C3b - Muni New Equipment	Pre Rinse Spray Valve, Electric	E21C3b074	-	-									-	-	-	-
C3b - Muni New Equipment	Pre Rinse Spray Valve, Gas	E21C3b075	-	-									-	-	-	-
C3b - Muni New Equipment	Pre Rinse Spray Valve, Oil	E21C3b076	-	-									-	-	-	-
C3b - Muni New Equipment	Pre Rinse Spray Valve, Propane	E21C3b077	-	-									-	-	-	-
C3b - Muni New Equipment	Refrigerated Air Dryer	E21C3b078	-	-									-	-	-	-
C3b - Muni New Equipment	Steam Cooker, Electric	E21C3b079	-	-									-	-	-	-
C3b - Muni New Equipment	Unitary Air Conditioner	E21C3b080	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipment	Water Source Heat Pump	E21C3b081	-	-									-	-	-	-
C3b - Muni New Equipment	Zero Loss Condensate Drain	E21C3b082	-	-									-	-	-	-
C3b - Muni New Equipment	High Efficiency Chiller - FL	E21C3b083	-	-									-	-	-	-
C3b - Muni New Equipment	High Efficiency Chiller - IPLV	E21C3b084	-	-									-	-	-	-
			-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Compressed Air Direct Install	E21C3d001	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Hot Water Direct Install	E21C3d002	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni HVAC Direct Install	E21C3d003	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Interior	E21C3d004	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Exterior	E21C3d005	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Controls	E21C3d006	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Motors Direct Install	E21C3d007	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Process Direct Install	E21C3d008	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Refrigeration Direct Install	E21C3d009	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Other Direct Install	E21C3d010	-	-									-	-	-	-
C3d - Muni Direct Install	Daylight Dimming	E21C3d011	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/ Controls	E21C3d012	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/o Controls	E21C3d013	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Interior w/ Controls	E21C3d014	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Interior w/o Controls	E21C3d015	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Occupancy Sensors	E21C3d016	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Electric	E21C3d017	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Gas	E21C3d018	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Oil	E21C3d019	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Propane	E21C3d020	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Gas	E21C3d021	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Boiler Reset Controls, Oil	E21C3d022	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Propane	E21C3d023	-	-									-	-	-	-
C3d - Muni Direct Install	Case Motor Replacement	E21C3d024	-	-									-	-	-	-
C3d - Muni Direct Install	Cooler Night Cover	E21C3d025	-	-									-	-	-	-
C3d - Muni Direct Install	Demand Control Ventilation	E21C3d026	-	-									-	-	-	-
C3d - Muni Direct Install	Door Heater Controls	E21C3d027	-	-									-	-	-	-
C3d - Muni Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C3d028	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Electric	E21C3d029	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Gas	E21C3d030	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Oil	E21C3d031	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Propane	E21C3d032	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Electric	E21C3d033	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Gas	E21C3d034	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Oil	E21C3d035	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Propane	E21C3d036	-	-									-	-	-	-
C3d - Muni Direct Install	Ductless Mini Split Heat Pump	E21C3d037	-	-									-	-	-	-
C3d - Muni Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freezer	E21C3d038	-	-									-	-	-	-
C3d - Muni Direct Install	Electronic Defrost Control	E21C3d039	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Management System, Electric	E21C3d040	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Electric	E21C3d041	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Gas	E21C3d042	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Oil	E21C3d043	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Propane	E21C3d044	-	-									-	-	-	-
C3d - Muni Direct Install	Evaporator Fan Control	E21C3d045	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Electric	E21C3d046	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Gas	E21C3d047	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Oil	E21C3d048	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Propane	E21C3d049	-	-									-	-	-	-
C3d - Muni Direct Install	Hotel Occupancy Sensor	E21C3d050	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Electric	E21C3d051	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Gas	E21C3d052	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Oil	E21C3d053	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Propane	E21C3d054	-	-									-	-	-	-
C3d - Muni Direct Install	Low Pressure Drop Filter	E21C3d055	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electri	E21C3d056	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3d057	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3d058	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3d059	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Electric	E21C3d060	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Gas	E21C3d061	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Oil	E21C3d062	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Propane	E21C3d063	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Open Drip	E21C3d064	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Totally Enclosed Fan Cooled	E21C3d065	-	-									-	-	-	-
C3d - Muni Direct Install	Novelty Cooler Shutoff	E21C3d066	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Electric	E21C3d067	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Gas	E21C3d068	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Oil	E21C3d069	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Propane	E21C3d070	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Electric	E21C3d071	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Gas	E21C3d072	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Oil	E21C3d073	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Propane	E21C3d074	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Electric	E21C3d075	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Gas	E21C3d076	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Oil	E21C3d077	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Propane	E21C3d078	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Electric	E21C3d079	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Programmable Thermostat, Gas	E21C3d080	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Oil	E21C3d081	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Propane	E21C3d082	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Electric	E21C3d083	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Gas	E21C3d084	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Oil	E21C3d085	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Propane	E21C3d086	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive	E21C3d087	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive with Motor	E21C3d088	-	-									-	-	-	-
C3d - Muni Direct Install	Vending Miser	E21C3d089	-	-									-	-	-	-
C3d - Muni Direct Install	Zero Loss Condensate Drain	E21C3d090	-	-									-	-	-	-
	Municipal Energy Solutions Subtotal				**2,878.0**	**2,735.5**	**37,283.8**	**35,575.6**	**253.6**	**238.6**	**292.3**	**276.7**	**(480.9)**	**(427.5)**	**(4,056.0)**	**(3,534.8)**

PSNH d/b/a Eversource Energy
2022-2023 System Benefits Charge ("SBC") Calculation
($ in 000's)

Year	EE Total Budget	RSA 125-O:5-a Funding	RGGI Revenues	FCM Revenues	Other Revenues	Carryover with Interest	Current Year Interest	SBC Requirement	Forecasted Distribution (MWH)	SBC Rate EE Portion (cents/kWh)	SBC Rate EAP Portion (cents/kWh)	SBC Rate LBR Portion (cents/kWh)	Total SBC Rate (cents/kWh)
Col. A	Col. B*	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
2022	$ 44,465	$ 290	$ 1,810	$ 4,777	$ -	$ (2,748)	$ 55	$ 38,168	7,613,036	0.528	0.150	0.185	0.863
2023	$ 47,154	$ 291	$ 1,879	$ 3,994	$ -	$ (2,803)	$ 83	$ 41,572	7,655,948	0.543	0.150	0.205	0.898

Col. A: Effective year (January 1 - December 31)
Col. B: Company Forecast *Excludes Current Year Interest
Col. C: RSA 125-O:5-a Funding level
Col. D: Company Forecast
Col. E: Company Forecast
Col. F: Company Forecast
Col. G: Pages 2, 3 Line 10 Col. B
Col. H: Pages 2, 3, Line 12, Col. O
Col. I: Col. B + Col. C - Col. D - Col. E - Col. F
Col. J: Company Forecast
Col. K: Legislatively set per HB 549
Col. L: EAP Portion of SBC Rate
Col. M: Page 4, Col. G
Col. N: Col. K + Col. L + Col. M

PSNH d/b/a Eversource Energy
Energy Efficiency Expense & SBC Revenue Reconciliation
January 1, 2022 to December 31, 2022
($ in 000's)

Line	Description	Carryover 12/31/2021	Forecast Jan 2022	Forecast Feb 2022	Forecast Mar 2022	Forecast Apr 2022	Forecast May 2022	Forecast June 2022	Forecast Jul 2022	Forecast Aug 2022	Forecast Sep 2022	Forecast Oct 2022	Forecast Nov 2022	Forecast Dec 2022	2022 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	SBC Revenues		2,574	2,309	3,308	2,964	2,999	3,329	3,841	3,754	3,190	3,147	3,146	3,607	38,168
2	RGGI Revenues		-	-	453	-	-	453	-	-	453	-	-	453	1,810
3	FCM Revenues		398	398	398	398	398	398	398	398	398	398	398	398	4,777
4	Other Revenues		-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Total Revenues**		**2,972**	**2,707**	**4,159**	**3,362**	**3,397**	**4,180**	**4,239**	**4,152**	**4,041**	**3,545**	**3,544**	**4,458**	**44,756**
6	RSA 125-O:5-a Funding		24	24	24	24	24	24	24	24	24	24	24	24	290
7	Program Expenses		3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	44,465
8	**Total Program Expenses**		**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**3,730**	**44,756**
9	Current Month (Over)/Under Recovery		758	1,023	(429)	368	333	(450)	(509)	(423)	(311)	184	185	(728)	
10	Cumulative (Over)/Under Recovery	(2,748)	(1,990)	(968)	(1,397)	(1,029)	(696)	(1,146)	(1,656)	(2,078)	(2,389)	(2,205)	(2,020)	(2,748)	
11	Interest @ Prime Rate		0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	
12	**Interest on Deferral Balance**		(6)	(4)	(3)	(3)	(2)	(2)	(4)	(5)	(6)	(6)	(6)	(6)	(55)
13	Monthly Res Sales (MWh)		335,815	279,723	269,456	229,469	214,165	244,836	326,345	307,220	238,881	235,024	253,485	320,855	3,255,273
14	Monthly C&I Sales (MWh)		354,152	339,318	357,136	331,808	353,759	385,630	401,094	403,794	365,301	361,067	342,389	362,316	4,357,763
15	**Total Sales (MWh)**		689,967	619,041	626,592	561,277	567,924	630,466	727,439	711,014	604,181	596,091	595,874	683,171	7,613,036
16	**EE SBC Rate**		0.373	0.373	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	

Line 1: (Line 15 x Line 16) / 100
Line 2: Page 1, Col. D
Line 3: Page 1, Col. E
Line 4: Page 1, Col. F
Line 5: Sum of Line 1 through Line 4
Line 6: RSA 125-O:5-a Funding
Line 7: Page 1, Col. B
Line 8: Line 6 + Line 7
Line 9: (Line 5 - Line 8) * -1
Line 10: Prior month Line 10 + Current month Line 9
Line 11: Prime Rate / 12
Line 12: (Prior Month Line 10 + Current Month Line 10) / 2 x Line 11
Line 13: Company Forecast
Line 14: Company Forecast
Line 15: Line 13 + Line 14
Line 16: Set per HB 549

PSNH d/b/a Eversource Energy
Energy Efficiency Expense & SBC Revenue Reconciliation
January 1, 2023 to December 31, 2023
($ in 000's)

Line	Description	Carryover 12/31/2022	Forecast Jan 2023	Forecast Feb 2023	Forecast Mar 2023	Forecast Apr 2023	Forecast May 2023	Forecast June 2023	Forecast Jul 2023	Forecast Aug 2023	Forecast Sep 2023	Forecast Oct 2023	Forecast Nov 2023	Forecast Dec 2023	2023 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	SBC Revenues		3,734	3,353	3,393	3,119	3,118	3,440	3,970	3,881	3,303	3,261	3,262	3,738	41,572
2	RGGI Revenues		-	-	470	-	-	470	-	-	470	-	-	470	1,879
3	FCM Revenues		333	333	333	333	333	333	333	333	333	333	333	333	3,994
4	Other Revenues		-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Total Revenues**		**4,066**	**3,686**	**4,195**	**3,452**	**3,451**	**4,243**	**4,303**	**4,214**	**4,105**	**3,594**	**3,595**	**4,540**	**47,445**
6	RSA 125-O:5-a Funding		24	24	24	24	24	24	24	24	24	24	24	24	291
7	Program Expenses		3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	47,154
8	**Total Program Expenses**		**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**3,954**	**47,445**
9	Current Month (Over)/Under Recovery		(113)	268	(241)	502	503	(289)	(350)	(260)	(151)	360	359	(587)	
10	Cumulative (Over)/Under Recovery	(2,803)	(2,916)	(2,648)	(2,889)	(2,387)	(1,884)	(2,173)	(2,523)	(2,783)	(2,935)	(2,575)	(2,217)	(2,803)	
11	Interest @ Prime Rate		0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	
12	**Interest on Deferral Balance**		**(8)**	**(8)**	**(7)**	**(7)**	**(6)**	**(5)**	**(6)**	**(7)**	**(8)**	**(7)**	**(6)**	**(7)**	**(83)**
13	Monthly Res Sales (MWh)		336,225	279,663	269,215	233,510	218,026	248,780	330,853	311,872	242,674	239,414	258,026	325,470	3,293,729
14	Monthly C&I Sales (MWh)		351,360	337,822	355,558	340,847	356,203	384,784	400,351	402,933	365,536	361,213	342,747	362,867	4,362,219
15	**Total Sales (MWh)**		687,585	617,484	624,773	574,357	574,228	633,565	731,204	714,805	608,210	600,627	600,773	688,338	7,655,948
16	**EE SBC Rate (inflation applied a 2.774%)**		0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	

Line 1: (Line 15 x Line 16) / 100
Line 2: Page 1, Col. D
Line 3: Page 1, Col. E
Line 4: Page 1, Col. F
Line 5: Sum of Line 1 through Line 4
Line 6: RSA 125-O:5-a Funding
Line 7: Page 1, Col. B
Line 8: Line 6 + Line 7
Line 9: (Line 5 - Line 8) * -1
Line 10: Prior month Line 10 + Current month Line 9
Line 11: Prime Rate / 12
Line 12: (Prior Month Line 10 + Current Month Line 10) / 2 x Line 11
Line 13: Company Forecast
Line 14: Company Forecast
Line 15: Line 13 + Line 14
Line 16: Set per HB 549

PSNH d/b/a Eversource Energy
2022-2023 System Benefits Charge Calculation (LBR Component)
($ in 000's)

Year	Forecasted LBR Revenue	Prior Year Carryover with Interest	Current Year Interest	Total LBR Revenue	Forecasted Distribution (MWH)	SBC Rate LBR Portion (cents/kWh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
2022	$ 10,936	$ 3,054	$ 126	$ 14,116	7,613,036	0.185
2023	$ 12,625	$ 3,017	$ 44	$ 15,686	7,655,948	0.205

Col. A: Effective year (January 1 - December 31)
Col. B: Pages 5, 6, Line 22, Col. O / 1000
Col. C: Pages 7, 8, Line 4, Col. B
Col. D: Pages 7, 8, Line 6, Col. O
Col. E: Col. B + Col. C + Col. D
Col. F: Company Forecast
Col. G: (Col. E * 100) / Col. F

PSNH d/b/a Eversource Energy
Monthly and Cumulative Savings and Lost Base Revenue
January 1, 2022 to December 31, 2022

Line	Description	Cumulative Annual kWh Savings / Monthly kW Savings 12/31/2021	Forecast Jan 2022	Forecast Feb 2022	Forecast Mar 2022	Forecast Apr 2022	Forecast May 2022	Forecast June 2022	Forecast Jul 2022	Forecast Aug 2022	Forecast Sep 2022	Forecast Oct 2022	Forecast Nov 2022	Forecast Dec 2022	2022 Annual kWh and Monthly kW Savings	Cumulative Annual kWh Savings / Monthly kW Savings 12/31/2022
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	
1	Residential Annual kWh Savings (2018-2022)	68,914,757	915,534	915,534	915,534	915,534	915,534	915,534	915,534	915,534	915,534	915,534	915,534	915,534	10,986,406	76,263,089
2	C&I Annual kWh Savings (2018)	38,157,478	-	-	-	-	-	-	-	-	-	-	-	-	-	38,157,478
3	C&I Annual kWh Savings (2019-2022)	215,664,834	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	4,172,829	50,073,946	265,738,780
4	C&I Monthly Installed kW Savings	32,977	614	614	614	614	614	614	614	614	614	614	614	614	7,367	40,344

Line	Description		Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	June 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022 Lost Base Revenue
5	Monthly Residential Savings (2022)		38,147	38,147	38,147	38,147	38,147	38,147	38,147	38,147	38,147	38,147	38,147	38,147	
6	Retired Measures		27,546	27,913	34,891	41,502	40,768	35,259	28,280	26,077	28,648	12,288	-	-	
7	Cumulative Residential Savings	5,742,896	5,753,498	5,801,879	5,843,282	5,878,074	5,913,601	5,954,637	6,002,651	6,052,868	6,100,515	6,164,521	6,240,816	6,317,110	
8	Average Residential kWh Distribution Rate		0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	
9	Total Lost Residential Revenue		$ 289,788	$ 292,225	$ 294,311	$ 296,063	$ 297,852	$ 299,919	$ 302,338	$ 304,867	$ 307,267	$ 310,491	$ 314,333	$ 318,176	$ 3,627,630
10	Monthly C&I Savings (2018)	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	
11	Average C&I kWh Distribution Rate		0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	
12	Lost C&I kWh Revenue		$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	
13	Monthly C&I Savings (2022)		173,868	173,868	173,868	173,868	173,868	173,868	173,868	173,868	173,868	173,868	173,868	173,868	
14	Cumulative C&I Savings	17,972,069	18,145,937	18,493,673	18,841,409	19,189,145	19,536,880	19,884,616	20,232,352	20,580,087	20,927,823	21,275,559	21,623,295	21,971,030	
15	Average C&I kWh Distribution Rate		0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	
16	Lost C&I kWH Revenue		$ 201,063	$ 204,916	$ 208,769	$ 212,622	$ 216,475	$ 220,328	$ 224,181	$ 228,034	$ 231,887	$ 235,740	$ 239,593	$ 243,446	
17	Monthly C&I kW Savings (2022)		307	307	307	307	307	307	307	307	307	307	307	307	
18	Cumulative Monthly C&I kW Savings	32,977	33,284	33,898	34,512	35,126	35,740	36,354	36,968	37,582	38,196	38,810	39,424	40,037	
19	Average C&I Demand Rate		7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	
20	Lost C&I Demand Revenue		$ 259,861	$ 264,655	$ 269,448	$ 274,241	$ 279,034	$ 283,828	$ 288,621	$ 293,414	$ 298,207	$ 303,001	$ 307,794	$ 312,587	
21	Total Lost C&I kWh and Demand Revenue		$ 561,481	$ 570,127	$ 578,773	$ 587,420	$ 596,066	$ 604,712	$ 613,358	$ 622,005	$ 630,651	$ 639,297	$ 647,943	$ 656,590	$ 7,308,422
22	**Total Lost Revenue**		**$ 851,269**	**$ 862,352**	**$ 873,084**	**$ 883,482**	**$ 893,918**	**$ 904,631**	**$ 915,696**	**$ 926,871**	**$ 937,918**	**$ 949,788**	**$ 962,277**	**$ 974,766**	**$ 10,936,052**

*Numbers provided for illustrative purposes only and subject to change.
Lines 1-4: Company Forecast
Line 5: Line 1 / 12 / 2
Line 6: Company Forecast
Line 7: Prior Month Line 7 + Current Month Line 5 + Previous Month Line 5 - Current Month Line 6
Line 8: Page 9, Column 8
Line 9: Line 7 x Line 8
Line 10: Line 2, Column B / 12
Line 11: Page 9, Column 8
Line 12: Line 10 x Line 11
Line 13: Line 3 / 12 / 2
Line 14: Line 3, Column B / 12; Prior Month Line 14 + Current Month Line 13
Line 15: Page 9, Column 7
Line 16: Line 14 x Line 15
Line 17: Line 4 / 2
Line 18: Line 4, Column B; Prior Month Line 18 + Current Month Line 17
Line 19: Page 9, Column 6
Line 20: Line 18 x Line 19
Line 21: Line 12 + Line 16 + Line 20
Line 22: Line 9 + Line 21

PSNH d/b/a Eversource Energy
Monthly and Cumulative Savings and Lost Base Revenue
January 1, 2023 to December 31, 2023

Line	Description	Cumulative Annual kWh Savings / Monthly kW Savings 12/31/2022	Forecast Jan 2023	Forecast Feb 2023	Forecast Mar 2023	Forecast Apr 2023	Forecast May 2023	Forecast June 2023	Forecast Jul 2023	Forecast Aug 2023	Forecast Sep 2023	Forecast Oct 2023	Forecast Nov 2023	Forecast Dec 2023	2023 Annual kWh and Monthly kW Savings	Cumulative Annual kWh Savings / Monthly kW Savings 12/31/2023
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	
1	Residential Annual kWh Savings (2018-2023)	76,263,089	917,742	917,742	917,742	917,742	917,742	917,742	917,742	917,742	917,742	917,742	917,742	917,742	11,012,907	87,275,996
2	C&I Annual kWh Savings (2018)	38,157,478	-	-	-	-	-	-	-	-	-	-	-	-	-	38,157,478
3	C&I Annual kWh Savings (2019-2023)	265,738,780	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	3,871,899	46,462,788	312,201,568
4	C&I Monthly Installed kW Savings	40,344	566	566	566	566	566	566	566	566	566	566	566	566	6,794	47,139

Line	Description		Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	June 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Total 2023 Lost Base Revenue
5	Monthly Residential Savings (2023)		38,239	38,239	38,239	38,239	38,239	38,239	38,239	38,239	38,239	38,239	38,239	38,239	
6	Retired Measures		-	-	-	-	-	-	-	-	-	-	-	-	
7	Cumulative Residential Savings	6,355,257	6,393,497	6,469,975	6,546,454	6,622,932	6,699,411	6,775,889	6,852,368	6,928,846	7,005,325	7,081,803	7,158,282	7,234,760	
8	Average Residential kWh Distribution Rate		0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	0.05037	
9	Total Lost Residential Revenue		$ 322,023	$ 325,875	$ 329,727	$ 333,579	$ 337,432	$ 341,284	$ 345,136	$ 348,988	$ 352,840	$ 356,692	$ 360,544	$ 364,396	$ 4,118,514
10	Monthly C&I Savings (2018)	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	3,179,790	
11	Average C&I kWh Distribution Rate		0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	0.03162	
12	Lost C&I kWh Revenue		$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	$ 100,556	
13	Monthly C&I Savings (2023)		161,329	161,329	161,329	161,329	161,329	161,329	161,329	161,329	161,329	161,329	161,329	161,329	
14	Cumulative C&I Savings	22,144,898	22,306,227	22,628,886	22,951,544	23,274,202	23,596,860	23,919,519	24,242,177	24,564,835	24,887,493	25,210,152	25,532,810	25,855,468	
15	Average C&I kWh Distribution Rate		0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	0.01108	
16	Lost C&I kWH Revenue		$ 247,160	$ 250,735	$ 254,311	$ 257,886	$ 261,461	$ 265,036	$ 268,611	$ 272,186	$ 275,761	$ 279,337	$ 282,912	$ 286,487	
17	Monthly C&I kW Savings (2023)		283	283	283	283	283	283	283	283	283	283	283	283	
18	Cumulative Monthly C&I kW Savings	40,344	40,628	41,194	41,760	42,326	42,892	43,458	44,025	44,591	45,157	45,723	46,289	46,856	
19	Average C&I Demand Rate		7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	
20	Lost C&I Demand Revenue		$ 317,194	$ 321,614	$ 326,035	$ 330,455	$ 334,875	$ 339,296	$ 343,716	$ 348,137	$ 352,557	$ 356,977	$ 361,398	$ 365,818	
21	Total Lost C&I kWh and Demand Revenue		$ 664,911	$ 672,906	$ 680,902	$ 688,897	$ 696,893	$ 704,888	$ 712,884	$ 720,879	$ 728,875	$ 736,870	$ 744,866	$ 752,861	$ 8,506,631
22	**Total Lost Revenue**		**$ 986,934**	**$ 998,782**	**$ 1,010,629**	**$ 1,022,477**	**$ 1,034,324**	**$ 1,046,172**	**$ 1,058,019**	**$ 1,069,867**	**$ 1,081,714**	**$ 1,093,562**	**$ 1,105,409**	**$ 1,117,257**	**$ 12,625,146**

*Numbers provided for illustrative purposes only and subject to change.
Lines 1-4: Company Forecast
Line 5: Line 1 / 12 / 2
Line 6: Company Forecast
Line 7: Prior Month Line 7 + Current Month Line 5 + Previous Month Line 5 - Current Month Line 6
Line 8: Page 9, Column 8
Line 9: Line 7 x Line 8
Line 10: Line 2, Column B / 12
Line 11: Page 9, Column 8
Line 12: Line 10 x Line 11
Line 13: Line 3 / 12 / 2
Line 14: Line 3, Column B / 12; Prior Month Line 14 + Current Month Line 13
Line 15: Page 9, Column 7
Line 16: Line 14 x Line 15
Line 17: Line 4 / 2
Line 18: Line 4, Column B; Prior Month Line 18 + Current Month Line 17
Line 19: Page 9, Column 6
Line 20: Line 18 x Line 19
Line 21: Line 12 + Line 16 + Line 20
Line 22: Line 9 + Line 21

PSNH d/b/a Eversource Energy
Lost Base Revenue Reconciliation (Preliminary)
January 1, 2022 to December 31, 2022
($ in 000's)

Line	Description	Estimated Carryover 12/31/2021	Forecast Jan 2022	Forecast Feb 2022	Forecast Mar 2022	Forecast Apr 2022	Forecast May 2022	Forecast June 2022	Forecast Jul 2022	Forecast Aug 2022	Forecast Sep 2022	Forecast Oct 2022	Forecast Nov 2022	Forecast Dec 2022	2022 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Total Revenue Recovery		448	402	407	365	1,052	1,168	1,347	1,317	1,119	1,104	1,104	1,265	11,100
2	Total Lost Revenues		851	862	873	883	894	905	916	927	938	950	962	975	10,936
3	Current Month (Over)/Under Recovery		403	460	466	519	(158)	(263)	(432)	(390)	(181)	(154)	(141)	(291)	(164)
4	Cumulative (Over)/Under Recovery	3,054	3,457	3,917	4,383	4,901	4,743	4,480	4,048	3,658	3,477	3,323	3,181	2,890	
5	Interest @ Prime Rate		0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	
6	Interest on Deferral Balance		9	10	11	13	13	12	12	10	10	9	9	8	126
7	Cumulative (Over)/Under Recovery Incl Carrying Charge		3,466	3,936	4,413	4,944	4,799	4,548	4,128	3,748	3,577	3,432	3,299	3,017	
8	Total Sales (MWh)		689,967	619,041	626,592	561,277	567,924	630,466	727,439	711,014	604,181	596,091	595,874	683,171	7,613,036
9	**SBC Rate (LBR Component)**		0.065	0.065	0.065	0.065	0.185	0.185	0.185	0.185	0.185	0.185	0.185	0.185	

Line 1: (Line 8 x Line 9) / 100
Line 2: Page 5, Line 22 / 1000
Line 3: Line 2 - Line 1
Line 4: Prior month Line 4 + Current month Line 3
Line 5: Prime Rate / 12
Line 6: (Prior Month Line 4 + Current Month Line 4) / 2 x Line 5
Line 7: Line 4 + Line 6
Line 8: Company Forecast
Line 9: Company Forecast

PSNH d/b/a Eversource Energy
Lost Base Revenue Reconciliation (Preliminary)
January 1, 2023 to December 31, 2023
($ in 000's)

Line	Description	Forecast Carryover 12/31/2022	Forecast Jan 2023	Forecast Feb 2023	Forecast Mar 2023	Forecast Apr 2023	Forecast May 2023	Forecast June 2023	Forecast Jul 2023	Forecast Aug 2023	Forecast Sep 2023	Forecast Oct 2023	Forecast Nov 2023	Forecast Dec 2023	2023 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Total Revenue Recovery		1,411	1,267	1,282	1,178	1,178	1,300	1,500	1,467	1,248	1,232	1,233	1,412	15,707
2	Total Lost Revenues		987	999	1,011	1,022	1,034	1,046	1,058	1,070	1,082	1,094	1,105	1,117	12,625
3	Current Month (Over)/Under Recovery		(424)	(268)	(271)	(156)	(144)	(254)	(442)	(397)	(166)	(139)	(127)	(295)	(3,082)
4	Cumulative (Over)/Under Recovery	3,017	2,593	2,325	2,054	1,898	1,754	1,500	1,058	661	495	357	230	(65)	
5	Interest @ Prime Rate		0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	0.2708%	
6	Interest on Deferral Balance		8	7	6	5	5	4	3	2	2	1	1	0	44
7	Cumulative (Over)/Under Recovery Incl Carrying Charge		2,600	2,339	2,074	1,923	1,784	1,535	1,096	702	538	400	274	(21)	
8	Total Sales (MWh)		687,585	617,484	624,773	574,357	574,228	633,565	731,204	714,805	608,210	600,627	600,773	688,338	7,655,948
9	**SBC Rate (LBR Component)**		0.205	0.205	0.205	0.205	0.205	0.205	0.205	0.205	0.205	0.205	0.205	0.205	

Line 1: (Line 8 x Line 9) / 100
Line 2: Page 6, Line 22 / 1000
Line 3: Line 2 - Line 1
Line 4: Prior month Line 4 + Current month Line 3
Line 5: Prime Rate / 12
Line 6: (Prior Month Line 4 + Current Month Line 4) / 2 x Line 5
Line 7: Line 4 + Line 6
Line 8: Company Forecast
Line 9: Company Forecast

PSNH d/b/a Eversource Energy
Calculation of Forecasted Average Distribution Rate for Lost Revenue
Based on Actual Billing Determinants and Distribution Rates*

For the Period 01/01/21 Through 12/31/21

	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6) = (1) + (4)	(7) = (2) / (5)	(8) = (3) / (5)
	Revenue							
Rate Class	Demand Charges	kWh Charges	Total Demand and kWh Charges	Delivery kW	Delivery kWh	Average Distribution Rate $/kW	Average Distribution Rate $/kWh[a]	Average Distribution Rate $/kWh[b]
Residential	$ -	$ 170,901,070	$ 170,901,070	$ -	3,393,092,962	**N/A**	**N/A**	**$ 0.05037**
General Service Rate G	$ 48,260,328	$ 32,260,699	$ 80,521,027	4,124,831	1,611,507,216	$ 7.82	$ 0.02002	$ 0.04997
Primary General Service Rate GV	$ 25,297,610	$ 10,235,658	$ 35,533,268	3,748,552	1,581,856,864	$ 2.73	$ 0.00647	$ 0.02246
Large General Service Rate LG	$ 15,685,071	$ 5,638,221	$ 21,323,292	3,557,237	1,150,784,833	$ 1.59	$ 0.00490	$ 0.01853
Commercial and Industrial	$ 89,243,010	$ 48,134,577	$ 137,377,587	11,430,620	4,344,148,913	**$ 7.81**	**$ 0.01108**	**$ 0.03162**

* Excludes the outdoor lighting rates (Rate OL and Rate EOL), the Customer/Meter charge revenue from each rate,
and the on/off peak kWh associated with Rate B >= 115 kV under Rate LG.

Bill Impacts of Changes in System Benefits Charge - PSNH d/b/a Eversource Energy

	Current Rates*	2022	2023
Total System Benefits Charge ($/kWh)	$ 0.00743	$ 0.00863	$ 0.00898
Bill per month, including PSNH default energy service			
Residential Rate R (625 kWh/month)	$138.34	$ 139.09	$ 139.31
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)	$2,146.85	$ 2,158.89	$ 2,162.33
Change from previous rate level - $ per month			
Residential Rate R (625 kWh/month)		$ 0.75	$ 0.22
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		$ 12.04	$ 3.45
Change from previous rate level - %			
Residential Rate R (625 kWh/month)		0.5%	0.2%
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		0.6%	0.2%

* Stated at Eversource's rate levels effective February 1st, 2022

Eversource
Calculation of Distribution Revenue at the Rate Levels in Effect January 1 - December 31, 2021
Based on Billing Determinants for the Twelve Months Ending December 2021

Residential Rate R

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Rate	**Source**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Revenue**
Standard	Customer Charge	3,146,221	$ 13.81	$ 43,449,312	2,253,863	$ 13.81	$ 31,125,848	5,400,084	$ 74,575,160
	All kWh	1,916,286,814	$ 0.05116	$ 98,037,233	1,360,469,098	$ 0.05177	$ 70,431,485	3,276,755,912	$ 168,468,719
Uncontrolled Water Heating	Customer Charge	281,031	$ 4.87	$ 1,368,621	198,190	$ 4.87	$ 965,185	479,221	$ 2,333,806
	All kWh	53,144,012	$ 0.02361	$ 1,254,730	31,460,512	$ 0.02393	$ 752,850	84,604,524	$ 2,007,580
Controlled Water Heating	Customer Charge	1,529	$ 6.38	$ 9,755	1,072	$ 4.87	$ 5,221	2,601	$ 14,976
	All kWh	277,615	$ 0.01241	$ 3,445.2	172,550	$ 0.02393	$ 4,129.1	450,165	$ 7,574.3
LCS - Radio-controlled	Customer Charge	22,793	$ 6.99	$ 159,323	16,200	$ 6.99	$ 113,238	38,993	$ 272,561
	All kWh	21,666,856	$ 0.01241	$ 268,886	8,590,074	$ 0.01273	$ 109,352	30,256,930	$ 378,237
LCS - 8 Hour Switch	Customer Charge	68	$ 6.99	$ 475	43	$ 4.87	$ 209	111	$ 685
	All kWh	24,054	$ 0.01241	$ 299	10,838	$ 0.02393	$ 259	34,892	$ 558
LCS - 8 Hour No Switch	Customer Charge	638	$ 6.38	$ 4,070	441	$ 4.87	$ 2,148	1,079	$ 6,218
	All kWh	208,552	$ 0.01241	$ 2,588	101,430	$ 0.02393	$ 2,427	309,982	$ 5,015
LCS - 10,11 Hour Switch	Customer Charge	28	$ 6.99	$ 196	20	$ 4.87	$ 97	48	$ 293
	All kWh	5,277	$ 0.02361	$ 125	2,569	$ 0.02393	$ 61	7,846	$ 186
LCS - 10,11 Hour No Switch	Customer Charge	540	$ 6.38	$ 3,445	379	$ 4.87	$ 1,846	919	$ 5,291
	All kWh	125,980	$ 0.02361	$ 2,974	73,963	$ 0.02393	$ 1,770	199,943	$ 4,744
Time of Day	Customer Charge	286	$ 32.08	$ 9,175	218	$ 32.08	$ 6,993	504	$ 16,168
	On Peak kWh	105,582	$ 0.15015	$ 15,853	71,238	$ 0.15076	$ 10,740	176,820	$ 26,593
	Off Peak kWh	177,890	$ 0.00818	$ 1,455	118,059	$ 0.00818	$ 966	295,949	$ 2,421
Total Residential	Customer/Meter	3,453,134		$ 45,003,897	2,470,426		$ 32,220,576	5,923,560	$ 77,224,474
	Demand	-		-	-		-	-	-
	kWh	1,992,022,632		$ 99,587,290	1,401,070,330		$ 71,313,780	3,393,092,962	$ 170,901,070
				$ 144,591,187			$ 103,534,356		$ 248,125,544

General Service Rate G

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Rate	**Source**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Revenue**
Standard	Single Phase Customer Charge	399,675	$ 16.21	$ 6,478,732	287,406	$ 16.21	$ 4,658,851	687,081	$ 11,137,583
	Three Phase Customer Charge	142,652	$ 32.39	$ 4,620,498	102,310	$ 32.39	$ 3,313,821	244,962	$ 7,934,319
	Demand Charge > 5 kW	2,152,765	$ 11.69	$ 25,165,823	1,959,739	$ 11.69	$ 22,909,343	4,112,504	$ 48,075,166
	First 500 kWh Charge	161,108,587	$ 0.02807	$ 4,522,318	113,875,459	$ 0.02805	$ 3,194,207	274,984,047	$ 7,716,525
	Next 1,000 kWh Charge	166,973,583	$ 0.02268	$ 3,786,961	116,166,992	$ 0.02268	$ 2,634,667	283,140,575	$ 6,421,628
	All Additional kWh Charge	605,130,242	$ 0.01709	$ 10,341,676	436,913,809	$ 0.01709	$ 7,466,857	1,042,044,051	$ 17,808,533
Time of Day	Single Phase Customer Charge	107	$ 41.98	$ 4,492	86	$ 41.98	$ 3,610	193	$ 8,102
	Three Phase Customer Charge	131	$ 60.00	$ 7,860	100	$ 60.00	$ 6,000	231	$ 13,860
	Demand Charge	6,117	$ 14.92	$ 91,266	6,210	$ 15.12	$ 93,897	12,327	$ 185,162
	On peak kWh	146,490	$ 0.05335	$ 7,815	179,702	$ 0.05335	$ 9,587	326,192	$ 17,402
	Off peak kWh	241,814	$ 0.00836	$ 2,022	259,004	$ 0.00836	$ 2,165	500,818	$ 4,187
Space Heating	Meter Charge	2,711	$ 3.24	$ 8,784	1,922	$ 3.24	$ 6,227	4,633	$ 15,011
	All kWh	2,991,842	$ 0.04088	$ 122,307	1,443,493	$ 0.04124	$ 59,530	4,435,335	$ 181,836
Uncontolled Water Heating	Customer Charge	8,250	$ 4.87	$ 40,178	5,831	$ 4.87	$ 28,397	14,081	$ 68,574
	All kWh	1,864,593	$ 0.02361	$ 44,023	1,120,971	$ 0.02393	$ 26,825	2,985,564	$ 70,848
LCS - Radio-controlled	Customer Charge	1,030	$ 6.99	$ 7,200	722	$ 6.99	$ 5,047	1,752	$ 12,246
	All kWh	2,179,234	$ 0.01273	$ 27,746	847,726	$ 0.01273	$ 10,793	3,026,960	$ 38,539
LCS - 8 Hour No Switch	Customer Charge	25	$ 6.38	$ 160	20	$ 4.87	$ 97	45	$ 257
	All kWh	27,745	$ 0.01241	$ 344	9,264	$ 0.02393	$ 222	37,009	$ 566
LCS - 10,11 Hour No Switch	Customer Charge	7	$ 6.38	$ 45	5	$ 4.87	$ 24	12	$ 69
	All kWh	11,425	$ 0.02361	$ 270	15,240	$ 0.02393	$ 365	26,665	$ 634
Total General Service	Customer/Meter	554,588		$ 11,167,947	398,402		$ 8,022,075	952,990	$ 19,190,022
	Demand	2,158,882		$ 25,257,088	1,965,949		$ 23,003,240	4,124,831	$ 48,260,328
	kWh	940,675,556		$ 18,855,481	670,831,660		$ 13,405,218	1,611,507,216	$ 32,260,699
				$ 55,280,517			$ 44,430,533		$ 99,711,049

Primary General Service Rate GV

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Rate	**Source**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Revenue**
Standard	Customer Charge	9,753	$ 211.21	$ 2,059,931	7,157	$ 211.21	$ 1,511,630	16,910	$ 3,571,561
	Minimum Charge	2	$ 1,062.00	$ 2,124	2	$ 1,062.00	$ 2,124	4	$ 4,248
	First 100 kW Demand Charge	902,422	$ 6.90	$ 6,226,712	444,068	$ 6.98	$ 3,099,595	1,346,490	$ 9,326,306
	All Additional kW Demand Charge	1,366,159	$ 6.64	$ 9,071,296	989,744	$ 6.72	$ 6,651,080	2,355,903	$ 15,722,375
	First 200,000 kWh	787,358,490	$ 0.00656	$ 5,165,072	598,393,701	$ 0.00656	$ 3,925,463	1,385,752,191	$ 9,090,534
	All Additional kWh	107,778,506	$ 0.00583	$ 628,349	85,815,205	$ 0.00583	$ 500,303	193,593,711	$ 1,128,651
Rate B	Administrative Charge	70	$ 372.10	$ 26,047	74	$ 372.10	$ 27,535	144	$ 53,582
	Translation Charge	-	$ 62.42	$ -	-	$ 62.42	$ -	-	$ -
	Demand Charge	25,070	$ 5.37	$ 134,626	21,089	$ 5.42	$ 114,302	46,159	$ 248,928
	First 200,000 kWh	1,390,823	$ 0.00656	$ 9,124	1,120,139	$ 0.00656	$ 7,348	2,510,962	$ 16,472
	All Additional kWh	-	$ 0.00583	$ -	-	$ 0.00583	$ -	-	$ -
Total GV	Customer/Meter	9,823		$ 2,085,978	7,231		$ 1,539,165	17,054	$ 3,625,144
	Demand	2,293,651		$ 15,432,633	1,454,901		$ 9,864,977	3,748,552	$ 25,297,610
	kWh	896,527,819		$ 5,802,544	685,329,045		$ 4,433,113	1,581,856,864	$ 10,235,658
				$ 23,321,156			$ 15,837,256		$ 39,158,411

Large General Service Rate LG

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Rate	**Source**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Rate/Charge**	**Revenue**	**Units**	**Rate/Charge**
Standard	Customer Charge	734	$ 660.15	$ 484,550	520	$ 660.15	$ 343,278	1,254	$ 827,828.10
	Demand Charge	1,406,580	$ 5.85	$ 8,228,493	1,078,577	$ 5.92	$ 6,385,176	2,485,157	$ 14,613,668.84
	On peak kWh	267,311,174	$ 0.00554	$ 1,480,904	204,989,709	$ 0.00554	$ 1,135,643	472,300,883	$ 2,616,546.89182
	Off Peak kWh	353,789,849	$ 0.00468	$ 1,655,736	268,402,609	$ 0.00468	$ 1,256,124	622,192,458	$ 2,911,860.70344
Rate B < 115 KV	Administrative Charge	59	$ 372.10	$ 21,954	39	$ 372.10	$ 14,512	98	$ 36,465.80
	Translation Charge	-	$ 62.42	$ -	-	$ 62.42	$ -	-	$ -
	Demand charge	118,183	$ 5.37	$ 634,643	80,583	$ 5.42	$ 436,760	198,766	$ 1,071,402.57
	On peak kWh	5,094,295	$ 0.00554	$ 28,222	3,323,744	$ 0.00554	$ 18,414	8,418,039	$ 46,635.93606
	Off Peak kWh	8,642,373	$ 0.00468	$ 40,446	4,857,098	$ 0.00468	$ 22,731	13,499,471	$ 63,177.52428
Rate B >= 115 KV	Administrative Charge	34	$ 372.10	$ 12,651	26	$ 372.10	$ 9,675	60	$ 22,326.00
	Translation Charge	-	$ 62.42	$ -	-	$ 62.42	$ -	-	$ -
	Demand charge	489,296	$ -	$ -	384,018	$ -	$ -	873,314	$ -
	On peak kWh	4,033,328	$ -	$ -	6,501,964	$ -	$ -	10,535,292	$ -
	Off Peak kWh	9,582,903	$ -	$ -	14,255,787	$ -	$ -	23,838,690	$ -
Total LG	Customer/Meter	827		$ 519,155	585		$ 367,465	1,412	$ 886,620
	Demand	2,014,059		$ 8,863,136	1,543,178		$ 6,821,936	3,557,237	$ 15,685,071
	kWh	648,453,922		$ 3,205,309	502,330,911		$ 2,432,912	1,150,784,833	$ 5,638,221
				$ 12,587,600			$ 9,622,312		$ 22,209,912

Eversource
Calculation of Distribution Revenue at the Rate Levels in Effect January 1 - December 31, 2021
Based on Billing Determinants for the Twelve Months Ending December 2021

Outdoor Lighting Rate OL

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Type	Fixture	Units	Rate/Charge	Revenue	Units	Rate/Charge	Revenue	Units	Rate/Charge
High Pressure Sodium	4,000 Lumens	22,774	$ 15.42	$ 351,178	17,562	$ 15.55	$ 273,082	40,336	$ 624,260.28
	5,800 Lumens	3,893	$ 15.42	$ 60,023	2,995	$ 15.55	$ 46,567	6,887	$ 106,590.11
	9,500 Lumens	6,050	$ 20.51	$ 124,080	4,678	$ 20.68	$ 96,750	10,728	$ 220,829.64
	16,000 Lumens	5,433	$ 29.01	$ 157,609	4,130	$ 29.25	$ 120,816	9,563	$ 278,425.86
	30,000 Lumens	8,511	$ 29.73	$ 253,038	6,570	$ 29.97	$ 196,892	15,081	$ 449,930.33
	50,000 Lumens	12,480	$ 30.06	$ 375,138	9,575	$ 30.31	$ 290,206	22,054	$ 665,343.79
	130,000 Lumens	2,762	$ 48.24	$ 133,215	1,712	$ 48.64	$ 83,285	4,474	$ 216,499.87
	12,000 Lumens	53	$ 21.21	$ 1,124	41	$ 21.39	$ 877	94	$ 2,001.12
	34,200 Lumens	32	$ 21.21	$ 679	26	$ 27.38	$ 712	58	$ 1,390.60
Mercury	3,500 Lumens	29,590	$ 13.60	$ 402,418	22,243	$ 13.71	$ 304,947	51,832	$ 707,365.21
	7,000 Lumens	5,853	$ 16.37	$ 95,808	4,588	$ 16.50	$ 75,709	10,441	$ 171,516.99
	11,000 Lumens	387	$ 20.24	$ 7,836	275	$ 20.40	$ 5,610	662	$ 13,446.26
	15,000 Lumens	18	$ 23.15	$ 417	15	$ 23.34	$ 350	33	$ 766.80
	20,000 Lumens	2,591	$ 24.99	$ 64,741	1,952	$ 25.20	$ 49,195	4,543	$ 113,935.43
	56,000 Lumens	908	$ 39.72	$ 36,063	676	$ 40.05	$ 27,073	1,584	$ 63,135.61
Metal Halide	5,000 Lumens	1,431	$ 16.09	$ 23,031	1,082	$ 16.22	$ 17,551	2,513	$ 40,581.34
	8,000 Lumens	837	$ 22.02	$ 18,433	611	$ 22.20	$ 13,560	1,448	$ 31,992.76
	13,000 Lumens	48	$ 30.21	$ 1,457	35	$ 30.46	$ 1,066	83	$ 2,523.24
	13,500 Lumens	831	$ 30.86	$ 25,660	632	$ 31.11	$ 19,653	1,463	$ 45,313.37
	20,000 Lumens	1,816	$ 30.86	$ 56,043	1,365	$ 31.11	$ 42,462	3,181	$ 98,505.22
	36,000 Lumens	2,843	$ 31.14	$ 88,524	2,165	$ 31.40	$ 67,995	5,008	$ 156,518.51
	100,000 Lumens	1,497	$ 46.68	$ 69,902	1,111	$ 47.07	$ 52,300	2,609	$ 122,201.35
Incandescent	600 Lumens	336	$ 8.89	$ 2,987	240	$ 8.96	$ 2,150	576	$ 5,137.44
	1,000 Lumens	1,222	$ 9.92	$ 12,122	841	$ 10.00	$ 8,405	2,063	$ 20,527.24
	2,500 Lumens	7	$ 12.73	$ 89	5	$ 12.83	$ 64	12	$ 153.26
Fluorescent	20,000 Lumens	12	$ 33.90	$ 407	10	$ 34.18	$ 342	22	$ 748.60
Total Rate OL	Fixtures	112,214		$ 2,362,021	85,134		$ 1,797,619	197,348	
	Demand	-			-			-	
	kWh	9,034,316			16,405,473			16,405,473	
				$ 2,362,021			$ 1,797,619		

Outdoor Lighting Rate EOL

		January 1, 2021 - July 31, 2021			August 1, 2021 - December 31, 2021			January 1, 2021 - December 31, 2021	
Type	Fixture	Units	Rate/Charge	Revenue	Units	Rate/Charge	Revenue	Units	Rate/Charge
High Pressure Sodium	4,000 Lumens	22,936	$ 6.31	$ 144,641	11,529	$ 6.34	$ 73,094	34,465	$ 217,735.03
	5,800 Lumens	799	$ 6.61	$ 5,284	596	$ 6.65	$ 3,963	1,395	$ 9,247.21
	9,500 Lumens	2,163	$ 7.04	$ 15,219	1,441	$ 7.07	$ 10,188	3,604	$ 25,406.97
	16,000 Lumens	3,342	$ 7.69	$ 25,706	2,164	$ 7.73	$ 16,728	5,506	$ 42,433.98
	30,000 Lumens	6,672	$ 8.92	$ 59,506	5,029	$ 8.95	$ 45,010	11,701	$ 104,515.83
	50,000 Lumens	754	$ 10.62	$ 8,009	569	$ 10.66	$ 6,066	1,323	$ 14,074.30
	130,000 Lumens	385	$ 17.30	$ 6,659	275	$ 17.33	$ 4,766	660	$ 11,424.62
Metal Halide	5,000 Lumens	3,867	$ 6.63	$ 25,654	2,530	$ 6.67	$ 16,875	6,397	$ 42,529.48
	8,000 Lumens	129	$ 6.97	$ 899	111	$ 7.01	$ 778	240	$ 1,677.58
	13,000 Lumens	-	$ 7.70	$ -	-	$ 7.74	$ -	-	$ -
	13,500 Lumens	247	$ 7.87	$ 1,944	167	$ 7.91	$ 1,321	414	$ 3,265.28
	20,000 Lumens	248	$ 8.74	$ 2,167	102	$ 8.78	$ 896	350	$ 3,062.83
	36,000 Lumens	(21)	$ 10.45	$ (220)	60	$ 10.49	$ 629	39	$ 409.90
	100,000 Lumens	721	$ 17.12	$ 12,341	515	$ 17.15	$ 8,832	1,236	$ 21,172.86
LED's	Per Fixture	243,369	$ 3.20	$ 778,307	178,029	$ 3.23	$ 575,034	421,398	$ 1,353,340.47
	Per Watt	-	$ 0.0106	$ -	-	$ 0.0106	$ -	-	$ -
	Maintenance credit (contract)	2	($1.90)	$ (4)	7	($1.90)	$ (13)	7	($1.90)
Total Rate EOL	Fixtures	285,611		$ 1,086,114	203,117		$ 764,165	488,728	
	Demand	-		$ -	-		$ -	-	
	kWh	5,174,453		$ -	4,034,324		$ -	9,208,777	
				$ 1,086,114			$ 764,165		

Total Retail

		January 1, 2021 - July 31, 2021		August 1, 2021 - December 31, 2021		January 1, 2021 - December 31, 2021
Type	Source	Units	Revenue	Units	Revenue	Units
Total Retail	Customer/Meter	4,018,372	$ 58,776,978	2,876,644	$ 42,149,281	6,895,016
	Fixtures	397,825	$ 3,448,135	288,251	$ 2,561,784	686,076
	Demand	6,466,592	$ 49,552,858	4,964,028	$ 39,690,152	11,430,620
	kWh	4,491,888,698	$ 127,450,624	3,280,001,743	$ 91,585,023	7,762,856,125
			$ 239,228,595		$ 175,986,241	

Lost Base Revenue
Summary of Data Included in the Calculation of the Average Distribution Rates*

		January 1, 2021 - July 31, 2021		August 1, 2021 - December 31, 2021		January 1, 2021 - December 31, 2021
Type	Source	Units	Revenue	Units	Revenue	Units
Total Residential	Demand	-	$ -	-	$ -	-
	kWh	1,992,022,632	$ 99,587,290	1,401,070,330	$ 71,313,780	3,393,092,962
			$ 99,587,290		$ 71,313,780	
Total General Service	Demand	2,158,882	$ 25,257,088	1,965,949	$ 23,003,240	4,124,831
	kWh	940,675,556	$ 18,855,481	670,831,660	$ 13,405,218	1,611,507,216
			$ 44,112,570		$ 36,408,457	
Total GV	Demand	2,293,651	$ 15,432,633	1,454,901	$ 9,864,977	3,748,552
	kWh	896,527,819	$ 5,802,544	685,329,045	$ 4,433,113	1,581,856,864
			$ 21,235,178		$ 14,298,090	
Total LG	Demand	1,524,763	$ 8,863,136	1,159,160	$ 6,821,936	2,683,923
	kWh	634,837,691	$ 3,205,309	481,573,160	$ 2,432,912	1,116,410,851
			$ 12,068,445		$ 9,254,848	
Total	Demand	5,977,296	$ 49,552,858	4,580,010	$ 39,690,152	10,557,306
	kWh	4,464,063,697	$ 127,450,624	3,238,804,196	$ 91,585,023	7,702,867,893
			$ 177,003,482		$ 131,275,175	

* The Lost Base Revenue calculation excludes the outdoor lighting rates (Rate OL and Rate EOL), the Customer/Meter charge revenue from each rate, and the on/off peak kWh associated with Rate B >= 115 kV under Rate LG.

Program Cost-Effectiveness - 2022 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.57	1.57	1,845.5	1,845.5	1,176.7	-	452.0	4,464.5	67.4	46.0	121	884.9	25,830.2
A1 - Energy Star Homes	6.02	6.31	1,327.5	1,073.7	170.0	50.6	194.1	4,592.3	55.1	4.9	96	791.1	19,681.6
A2 - Home Performance with Energy Star	4.19	4.33	3,299.0	2,675.8	617.4	170.7	56.6	1,175.7	13.3	15.5	84	4,188.4	95,184.3
A3 - Energy Star Products	1.69	1.59	903.9	736.2	461.9	73.3	672.6	6,759.1	153.4	102.0	6,887	(296.5)	2,161.3
A4 - Residential Behavior	1.38	1.11	145.7	116.6	105.4	-	1,152.7	1,152.7	248.8	160.5	10,256	-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	9.1	-	-	-	-	-	-	-	-
A6c - Residential Education	-	-	-	-	46.4	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.61**	**2.49**	**7,521.6**	**6,447.7**	**2,586.9**	**294.6**	**2,527.9**	**18,144.4**	**538.1**	**328.9**	**17,443**	**5,567.9**	**142,857.4**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.50	3.54	4,922.5	4,472.3	1,264.1	2,022.5	4,113.2	57,620.9	308.1	463.6	340	(1,645.9)	(21,273.0)
C2 - Small Business Energy Solutions	1.08	2.13	3,593.9	3,265.9	1,532.4	1,805.7	3,161.4	43,887.4	223.9	315.7	564	(1,057.5)	(13,216.4)
C3 - Municipal Energy Solutions	1.28	2.56	442.2	403.4	157.3	188.3	288.3	3,278.8	43.7	11.1	46	260.7	7,159.2
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	21.2	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	25.0	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.28**	**2.71**	**8,958.6**	**8,141.7**	**3,000.0**	**4,016.5**	**7,562.8**	**104,787.0**	**575.8**	**790.4**	**950**	**(2,442.8)**	**(27,330.2)**
Total	**1.67**	**2.61**	**16,480.2**	**14,589.40**	**5,586.9**	**4,311.1**	**10,090.8**	**122,931.4**	**1,113.8**	**1,119.3**	**18,393**	**3,125.1**	**115,527.2**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual kWh Savings	10,090,780	91.7%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	915,872	8.3%	
	11,006,652	100.0%	

Lifetime kWh Savings	122,931,394	78.4%	**kWh > 65%**
Lifetime MMBTU Savings (in kWh)	33,857,694	21.6%	
	156,789,088	100.0%	

Annual Net Savings as a % of 2019 Sales	1.12%

Spending per Customer	Low-Income	$	957.46
	Residential	$	37.90
	C&I	$	359.80

Present Value Benefits - 2022 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environ-mental
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	Benefits ($000)[3]
Residential Programs																			
B1 - Home Energy Assistance	**$ 1,845**	$ 18	$ -	$ 33	$ 34	$ -	$ 95	$ 95	$ 37	$ 34	$ 23	**$ 370**	$ 675	$ 5	**$ 1,050**	$ 52	$ 743	**$ 795**	**$ 208**
A1 - Energy Star Homes	**$ 1,074**	$ 4	$ -	$ 7	$ 7	$ -	$ 122	$ 153	$ 4	$ 4	$ 14	**$ 314**	$ 702	$ 22	**$ 1,038**	$ 36	$ 254	**$ 290**	**$ 139**
A2 - Home Performance with Energy Star	**$ 2,676**	$ 17	$ -	$ 27	$ 28	$ -	$ 16	$ 18	$ 16	$ 14	$ 3	**$ 138**	$ 2,355	$ 4	**$ 2,497**	$ 179	$ 623	**$ 802**	**$ 39**
A3 - Energy Star Products	**$ 736**	$ 43	$ -	$ 77	$ 79	$ -	$ 145	$ 161	$ 52	$ 42	$ 30	**$ 628**	$ 43	$ 61	**$ 732**	$ 4	$ 168	**$ 171**	**$ 293**
A4 - Residential Behavior	**$ 117**	$ 9	$ -	$ 14	$ 14	$ -	$ 29	$ 24	$ 11	$ 8	$ 7	**$ 117**	$ -	$ -	**$ 117**	$ -	$ 29	**$ 29**	**$ 74**
A6b - Res ISO Forward Capacity Market Expenses	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
A6c - Residential Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Residential	**$ 6,448**	**$ 91**	**$ -**	**$ 157**	**$ 162**	**$ -**	**$ 406**	**$ 451**	**$ 121**	**$ 102**	**$ 77**	**$ 1,566**	**$ 3,774**	**$ 93**	**$ 5,434**	**$ 271**	**$ 1,817**	**$ 2,088**	**$ 753**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 4,472**	$ 333	$ -	$ 560	$ 578	$ -	$ 952	$ 703	$ 889	$ 603	$ 236	**$ 4,853**	$ (351)	$ -	**$ 4,502**	$ (29)	$ 450	**$ 421**	**$ 2,482**
C2 - Small Business Energy Solutions	**$ 3,266**	$ 197	$ -	$ 340	$ 351	$ -	$ 830	$ 530	$ 659	$ 408	$ 184	**$ 3,498**	$ (218)	$ 5	**$ 3,284**	$ (18)	$ 328	**$ 310**	**$ 1,897**
C3 - Municipal Energy Solutions	**$ 403**	$ 6	$ -	$ 11	$ 12	$ -	$ 58	$ 59	$ 35	$ 34	$ 16	**$ 231**	$ 157	$ -	**$ 388**	$ 16	$ 39	**$ 54**	**$ 155**
C6b - C&I ISO Forward Capacity Market Expenses	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
C6c - C&I Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Commercial & Industrial	**$ 8,142**	**$ 536**	**$ -**	**$ 912**	**$ 941**	**$ -**	**$ 1,839**	**$ 1,291**	**$ 1,582**	**$ 1,045**	**$ 436**	**$ 8,582**	**$ (413)**	**$ 5**	**$ 8,174**	**$ (32)**	**$ 817**	**$ 785**	**$ 4,534**
Total	**$ 14,589**	**$ 628**	**$ -**	**$ 1,068**	**$ 1,102**	**$ -**	**$ 2,245**	**$ 1,742**	**$ 1,703**	**$ 1,147**	**$ 512**	**$ 10,148**	**$ 3,362**	**$ 97**	**$ 13,607**	**$ 239**	**$ 2,634**	**$ 2,873**	**$ 5,286**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

	Portfolio Planned Versus Actual Performance - 2022										
	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	122,931,394	*92,198,545*		-	1.925%	-	$ 107,548	*$ 134,435*	$ -	Program Cost Effectiveness (Page 1 of 6)
2	Annual kWh Savings	10,090,780	*7,568,085*		-	0.550%	-	$ 30,728	*$ 38,410*	$ -	Program Cost Effectiveness (Page 1 of 6)
3	Summer Peak Demand kW	1,119	*728*		-	0.660%	-	$ 36,874	*$ 46,092*	$ -	Program Cost Effectiveness (Page 1 of 6)
4	Winter Peak Demand kW	1,114	*724*		-	0.440%	-	$ 24,582	*$ 30,728*	$ -	Program Cost Effectiveness (Page 1 of 6)
5	Total Resource Benefits	$ 13,607,181			-						Present Value Benefits (Page 2 of 6)
6	Total Utility Costs[1]	$ 5,586,900			-						Program Cost Effectiveness (Page 1 of 6)
7	Net Benefits	$ 8,020,281	*$ 6,015,210*	$ -	-	1.925%	-	$ 107,548	*$ 134,435*	$ -	Line 5 minus line 6
8	Total					5.500%	-	$ 307,280	*$ 384,099*	$ -	

		Granite State Test		
		Planned	Actual	Source
9	Total Benefits	$ 14,589,401		Program Cost Effectiveness (Page 1 of 6)
10	Performance Incentive	$ 307,280	$ -	from row 8 above
11	Total Utility Costs	$ 5,586,900	$ -	from row 6 above
12	**Portfolio GST BCR**	**2.48**	-	row 9 divided by rows 10+11

Costs, Benefits, and PI Expressed in 2022 Dollars.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

Program Cost-Effectiveness - 2023 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.59	1.59	1,626.3	1,626.3	1,024.0	-	409.9	4,108.5	58.0	40.2	102	747.0	21,803.8
A1 - Energy Star Homes	6.17	6.78	1,708.2	1,382.5	203.9	73.1	273.5	6,449.0	77.0	7.6	142	930.3	23,116.1
A2 - Home Performance with Energy Star	4.30	4.41	2,945.7	2,390.7	542.3	142.3	48.7	1,011.8	11.5	13.3	72	3,604.6	81,917.9
A3 - Energy Star Products	1.75	1.67	840.0	685.5	410.8	69.2	492.3	5,830.2	111.3	77.9	4,169	39.3	3,026.9
A4 - Residential Behavior	2.17	1.74	236.4	189.2	109.0	-	1,914.0	1,914.0	413.2	266.5	10,256	-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	9.1	-	-	-	-	-	-	-	-
A6c - Residential Education	-	-	-	-	44.6	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.80**	**2.68**	**7,356.7**	**6,274.2**	**2,343.7**	**284.7**	**3,138.3**	**19,313.5**	**671.0**	**405.5**	**14,741**	**5,321.2**	**129,864.7**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.56	3.47	4,385.7	3,984.6	1,148.6	1,653.8	3,523.9	49,812.5	257.7	404.2	299	(1,384.4)	(17,864.7)
C2 - Small Business Energy Solutions	1.10	2.08	3,278.5	2,979.2	1,433.0	1,539.4	2,814.3	39,098.9	199.1	285.4	520	(956.2)	(11,892.0)
C3 - Municipal Energy Solutions	1.32	2.56	457.6	417.5	163.0	182.9	292.8	3,311.3	44.2	11.4	47	258.2	7,135.2
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	21.2	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	24.0	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.32**	**2.65**	**8,121.8**	**7,381.4**	**2,789.8**	**3,376.2**	**6,631.0**	**92,222.7**	**501.0**	**700.9**	**867**	**(2,082.4)**	**(22,621.5)**
Total	**1.76**	**2.66**	**15,478.5**	**13,655.6**	**5,133.5**	**3,660.8**	**9,769.3**	**111,536.2**	**1,172.1**	**1,106.5**	**15,608**	**3,238.8**	**107,243.2**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2023.

Annual kWh Savings	9,769,284	91.1%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	949,189	8.9%	
	10,718,472	100.0%	

Lifetime kWh Savings	111,536,205	78.0%	**kWh > 65%**
Lifetime MMBTU Savings (in kWh)	31,429,883	22.0%	
	142,966,089	100.0%	

Annual Net Savings as a % of 2019 Sales	1.09%

Spending per Customer	Low-Income	$	833.19
	Residential	$	35.47
	C&I	$	334.59

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environ-mental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 1,626**	$ 17	$ -	$ 30	$ 31	$ -	$ 88	$ 89	$ 35	$ 33	$ 22	**$ 344**	$ 590	$ 5	**$ 938**	$ 47	$ 640	**$ 688**	**$ 184**
A1 - Energy Star Homes	**$ 1,382**	$ 7	$ -	$ 11	$ 11	$ -	$ 175	$ 219	$ 7	$ 6	$ 20	**$ 454**	$ 849	$ 34	**$ 1,337**	$ 46	$ 326	**$ 372**	**$ 186**
A2 - Home Performance with Energy Star	**$ 2,391**	$ 15	$ -	$ 24	$ 24	$ -	$ 14	$ 16	$ 14	$ 12	$ 3	**$ 121**	$ 2,099	$ 4	**$ 2,224**	$ 167	$ 555	**$ 722**	**$ 32**
A3 - Energy Star Products	**$ 686**	$ 39	$ -	$ 69	$ 71	$ -	$ 125	$ 141	$ 46	$ 38	$ 26	**$ 555**	$ 63	$ 63	**$ 681**	$ 5	$ 154	**$ 159**	**$ 237**
A4 - Residential Behavior	**$ 189**	$ 9	$ -	$ 23	$ 24	$ -	$ 48	$ 41	$ 18	$ 14	$ 12	**$ 189**	$ -	$ -	**$ 189**	$ -	$ 47	**$ 47**	**$ 133**
A6b - Res ISO Forward Capacity Market Expenses	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
A6c - Residential Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Residential	**$ 6,274**	**$ 86**	**$ -**	**$ 156**	**$ 161**	**$ -**	**$ 450**	**$ 507**	**$ 120**	**$ 103**	**$ 81**	**$ 1,664**	**$ 3,600**	**$ 104**	**$ 5,368**	**$ 265**	**$ 1,723**	**$ 1,988**	**$ 772**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 3,985**	$ 302	$ -	$ 507	$ 524	$ -	$ 822	$ 617	$ 791	$ 548	$ 205	**$ 4,316**	$ (305)	$ -	**$ 4,011**	$ (27)	$ 401	**$ 374**	**$ 2,048**
C2 - Small Business Energy Solutions	**$ 2,979**	$ 181	$ -	$ 313	$ 323	$ -	$ 757	$ 480	$ 601	$ 373	$ 167	**$ 3,195**	$ (203)	$ 5	**$ 2,997**	$ (18)	$ 299	**$ 281**	**$ 1,619**
C3 - Municipal Energy Solutions	**$ 418**	$ 7	$ -	$ 12	$ 12	$ -	$ 59	$ 61	$ 36	$ 35	$ 17	**$ 239**	$ 161	$ -	**$ 401**	$ 17	$ 40	**$ 57**	**$ 151**
C6b - C&I ISO Forward Capacity Market Expenses	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
C6c - C&I Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Commercial & Industrial	**$ 7,381**	**$ 490**	**$ -**	**$ 832**	**$ 859**	**$ -**	**$ 1,639**	**$ 1,158**	**$ 1,428**	**$ 957**	**$ 389**	**$ 7,751**	**$ (346)**	**$ 5**	**$ 7,409**	**$ (28)**	**$ 740**	**$ 713**	**$ 3,819**
Total	**$ 13,656**	**$ 576**	**$ -**	**$ 988**	**$ 1,020**	**$ -**	**$ 2,089**	**$ 1,665**	**$ 1,548**	**$ 1,059**	**$ 470**	**$ 9,415**	**$ 3,254**	**$ 109**	**$ 12,778**	**$ 238**	**$ 2,463**	**$ 2,701**	**$ 4,591**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2023

	Portfolio	**Planned**	**Threshold**	**Actual**	**% of Plan**	**Design Coefficient**	**Actual Coefficient**	**Planned PI**	***125% of Planned PI***	**Actual PI**	**Source**
1	Lifetime kWh Savings	111,536,205	*83,652,154*		-	1.925%	-	$ 98,821	*$ 123,526*	$ -	Program Cost Effectiveness (Page 4 of 6)
2	Annual kWh Savings	9,769,284	*7,326,963*		-	0.550%	-	$ 28,235	*$ 35,293*	$ -	Program Cost Effectiveness (Page 4 of 6)
3	Summer Peak Demand kW	1,106	*719*		-	0.660%	-	$ 33,881	*$ 42,352*	$ -	Program Cost Effectiveness (Page 4 of 6)
4	Winter Peak Demand kW	1,172	*762*		-	0.440%	-	$ 22,588	*$ 28,235*	$ -	Program Cost Effectiveness (Page 4 of 6)
5	Total Resource Benefits	$ 12,777,509			-						Present Value Benefits (Page 5 of 6)
6	Total Utility Costs[1]	$ 5,133,548			-						Program Cost Effectiveness (Page 4 of 6)
7	Net Benefits	$ 7,643,961	*$ 5,732,971*	$ -	-	1.925%	-	$ 98,821	*$ 123,526*	$ -	Line 5 minus line 6
8	Total					5.500%	-	$ 282,345	*$ 352,931*	$ -	

		Granite State Test		
		Planned	**Actual**	**Source**
9	Total Benefits	$ 13,655,570		Program Cost Effectiveness (Page 4 of 6)
10	Performance Incentive	$ 282,345	$ -	from row 8 above
11	Total Utility Costs	$ 5,133,548	$ -	from row 6 above
12	**Portfolio GST BCR**	**2.52**	-	row 9 divided by rows 10+11

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $291,521.36.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Air Sealing, Cord Wood	E21B1a001	-	-									-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Electric	E21B1a002	5	4	2.6	2.2	38.4	32.4	0.8	0.7	-	-	-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Gas	E21B1a003	-	-									-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Kerosene	E21B1a004	1	1	-	-	-	-	-	-	-	-	14.3	12.0	214.0	180.7
B1a - HEA (Weatherization	Air Sealing, Oil	E21B1a005	15	12	-	-	-	-	-	-	-	-	193.0	162.9	2,894.3	2,443.1
B1a - HEA (Weatherization	Air Sealing, Propane	E21B1a006	43	36	0.5	0.4	6.9	5.8	-	-	0.3	0.2	62.1	52.4	931.6	786.4
B1a - HEA (Weatherization	Air Sealing, Wood Pellets	E21B1a007	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Cord Wood	E21B1a084	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Electric	E21B1a085	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Gas	E21B1a086	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Kerosene	E21B1a087	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Oil	E21B1a088	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Propane	E21B1a089	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Wood Pellets	E21B1a090	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Electric	E21B1a009	2	2	0.1	0.1	0.6	0.5	0.0	0.0	0.0	0.0	-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Gas	E21B1a010	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Kerosene	E21B1a011	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Oil	E21B1a012	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Propane	E21B1a013	9	8	-	-	-	-	-	-	-	-	1.3	1.1	9.2	7.8
B1a - HEA (Weatherization	Tank Wrap, Electric	E21B1a091	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Gas	E21B1a092	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Kerosene	E21B1a093	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Oil	E21B1a094	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Propane	E21B1a095	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Electric	E21B1a016	2	2	0.3	0.2	4.1	3.5	0.1	0.0	0.0	0.0	-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Gas	E21B1a017	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Kerosene	E21B1a018	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Oil	E21B1a019	2	2	-	-	-	-	-	-	-	-	1.2	1.0	18.0	15.2
B1a - HEA (Weatherization	Hand Held Showerhead, Propane	E21B1a020	8	7	-	-	-	-	-	-	-	-	4.8	4.1	72.1	60.9
B1a - HEA (Weatherization	Insulation, Cord Wood	E21B1a022	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Electric	E21B1a023	17	14	7.6	6.4	190.6	160.9	2.4	2.0	-	-	76.0	64.2	1,900.8	1,604.5
B1a - HEA (Weatherization	Insulation, Gas	E21B1a024	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Kerosene	E21B1a025	4	4	0.2	0.1	4.4	3.7	-	-	0.1	0.1	21.4	18.1	535.3	451.9
B1a - HEA (Weatherization	Insulation, Oil	E21B1a026	67	57	-	-	-	-	-	-	-	-	482.1	406.9	12,051.8	10,173.1
B1a - HEA (Weatherization	Insulation, Propane	E21B1a027	32	27	1.0	0.8	25.1	21.2	-	-	0.6	0.5	131.4	110.9	3,284.5	2,772.5
B1a - HEA (Weatherization	Insulation, Wood Pellets	E21B1a028	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Cord Wood	E21B1a077	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Electric	E21B1a078	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Gas	E21B1a079	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Kerosene	E21B1a080	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Oil	E21B1a081	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Propane	E21B1a082	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Wood Pellets	E21B1a083	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Electric	E21B1a030	1	1	0.1	0.1	1.8	1.6	0.0	0.0	0.0	0.0	-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Gas	E21B1a031	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Kerosene	E21B1a032	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Oil	E21B1a033	1	1	-	-	-	-	-	-	-	-	0.5	0.5	8.0	6.8
B1a - HEA (Weatherization	Low Flow Showerhead, Propane	E21B1a034	21	18	-	-	-	-	-	-	-	-	12.0	10.1	180.3	152.2
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Electric	E21B1a037	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Gas	E21B1a038	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Kerosene	E21B1a039	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Oil	E21B1a040	1	1	-	-	-	-	-	-	-	-	2.2	1.8	32.3	27.3
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Propane	E21B1a041	1	1	-	-	-	-	-	-	-	-	0.3	0.3	4.7	4.0

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Hot Water Setback, Electric	E21B1a042	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Gas	E21B1a060	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Kerosene	E21B1a061	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Oil	E21B1a062	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Propane	E21B1a063	-	-									-	-	-	-
B1a - HEA (Weatherization	DHW Heat Pump Water Heater	E21B1a043	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Electric	E21B1a096	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Gas	E21B1a097	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Propane	E21B1a099	-	-									-	-	-	-
B1a - HEA (Weatherization	Indirect Water Heater, Oil	E21B1a098	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, General Service Lamps	E21B1a044	35	30	7.3	6.1	14.5	12.3	1.6	1.3	1.0	0.9	(16.5)	(13.9)	(33.0)	(27.9)
B1a - HEA (Weatherization	LED Bulb, Linear	E21B1a045	216	183	144.0	121.5	1,439.7	1,215.3	31.1	26.2	20.0	16.9	(327.1)	(276.1)	(3,271.1)	(2,761.2)
B1a - HEA (Weatherization	LED Bulb, Other Specialty	E21B1a046	1	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.1)
B1a - HEA (Weatherization	LED Bulb, Reflector	E21B1a047	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Fixture	E21B1a048	292	247	85.9	72.5	171.8	145.0	18.5	15.7	12.0	10.1	(195.2)	(164.7)	(390.3)	(329.5)
B1a - HEA (Weatherization	Refrigerator	E21B1a049	250	250	181.7	181.7	2,180.5	2,180.5	7.2	7.2	8.9	8.9	-	-	-	-
B1a - HEA (Weatherization	Freezer	E21B1a050	-	-									-	-	-	-
B1a - HEA (Weatherization	Clothes Washer	E21B1a051	-	-									-	-	-	-
B1a - HEA (Weatherization	Clothes Dryer	E21B1a052	-	-									-	-	-	-
B1a - HEA (Weatherization	Dehumidifier	E21B1a053	-	-									-	-	-	-
B1a - HEA (Weatherization	Room Air Conditioner	E21B1a054	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Cord Wood	E21B1a055	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Electric	E21B1a064	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Gas	E21B1a065	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Kerosene	E21B1a066	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Oil	E21B1a067	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Propane	E21B1a068	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Wood Pellets	E21B1a069	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Cord Wood	E21B1a100	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Electric	E21B1a101	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Gas	E21B1a102	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Kerosene	E21B1a103	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Oil	E21B1a104	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Propane	E21B1a105	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Wood Pellets	E21B1a106	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Cord Wood	E21B1a070	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Electric	E21B1a071	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Gas	E21B1a072	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Kerosene	E21B1a073	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Oil	E21B1a074	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Propane	E21B1a075	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Wood Pellets	E21B1a076	-	-									-	-	-	-
B1a - HEA (Weatherization	Visual Audit	E21B1a056	-	-									-	-	-	-
B1a - HEA (Weatherization	Baseload Audit - SF	E21B1a057	-	-									-	-	-	-
B1a - HEA (Weatherization	Baseload Audit - MF	E21B1a058	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Income Kits	E21B1a059	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Gas	E21B1b001	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Kerosene	E21B1b002	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Boiler Replacement, Oil	E21B1b003	12	10	0.4	0.4	8.1	6.8	0.1	0.1	-	-	191.8	161.9	3,643.3	3,075.4
B1b - HEA (HVAC Systems	Boiler Replacement, Propane	E21B1b004	7	6	13.4	11.3	254.9	215.1	4.0	3.3	-	-	4.1	3.4	77.1	65.1
B1b - HEA (HVAC Systems	Furnace Replacement, Gas	E21B1b005	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Furnace Replacement, Kerosene	E21B1b006	3	3	-	-	-	-	0.1	0.1	-	-	25.9	21.8	439.7	371.2
B1b - HEA (HVAC Systems	Furnace Replacement, Oil	E21B1b007	7	6	-	-	-	-	0.2	0.2	-	-	49.1	41.4	834.0	704.0

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1b - HEA (HVAC Systems	Furnace Replacement, Propane	E21B1b008	7	6	0.6	0.5	10.6	8.9	0.2	0.2	-	-	68.6	57.9	1,166.9	985.0
B1b - HEA (HVAC Systems	Programmable Thermostat, Electric	E21B1b009	3	3	0.7	0.6	10.3	8.7	1.1	0.9	-	-	-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Gas	E21B1b010	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Kerosene	E21B1b011	1	1	-	-	-	-	-	-	-	-	3.0	2.5	44.3	37.4
B1b - HEA (HVAC Systems	Programmable Thermostat, Oil	E21B1b012	23	20	-	-	-	-	-	-	-	-	73.8	62.3	1,107.7	935.1
B1b - HEA (HVAC Systems	Programmable Thermostat, Propane	E21B1b013	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Wood Pellets	E21B1b014	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Electric	E21B1b015	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Gas	E21B1b016	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Kerosene	E21B1b017	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Oil	E21B1b018	1	1	-	-	-	-	-	-	-	-	5.0	4.2	74.7	63.1
B1b - HEA (HVAC Systems	Wifi Thermostat, Propane	E21B1b019	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Wifi Thermostat, Wood Pellets	E21B1b020	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Mini Split HP (cooling)	E21B1b021	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Mini Split HP (heating)	E21B1b022	-	-									-	-	-	-
B1b - HEA (HVAC Systems	ES Central AC	E21B1b023	3	3	5.7	4.8	102.0	86.1	-	-	3.1	2.6	-	-	-	-
B1b - HEA (HVAC Systems	Oil K1 HVAC Repair or Cleaning	E21B1b024	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Gas LP HVAC Repair or Cleaning	E21B1b025	-	-									-	-	-	-
	Home Energy Assistance Subtotal				**452.0**	**409.9**	**4,464.5**	**4,108.5**	**67.4**	**58.0**	**46.0**	**40.2**	**884.9**	**747.0**	**25,830.2**	**21,803.8**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A1a - ES Homes	Cooling, Electric, SF	E21A1a001	-	-									-	-	-	-
A1a - ES Homes	Heating, Electric, SF	E21A1a002	3	4	63.0	73.9	1,573.8	1,846.3	20.0	23.4	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, SF	E21A1a003	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, SF	E21A1a004	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, SF	E21A1a005	27	32	24.7	29.0	618.4	725.5	7.2	8.5	-	-	784.0	919.8	19,600.2	22,995.0
A1a - ES Homes	Heating, Wood Pellets, SF	E21A1a006	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, SF	E21A1a007	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Gas, SF	E21A1a008	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, SF	E21A1a009	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, SF	E21A1a010	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Wood Pellets, SF	E21A1a011	-	-									-	-	-	-
A1a - ES Homes	Cooling, Electric, MF	E21A1a012	1	2	4.2	6.8	104.1	169.5	-	-	2.3	3.7	-	-	-	-
A1a - ES Homes	Heating, Electric, MF	E21A1a013	1	2	38.8	63.2	969.7	1,578.8	12.3	20.0	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, MF	E21A1a014	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, MF	E21A1a015	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, MF	E21A1a016	65	106	44.3	72.2	1,107.9	1,803.9	12.9	21.0	-	-	-	-	-	-
A1a - ES Homes	Heating, Wood Pellets, MF	E21A1a017	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, MF	E21A1a018	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Gas, MF	E21A1a019	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, MF	E21A1a020	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, MF	E21A1a021	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Wood Pellets, MF	E21A1a022	-	-									-	-	-	-
A1a - ES Homes	LED Bulb	E21A1a023	16	23	0.1	0.2	0.3	0.5	0.0	0.0	0.0	0.0	(0.2)	(0.3)	(0.7)	(1.0)
A1a - ES Homes	LED Fixture	E21A1a024	17	25	0.1	0.1	0.3	0.4	0.0	0.0	0.0	0.0	(0.2)	(0.3)	(0.6)	(0.9)
A1a - ES Homes	Refrigerator	E21A1a025	117	173	5.2	7.7	61.8	91.9	0.6	0.9	0.7	1.1	-	-	-	-
A1a - ES Homes	Clothes Washer	E21A1a026	107	160	9.7	14.4	106.3	158.0	1.4	2.0	1.3	1.9	7.5	11.2	82.8	123.0
A1a - ES Homes	Clothes Dryer	E21A1a027	26	39	4.2	6.2	49.9	74.1	0.7	1.1	0.5	0.8	-	-	-	-
A1a - ES Homes	HERS - Lighting and Appliances	E21A1a028	-	-									-	-	-	-
A1a - ES Homes	Residential New Construction Code Compliance	E21A1a029	-	-									-	-	-	-
		ES Homes Subtotal			**194.1**	**273.5**	**4,592.3**	**6,449.0**	**55.1**	**77.0**	**4.9**	**7.6**	**791.1**	**930.3**	**19,681.6**	**23,116.1**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherizat	Air Sealing, Cord Wood	E21A2a001	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Electric	E21A2a002	22	19	5.9	5.1	88.6	76.3	1.9	1.6	-	-	13.6	11.7	203.5	175.2
A2a - HPwES (Weatherizat	Air Sealing, Gas	E21A2a003	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Kerosene	E21A2a004	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Oil	E21A2a005	45	38	0.9	0.8	13.2	11.3	-	-	0.5	0.4	325.1	279.8	4,876.0	4,196.4
A2a - HPwES (Weatherizat	Air Sealing, Propane	E21A2a006	13	11	0.3	0.3	5.0	4.3	-	-	0.2	0.2	86.6	74.6	1,299.5	1,118.4
A2a - HPwES (Weatherizat	Air Sealing, Wood Pellets	E21A2a007	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Cord Wood	E21A2a070	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Electric	E21A2a071	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Gas	E21A2a072	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Kerosene	E21A2a073	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Oil	E21A2a074	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Propane	E21A2a075	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing, Wood Pellets	E21A2a076	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Electric	E21A2a009	9	8	0.3	0.2	2.0	1.7	0.1	0.0	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Gas	E21A2a010	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Kerosene	E21A2a011	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Faucet Aerator, Oil	E21A2a012	1	1	-	-	-	-	-	-	-	-	0.2	0.1	1.1	0.9
A2a - HPwES (Weatherizat	Faucet Aerator, Propane	E21A2a013	3	2	-	-	-	-	-	-	-	-	0.5	0.4	3.2	2.7
A2a - HPwES (Weatherizat	Tank Wrap, Electric	E21A2a077	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Gas	E21A2a078	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Kerosene	E21A2a079	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Oil	E21A2a080	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap, Propane	E21A2a081	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Electric	E21A2a016	3	3	0.5	0.4	7.1	6.1	0.1	0.1	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Gas	E21A2a017	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Kerosene	E21A2a018	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hand Held Showerhead, Oil	E21A2a019	9	7	-	-	-	-	-	-	-	-	6.1	5.3	91.9	79.1
A2a - HPwES (Weatherizat	Hand Held Showerhead, Propane	E21A2a020	3	2	-	-	-	-	-	-	-	-	1.8	1.6	27.6	23.7
A2a - HPwES (Weatherizat	Insulation, Cord Wood	E21A2a022	3	3	2.3	1.9	56.6	48.7	-	-	1.2	1.1	87.5	75.3	2,186.9	1,882.1
A2a - HPwES (Weatherizat	Insulation, Electric	E21A2a023	9	7	12.8	11.0	320.0	275.4	4.1	3.5	-	-	79.4	68.3	1,984.7	1,708.1
A2a - HPwES (Weatherizat	Insulation, Gas	E21A2a024	1	1	-	-	-	-	-	-	-	-	0.3	0.2	7.1	6.1
A2a - HPwES (Weatherizat	Insulation, Kerosene	E21A2a025	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Insulation, Oil	E21A2a026	104	89	19.4	16.7	485.1	417.5	-	-	10.7	9.2	2,576.6	2,217.5	64,415.5	55,437.5
A2a - HPwES (Weatherizat	Insulation, Propane	E21A2a027	23	20	2.7	2.3	67.6	58.2	-	-	1.5	1.3	477.5	410.9	11,936.8	10,273.1
A2a - HPwES (Weatherizat	Insulation, Wood Pellets	E21A2a028	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Cord Wood	E21A2a063	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Electric	E21A2a064	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Gas	E21A2a065	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Kerosene	E21A2a066	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Oil	E21A2a067	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Propane	E21A2a068	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Wood Pellets	E21A2a069	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Electric	E21A2a030	3	2	0.4	0.3	5.3	4.6	0.1	0.1	0.0	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Gas	E21A2a031	1	1	-	-	-	-	-	-	-	-	0.6	0.5	8.4	7.2
A2a - HPwES (Weatherizat	Low Flow Showerhead, Kerosene	E21A2a032	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Oil	E21A2a033	3	2	-	-	-	-	-	-	-	-	1.8	1.6	27.6	23.7
A2a - HPwES (Weatherizat	Low Flow Showerhead, Propane	E21A2a034	1	1	-	-	-	-	-	-	-	-	0.6	0.5	9.2	7.9
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Electric	E21A2a037	7	6	0.7	0.6	10.3	8.8	0.1	0.1	0.1	0.0	-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Gas	E21A2a038	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Kerosene	E21A2a039	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Oil	E21A2a040	9	8	-	-	-	-	-	-	-	-	9.8	8.4	146.4	126.0
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Propane	E21A2a041	9	8	0.1	0.1	1.7	1.5	-	-	-	-	8.8	7.6	131.7	113.4

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherizat	Hot Water Setback, Electric	E21A2a042	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Gas	E21A2a059	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Kerosene	E21A2a060	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Oil	E21A2a061	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback, Propane	E21A2a062	-	-									-	-	-	-
A2a - HPwES (Weatherizat	DHW Heat Pump Water Heater	E21A2a043	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Indirect Water Heater, Oil	E21A2a082	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Indirect Water Heater, Propane	E21A2a083	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, General Service Lamps	E21A2a044	75	65	2.5	2.2	5.1	4.4	0.5	0.5	0.4	0.3	(6.0)	(5.2)	(12.0)	(10.3)
A2a - HPwES (Weatherizat	LED Bulb, Linear	E21A2a045	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Other Specialty	E21A2a046	15	13	0.7	0.6	1.5	1.3	0.2	0.1	0.1	0.1	(1.8)	(1.5)	(3.5)	(3.0)
A2a - HPwES (Weatherizat	LED Bulb, Reflector	E21A2a047	6	5	0.3	0.2	0.6	0.5	0.1	0.1	0.0	0.0	(0.7)	(0.6)	(1.4)	(1.2)
A2a - HPwES (Weatherizat	LED Fixture	E21A2a048	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Refrigerator	E21A2a049	3	3	0.6	0.5	7.4	6.4	0.1	0.1	0.1	0.1	-	-	-	-
A2a - HPwES (Weatherizat	Freezer	E21A2a053	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Clothes Washer	E21A2a054	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Clothes Dryer	E21A2a055	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Dehumidifier	E21A2a056	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Room Air Conditioner	E21A2a057	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Triple Pane Window	E21A2a058	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Cord Wood	E21A2a084	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Electric	E21A2a085	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Gas	E21A2a086	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Kerosene	E21A2a087	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Oil	E21A2a088	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Propane	E21A2a089	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Window Insert, Wood Pellets	E21A2a090	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Visual Audit Oil Savings	E21A2a050	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Visual Audit Propane Savings	E21A2a051	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Visual Audit Electric Savings	E21A2a052	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Gas	E21A2b001	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Kerosene	E21A2b002	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Oil	E21A2b003	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Propane	E21A2b004	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Gas	E21A2b005	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Kerosene	E21A2b006	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Oil	E21A2b007	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Propane	E21A2b008	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Electric	E21A2b009	15	13	3.7	3.2	55.2	47.5	5.9	5.0	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Gas	E21A2b010	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Kerosene	E21A2b011	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Oil	E21A2b012	3	3	-	-	-	-	-	-	-	-	13.5	11.7	203.2	174.9
A2b - HPwES (HVAC Syste	Programmable Thermostat, Propane	E21A2b013	1	1	-	-	-	-	-	-	-	-	3.4	2.9	50.8	43.7
A2b - HPwES (HVAC Syste	Programmable Thermostat, Wood Pellets	E21A2b014	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Electric	E21A2b015	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Gas	E21A2b016	3	3	0.1	0.1	2.2	1.9	-	-	-	-	20.5	17.6	307.2	264.4
A2b - HPwES (HVAC Syste	Wifi Thermostat, Kerosene	E21A2b017	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Oil	E21A2b018	55	47	-	-	-	-	-	-	-	-	365.4	314.5	5,481.2	4,717.2
A2b - HPwES (HVAC Syste	Wifi Thermostat, Propane	E21A2b019	13	11	-	-	-	-	-	-	-	-	84.2	72.5	1,262.9	1,086.9
A2b - HPwES (HVAC Syste	Wifi Thermostat, Wood Pellets	E21A2b020	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	ES Central AC	E21A2b021	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Boiler Circulator Pump	E21A2b022	51	44	0.7	0.6	12.6	10.8	0.2	0.2	-	-	13.9	11.9	257.5	221.6
A2b - HPwES (HVAC Syste	Ancillary Savings – Furnace	E21A2b023	18	15	0.4	0.4	6.6	5.6	0.1	0.1	-	-	19.3	16.6	281.4	242.2

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2b - HPwES (HVAC Syste	Ancillary Savings – Central AC	E21A2b024	39	33	1.2	1.0	22.0	18.9	-	-	0.7	0.6	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Room AC	E21A2b025	1	1	0.0	0.0	0.1	0.1	-	-	0.0	0.0	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Mini-Split AC / HP	E21A2b026	-	-									-	-	-	-
	Home Performance with Energy Star Subtotal				**56.6**	**48.7**	**1,175.7**	**1,011.8**	**13.3**	**11.5**	**15.5**	**13.3**	**4,188.4**	**3,604.6**	**95,184.3**	**81,917.9**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A3a - ES Lighting	LED Bulb, General Service Lamps	E21A3a001	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Linear	E21A3a002	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Other Specialty	E21A3a003	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Reflector	E21A3a004	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, General Service Lamps (Hard to Reach)	E21A3a005	15,000	8,000	170.3	69.7	510.9	209.1	36.8	15.0	23.7	9.7	(386.9)	(158.4)	(1,160.7)	(475.1)
A3a - ES Lighting	LED Bulb, Linear (Hard to Reach)	E21A3a006	300	150	1.2	0.5	12.1	4.6	0.3	0.1	0.2	0.1	(2.7)	(1.1)	(27.4)	(10.5)
A3a - ES Lighting	LED Bulb, Other Specialty (Hard to Reach)	E21A3a007	3,000	1,500	30.8	11.8	92.3	35.4	6.6	2.5	4.3	1.6	(69.9)	(26.8)	(209.7)	(80.5)
A3a - ES Lighting	LED Bulb, Reflector (Hard to Reach)	E21A3a008	4,000	2,000	50.5	19.4	101.0	38.8	10.9	4.2	7.0	2.7	(114.8)	(44.0)	(229.5)	(88.1)
A3a - ES Lighting	LED Fixture	E21A3a009	-	-									-	-	-	-
A3a - ES Lighting	LED Fixture (Hard to Reach)	E21A3a010	-	-									-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier I	E21A3b001	-	-									-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier II	E21A3b002	-	-									-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (cooling)	E21A3b003	12	12	2.5	2.5	45.0	45.0	-	-	1.4	1.4	-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (heating)	E21A3b004	12	12	11.3	11.3	202.7	202.7	5.1	5.1	-	-	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (cooling)	E21A3b005	423	372	48.8	43.0	878.7	773.7	-	-	22.6	19.9	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (heating)	E21A3b006	423	372	161.6	142.3	2,909.1	2,561.7	73.5	64.7	-	-	-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Downstream	E21A3b007	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Downstream	E21A3b008	-	-									-	-	-	-
A3b - ES Appliances	Heat Pump Swimming Pool Heater	E21A3b009	-	-									-	-	-	-
A3b - ES Appliances	ES Clothes Dryers	E21A3b010	148	148	23.7	23.7	284.9	284.9	4.0	4.0	3.1	3.1	-	-	-	-
A3b - ES Appliances	Dryer Heat Pump	E21A3b011	3	3	1.3	1.3	15.2	15.2	0.2	0.2	0.2	0.2	-	-	-	-
A3b - ES Appliances	Dryer Hybrid	E21A3b012	2	2	0.4	0.4	5.1	5.1	0.1	0.1	0.1	0.1	-	-	-	-
A3b - ES Appliances	ECM Motor for FWH Circulating Pump	E21A3b013	-	-									-	-	-	-
A3c - ES HVAC Systems	ES AC (central) 3 ton	E21A3b015	6	6	1.1	1.1	20.0	20.0	-	-	0.6	0.6	-	-	-	-
A3b - ES Appliances	Room Air Conditioner	E21A3b016	39	39	1.3	1.3	11.6	11.6	-	-	0.7	0.7	-	-	-	-
A3b - ES Appliances	ES Clothes Washers	E21A3b017	110	110	9.9	9.9	108.8	108.8	1.4	1.4	1.3	1.3	7.7	7.7	84.7	84.7
A3b - ES Appliances	Washer Tier CEE Tier 2+	E21A3b018	107	107	14.9	14.9	163.5	163.5	2.1	2.1	2.0	2.0	51.4	51.4	565.0	565.0
A3b - ES Appliances	ES Dehumidifier	E21A3b019	113	113	9.3	9.3	111.6	111.6	0.4	0.4	1.8	1.8	-	-	-	-
A3b - ES Appliances	ES Dishwasher	E21A3b020	-	-									-	-	-	-
A3b - ES Appliances	ES Freezers	E21A3b021	-	-									-	-	-	-
A3b - ES Appliances	Refrigerator	E21A3b022	-	-									-	-	-	-
A3b - ES Appliances	Refrigerator CEE Tier 2+	E21A3b023	183	183	17.6	17.6	211.7	211.7	2.0	2.0	2.5	2.5	-	-	-	-
A3b - ES Appliances	ES Pool Pumps (Variable Speed)	E21A3b024	29	29	37.2	37.2	372.4	372.4	-	-	21.5	21.5	-	-	-	-
A3b - ES Appliances	Room Air Purifier	E21A3b025	29	29	11.0	11.0	98.9	98.9	1.3	1.3	1.3	1.3	-	-	-	-
A3c - ES HVAC Systems	Wifi Thermostat (Heating & Cooling)	E21A3b026	30	30	1.4	1.4	20.7	20.7	-	-	-	-	147.6	147.6	2,214.0	2,214.0
A3b - ES Appliances	Primary Refrigerator Recycling	E21A3b027	15	15	15.4	15.4	77.0	77.0	1.8	1.8	2.2	2.2	-	-	-	-
A3b - ES Appliances	Secondary Refrigerator Recycling	E21A3b028	15	15	15.4	15.4	77.0	77.0	1.4	1.4	2.4	2.4	-	-	-	-
A3b - ES Appliances	Secondary Freezer Recycling	E21A3b029	5	5	3.8	3.8	15.4	15.4	0.4	0.4	0.5	0.5	-	-	-	-
A3b - ES Appliances	Room Air Conditioner Recycling	E21A3b030	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit Resistance	E21A3b031	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit HP	E21A3b032	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit HP	E21A3b033	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit Resistance	E21A3b034	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Midstream	E21A3b035	43	38	31.8	28.1	413.6	365.5	5.2	4.6	2.9	2.6	71.2	62.9	925.0	817.4
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Midstream	E21A3b036	-	-									-	-	-	-
	ES Products Subtotal				**672.6**	**492.3**	**6,759.1**	**5,830.2**	**153.4**	**111.3**	**102.0**	**77.9**	**(296.5)**	**39.3**	**2,161.3**	**3,026.9**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1a - LCI Retrofit	Custom Large Compressed Air Retro	E21C1a001	1	1	18.5	18.5	278.1	278.1	5.2	-	5.2	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Hot Water Retro	E21C1a002	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large HVAC Retro	E21C1a003	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Interior	E21C1a004	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Exterior	E21C1a047	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Controls	E21C1a048	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Motors Retro	E21C1a005	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Process Retro	E21C1a006	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Refrigeration Retro	E21C1a007	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Other Retro	E21C1a008	-	-									-	-	-	-
C1a - LCI Retrofit	Daylight Dimming	E21C1a009	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C1a010	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C1a011	20	17	263.5	211.4	3,425.1	2,747.8	5.7	4.6	-	-	-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C1a012	3	3	142.9	134.9	1,858.1	1,753.7	9.1	8.6	11.8	11.2	(98.9)	(93.3)	(1,285.2)	(1,213.0)
C1a - LCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C1a013	170	150	2,003.3	1,669.7	26,139.4	21,786.6	157.1	130.9	203.6	169.7	(1,385.6)	(1,154.9)	(18,080.4)	(15,069.6)
C1a - LCI Retrofit	Lighting Occupancy Sensors	E21C1a014	6	6	33.5	31.6	351.3	331.5	0.0	0.0	0.0	0.0	(91.4)	(86.2)	(959.2)	(905.3)
C1a - LCI Retrofit	Boiler Reset Controls, Electric	E21C1a015	-	-									-	-	-	-
C1a - LCI Retrofit	Case Motor Replacement	E21C1a016	-	-									-	-	-	-
C1a - LCI Retrofit	Cooler Night Cover	E21C1a017	-	-									-	-	-	-
C1a - LCI Retrofit	Demand Control Ventilation	E21C1a018	-	-									-	-	-	-
C1a - LCI Retrofit	Door Heater Controls	E21C1a019	-	-									-	-	-	-
C1a - LCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C1a020	-	-									-	-	-	-
C1a - LCI Retrofit	Duct Sealing, Electric	E21C1a021	-	-									-	-	-	-
C1a - LCI Retrofit	Ductless Mini Split Heat Pump	E21C1a022	-	-									-	-	-	-
C1a - LCI Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C1a023	-	-									-	-	-	-
C1a - LCI Retrofit	Electronic Defrost Control	E21C1a024	-	-									-	-	-	-
C1a - LCI Retrofit	Energy Management System, Electric	E21C1a025	-	-									-	-	-	-
C1a - LCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C1a026	-	-									-	-	-	-
C1a - LCI Retrofit	Evaporator Fan Control	E21C1a027	-	-									-	-	-	-
C1a - LCI Retrofit	Faucet Aerator, Electric	E21C1a028	-	-									-	-	-	-
C1a - LCI Retrofit	Hotel Occupancy Sensor	E21C1a031	-	-									-	-	-	-
C1a - LCI Retrofit	Low Pressure Drop Filter	E21C1a032	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C1a033	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead, Electric	E21C1a034	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Open Drip	E21C1a035	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C1a036	-	-									-	-	-	-
C1a - LCI Retrofit	Novelty Cooler Shutoff	E21C1a037	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Heating, Electric	E21C1a038	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C1a039	-	-									-	-	-	-
C1a - LCI Retrofit	Pre Rinse Spray Valve, Electric	E21C1a040	-	-									-	-	-	-
C1a - LCI Retrofit	Programmable Thermostat, Electric	E21C1a041	-	-									-	-	-	-
C1a - LCI Retrofit	Steam Trap, Electric	E21C1a042	-	-									-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive	E21C1a043	11	11	275.1	275.1	4,025.9	4,025.9	29.1	29.1	26.0	26.0	-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive with Motor	E21C1a044	-	-									-	-	-	-
C1a - LCI Retrofit	Vending Miser	E21C1a045	-	-									-	-	-	-
C1a - LCI Retrofit	Zero Loss Condensate Drain	E21C1a046	-	-									-	-	-	-
C1a - LCI Retrofit	Large Retrocommissioning	E21C1a049	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Compressed Air New	E21C1b001	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Hot Water New	E21C1b002	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large HVAC New	E21C1b003	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Interior	E21C1b004	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Exterior	E21C1b054	1	1	28.1	26.5	140.3	132.5	5.6	5.3	-	-	-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Controls	E21C1b055	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1b - LCI New Equipment	Custom Large Motors New	E21C1b005	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Process New	E21C1b006	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Refrigeration New	E21C1b007	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Other New	E21C1b008	8	7	258.0	225.8	3,483.7	3,048.2	33.0	28.8	31.2	27.3	-	-	-	-
C1b - LCI New Equipment	Custom Large Comprehensive Design	E21C1b056	-	-									-	-	-	-
C1b - LCI New Equipment	Daylight Dimming	E21C1b009	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C1b010	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C1b011	37	33	230.1	193.7	3,414.2	2,874.0	5.1	4.3	-	-	-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Interior w/ Controls	E21C1b012	1	1	2.5	2.4	37.5	35.4	0.2	0.2	0.2	0.2	(0.4)	(0.4)	(6.1)	(5.7)
C1b - LCI New Equipment	Performance Lighting - Interior w/o Controls	E21C1b013	53	40	428.7	305.4	5,799.7	4,131.2	42.4	30.2	55.0	39.2	(69.6)	(49.6)	(942.1)	(671.1)
C1b - LCI New Equipment	Lighting Occupancy Sensors	E21C1b014	-	-									-	-	-	-
C1b - LCI New Equipment	Advanced Power Strip	E21C1b015	-	-									-	-	-	-
C1b - LCI New Equipment	Air Compressor	E21C1b016	1	1	6.4	6.4	95.3	95.3	3.1	3.1	3.7	3.7	-	-	-	-
C1b - LCI New Equipment	Air Nozzle	E21C1b017	-	-									-	-	-	-
C1b - LCI New Equipment	Circulator Pump	E21C1b018	1	1	2.6	2.6	31.0	31.0	0.0	0.0	0.2	0.2	-	-	-	-
C1b - LCI New Equipment	Combination Oven, Electric	E21C1b019	-	-									-	-	-	-
C1b - LCI New Equipment	Compressor Storage	E21C1b020	-	-									-	-	-	-
C1b - LCI New Equipment	Convection Oven, Electric	E21C1b021	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Door Type	E21C1b022	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C1b023	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C1b024	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Single Tank Conveyor	E21C1b025	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Under Counter	E21C1b026	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Door Type	E21C1b027	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C1b028	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Single Tank Conveyor	E21C1b029	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Under Counter	E21C1b030	-	-									-	-	-	-
C1b - LCI New Equipment	Faucet Aerator, Electric	E21C1b031	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Large Vat, Electric	E21C1b032	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Standard Vat, Electric	E21C1b033	-	-									-	-	-	-
C1b - LCI New Equipment	Griddle, Electric	E21C1b034	-	-									-	-	-	-
C1b - LCI New Equipment	Ground Source Heat Pump	E21C1b035	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C1b036	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Full Size	E21C1b037	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Half Size	E21C1b038	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Ice Making Head	E21C1b039	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C1b040	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Continuous	E21C1b041	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Self Contained	E21C1b042	-	-									-	-	-	-
C1b - LCI New Equipment	Low Pressure Drop Filter	E21C1b043	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C1b044	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead, Electric	E21C1b045	-	-									-	-	-	-
C1b - LCI New Equipment	Pre Rinse Spray Valve, Electric	E21C1b046	-	-									-	-	-	-
C1b - LCI New Equipment	Refrigerated Air Dryer	E21C1b047	-	-									-	-	-	-
C1b - LCI New Equipment	Steam Cooker, Electric	E21C1b048	-	-									-	-	-	-
C1b - LCI New Equipment	Unitary Air Conditioner	E21C1b049	25	25	118.8	118.8	1,610.6	1,610.6	-	-	22.6	22.6	-	-	-	-
C1b - LCI New Equipment	Water Source Heat Pump	E21C1b050	-	-									-	-	-	-
C1b - LCI New Equipment	Zero Loss Condensate Drain	E21C1b051	-	-									-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - FL	E21C1b052	1	1	174.0	174.0	4,002.5	4,002.5	4.8	4.8	41.0	41.0	-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - IPLV	E21C1b053	1	1	127.3	127.3	2,928.3	2,928.3	7.7	7.7	63.2	63.2	-	-	-	-
C1b - LCI New Equipment	C&I Large New Construction Code Compliance	E21C1b057	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Circulator Pump	E21C1c001	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Demand Control Ventilation	E21C1c002	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1c - LCI Midstream	Midstream DMSHP Systems	E21C1c003	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C1c004	-	-									-	-	-	-
C1c - LCI Midstream	Midstream ECM Fan Motors	E21C1c005	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Systems	E21C1c006	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Unitary Air Conditioners	E21C1c007	-	-									-	-	-	-
C1c - LCI Midstream	Midstream VRF	E21C1c008	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Water Source Heat Pump Systems	E21C1c009	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Downlight	E21C1c010	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Exterior	E21C1c011	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED High Bay/Low Bay	E21C1c012	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Linear Fixture	E21C1c013	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Linear Fixture with Controls	E21C1c014	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Linear Lamp	E21C1c015	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Screw In	E21C1c016	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Stairwell Kit	E21C1c017	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Combination Oven, Electric	E21C1c018	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Convection Oven, Electric	E21C1c019	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Conveyor Broiler	E21C1c047	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Deck Oven, Electric	E21C1c050	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C1c020	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Multi Tank Convey	E21C1c021	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Pot, Pan, Utensil	E21C1c022	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Single Tank Conve	E21C1c023	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Under Counter	E21C1c024	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C1c025	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Multi Tank Convey	E21C1c026	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Single Tank Conve	E21C1c027	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Under Counter	E21C1c028	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Solid Door	E21C1c029	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Glass Door	E21C1c030	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Large Vat, Electric	E21C1c031	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Standard Vat, Electric	E21C1c032	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Griddle, Electric	E21C1c033	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hand-Wrap Machine	E21C1c051	-	-									-	-	-	-
C1c - LCI Midstream	Midstream High Efficiency Condensing Unit	E21C1c052	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C1c034	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C1c035	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C1c036	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Ice Making Head	E21C1c037	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Batch	E21C1c038	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Contin	E21C1c039	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Self Contained	E21C1c040	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerated Chef Base	E21C1c053	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Glass Door	E21C1c041	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Solid Door	E21C1c042	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Steam Cooker, Electric	E21C1c043	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ultra Low-Temp Freezer	E21C1c048	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 120 gallons	E21C1c044	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 50 gallons	E21C1c045	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 80 gallons	E21C1c046	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Compressed Air Direct Install	E21C1d001	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Hot Water Direct Install	E21C1d002	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large HVAC Direct Install	E21C1d003	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Interior	E21C1d004	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Exterior	E21C1d005	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Controls	E21C1d006	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Motors Direct Install	E21C1d007	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Process Direct Install	E21C1d008	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Refrigeration Direct Install	E21C1d009	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Other Direct Install	E21C1d010	-	-									-	-	-	-
C1d - LCI Direct Install	Daylight Dimming	E21C1d011	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C1d012	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C1d013	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C1d014	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C1d015	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Occupancy Sensors	E21C1d016	-	-									-	-	-	-
C1d - LCI Direct Install	Boiler Reset Controls, Electric	E21C1d017	-	-									-	-	-	-
C1d - LCI Direct Install	Case Motor Replacement	E21C1d018	-	-									-	-	-	-
C1d - LCI Direct Install	Cooler Night Cover	E21C1d019	-	-									-	-	-	-
C1d - LCI Direct Install	Demand Control Ventilation	E21C1d020	-	-									-	-	-	-
C1d - LCI Direct Install	Door Heater Controls	E21C1d021	-	-									-	-	-	-
C1d - LCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C1d022	-	-									-	-	-	-
C1d - LCI Direct Install	Duct Sealing, Electric	E21C1d023	-	-									-	-	-	-
C1d - LCI Direct Install	Ductless Mini Split Heat Pump	E21C1d024	-	-									-	-	-	-
C1d - LCI Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C1d025	-	-									-	-	-	-
C1d - LCI Direct Install	Electronic Defrost Control	E21C1d026	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Management System, Electric	E21C1d027	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C1d028	-	-									-	-	-	-
C1d - LCI Direct Install	Evaporator Fan Control	E21C1d029	-	-									-	-	-	-
C1d - LCI Direct Install	Faucet Aerator, Electric	E21C1d030	-	-									-	-	-	-
C1d - LCI Direct Install	Hotel Occupancy Sensor	E21C1d031	-	-									-	-	-	-
C1d - LCI Direct Install	Low Pressure Drop Filter	E21C1d032	-	-									-	-	-	-
C1d - LCI Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C1d033	-	-									-	-	-	-
C1d - LCI Direct Install	Low-Flow Showerhead, Electric	E21C1d034	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Open Drip	E21C1d035	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C1d036	-	-									-	-	-	-
C1d - LCI Direct Install	Novelty Cooler Shutoff	E21C1d037	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Heating, Electric	E21C1d038	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C1d039	-	-									-	-	-	-
C1d - LCI Direct Install	Pre Rinse Spray Valve, Electric	E21C1d040	-	-									-	-	-	-
C1d - LCI Direct Install	Programmable Thermostat, Electric	E21C1d041	-	-									-	-	-	-
C1d - LCI Direct Install	Steam Trap, Electric	E21C1d042	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive	E21C1d043	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive with Motor	E21C1d044	-	-									-	-	-	-
C1d - LCI Direct Install	Vending Miser	E21C1d045	-	-									-	-	-	-
C1d - LCI Direct Install	Zero Loss Condensate Drain	E21C1d046	-	-									-	-	-	-
	Large Business Energy Solutions Subtotal				**4,113.2**	**3,523.9**	**57,620.9**	**49,812.5**	**308.1**	**257.7**	**463.6**	**404.2**	**(1,645.9)**	**(1,384.4)**	**(21,273.0)**	**(17,864.7)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2a - SCI Retrofit	Custom Small Compressed Air Retro	E21C2a001	1	1	43.4	43.4	564.0	564.0	15.5	15.5	15.5	15.5	-	-	-	-
C2a - SCI Retrofit	Custom Small Hot Water Retro	E21C2a002	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small HVAC Retro	E21C2a003	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Interior	E21C2a004	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Exterior	E21C2a047	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Controls	E21C2a048	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Motors Retro	E21C2a005	1	1	7.9	7.9	118.7	118.7	-	-	-	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Process Retro	E21C2a006	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Refrigeration Retro	E21C2a007	5	5	11.9	11.9	119.1	119.1	3.0	3.0	2.7	2.7	-	-	-	-
C2a - SCI Retrofit	Custom Small Other Retro	E21C2a008	1	1	3.3	3.3	32.6	32.6	0.5	0.5	0.4	0.4	-	-	-	-
C2a - SCI Retrofit	Daylight Dimming	E21C2a009	-	-									-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C2a010	10	10	36.0	34.0	468.2	441.9	1.3	1.3	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C2a011	58	46	257.8	193.0	3,338.7	2,499.2	13.4	10.1	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C2a012	10	10	15.3	14.4	193.8	183.0	4.3	4.1	5.6	5.3	(9.9)	(9.3)	(125.7)	(118.6)
C2a - SCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C2a013	183	175	1,026.2	926.3	13,635.5	12,307.3	100.3	90.5	129.9	117.3	(665.2)	(600.4)	(8,838.7)	(7,977.8)
C2a - SCI Retrofit	Lighting Occupancy Sensors	E21C2a014	8	8	53.3	50.3	479.4	452.4	-	-	-	-	(217.3)	(205.1)	(1,955.8)	(1,846.0)
C2a - SCI Retrofit	Boiler Reset Controls, Electric	E21C2a015	-	-									-	-	-	-
C2a - SCI Retrofit	Case Motor Replacement	E21C2a016	-	-									-	-	-	-
C2a - SCI Retrofit	Cooler Night Cover	E21C2a017	-	-									-	-	-	-
C2a - SCI Retrofit	Demand Control Ventilation	E21C2a018	-	-									-	-	-	-
C2a - SCI Retrofit	Door Heater Controls	E21C2a019	4	4	14.0	14.0	140.4	140.4	1.6	1.6	0.8	0.8	-	-	-	-
C2a - SCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C2a020	-	-									-	-	-	-
C2a - SCI Retrofit	Duct Sealing, Electric	E21C2a021	-	-									-	-	-	-
C2a - SCI Retrofit	Ductless Mini Split Heat Pump	E21C2a022	-	-									-	-	-	-
C2a - SCI Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C2a023	6	6	36.8	36.8	552.7	552.7	4.1	4.1	4.1	4.1	-	-	-	-
C2a - SCI Retrofit	Electronic Defrost Control	E21C2a024	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Management System, Electric	E21C2a025	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C2a026	-	-									-	-	-	-
C2a - SCI Retrofit	Evaporator Fan Control	E21C2a027	9	9	15.4	15.4	153.8	153.8	1.4	1.4	1.4	1.4	-	-	-	-
C2a - SCI Retrofit	Faucet Aerator, Electric	E21C2a028	-	-									-	-	-	-
C2a - SCI Retrofit	Hotel Occupancy Sensor	E21C2a031	-	-									-	-	-	-
C2a - SCI Retrofit	Low Pressure Drop Filter	E21C2a032	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C2a033	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead, Electric	E21C2a034	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Open Drip	E21C2a035	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C2a036	-	-									-	-	-	-
C2a - SCI Retrofit	Novelty Cooler Shutoff	E21C2a037	1	1	1.7	1.7	17.4	17.4	-	-	-	-	-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Heating, Electric	E21C2a038	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C2a039	-	-									-	-	-	-
C2a - SCI Retrofit	Pre Rinse Spray Valve, Electric	E21C2a040	-	-									-	-	-	-
C2a - SCI Retrofit	Programmable Thermostat, Electric	E21C2a041	-	-									-	-	-	-
C2a - SCI Retrofit	Steam Trap, Electric	E21C2a042	-	-									-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive	E21C2a043	2	2	33.5	33.5	502.6	502.6	-	-	-	-	-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive with Motor	E21C2a044	-	-									-	-	-	-
C2a - SCI Retrofit	Vending Miser	E21C2a045	-	-									-	-	-	-
C2a - SCI Retrofit	Zero Loss Condensate Drain	E21C2a046	-	-									-	-	-	-
C2a - SCI Retrofit	Small Retrocommissioning	E21C2a049	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Compressed Air New	E21C2b001	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Hot Water New	E21C2b002	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small HVAC New	E21C2b003	11	11	46.1	46.1	659.9	659.9	7.4	7.4	19.2	19.2	-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Interior	E21C2b004	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Exterior	E21C2b054	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Controls	E21C2b055	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Custom Small Motors New	E21C2b005	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Process New	E21C2b006	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Refrigeration New	E21C2b007	1	1	0.5	0.5	8.2	8.2	0.1	0.1	0.1	0.1	-	-	-	-
C2b - SCI New Equipment	Custom Small Other New	E21C2b008	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Comprehensive Design	E21C2b056	2	2	69.6	69.6	1,392.2	1,392.2	-	-	-	-	-	-	-	-
C2b - SCI New Equipment	Daylight Dimming	E21C2b009	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C2b010	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C2b011	17	17	72.2	68.2	1,083.1	1,022.3	0.0	0.0	-	-	-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/ Controls	E21C2b012	2	2	1.8	1.7	27.7	26.1	0.1	0.1	0.1	0.1	(0.3)	(0.3)	(4.2)	(4.0)
C2b - SCI New Equipment	Performance Lighting - Interior w/o Controls	E21C2b013	176	155	845.7	702.9	12,685.1	10,543.9	67.0	55.7	86.8	72.2	(128.7)	(107.0)	(1,931.1)	(1,605.1)
C2b - SCI New Equipment	Lighting Occupancy Sensors	E21C2b014	2	2	8.8	8.3	88.4	83.5	-	-	-	-	(36.1)	(34.1)	(360.8)	(340.6)
C2b - SCI New Equipment	Advanced Power Strip	E21C2b015	-	-									-	-	-	-
C2b - SCI New Equipment	Air Compressor	E21C2b016	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Air Nozzle	E21C2b017	-	-									-	-	-	-
C2b - SCI New Equipment	Circulator Pump	E21C2b018	5	5	17.2	17.2	274.6	274.6	0.4	0.4	5.9	5.9	-	-	-	-
C2b - SCI New Equipment	Combination Oven, Electric	E21C2b019	-	-									-	-	-	-
C2b - SCI New Equipment	Compressor Storage	E21C2b020	-	-									-	-	-	-
C2b - SCI New Equipment	Convection Oven, Electric	E21C2b021	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Door Type	E21C2b022	1	1	4.2	4.2	62.3	62.3	0.7	0.7	0.7	0.7	-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C2b023	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C2b024	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Single Tank Conveyor	E21C2b025	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Under Counter	E21C2b026	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Door Type	E21C2b027	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C2b028	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Single Tank Conveyor	E21C2b029	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Under Counter	E21C2b030	-	-									-	-	-	-
C2b - SCI New Equipment	Faucet Aerator, Electric	E21C2b031	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Large Vat, Electric	E21C2b032	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Standard Vat, Electric	E21C2b033	-	-									-	-	-	-
C2b - SCI New Equipment	Griddle, Electric	E21C2b034	-	-									-	-	-	-
C2b - SCI New Equipment	Ground Source Heat Pump	E21C2b035	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C2b036	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Full Size	E21C2b037	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Half Size	E21C2b038	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Ice Making Head	E21C2b039	1	1	1.1	1.1	8.9	8.9	0.3	0.3	0.3	0.3	-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C2b040	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Continuous	E21C2b041	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Self Contained	E21C2b042	-	-									-	-	-	-
C2b - SCI New Equipment	Low Pressure Drop Filter	E21C2b043	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C2b044	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead, Electric	E21C2b045	-	-									-	-	-	-
C2b - SCI New Equipment	Pre Rinse Spray Valve, Electric	E21C2b046	-	-									-	-	-	-
C2b - SCI New Equipment	Refrigerated Air Dryer	E21C2b047	-	-									-	-	-	-
C2b - SCI New Equipment	Steam Cooker, Electric	E21C2b048	1	1	30.2	30.2	361.9	361.9	-	-	-	-	-	-	-	-
C2b - SCI New Equipment	Unitary Air Conditioner	E21C2b049	22	20	74.9	68.1	898.3	816.7	-	-	13.9	12.6	-	-	-	-
C2b - SCI New Equipment	Water Source Heat Pump	E21C2b050	-	-									-	-	-	-
C2b - SCI New Equipment	Zero Loss Condensate Drain	E21C2b051	-	-									-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - FL	E21C2b052	2	2	77.3	77.3	1,778.9	1,778.9	-	-	-	-	-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - IPLV	E21C2b053	-	-									-	-	-	-
C2b - SCI New Equipment	C&I Small New Construction Code Compliance	E21C2b057	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Circulator Pump	E21C2c001	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Demand Control Ventilation	E21C2c002	-	-									-	-	-	-
C2c - SCI Midstream	Midstream DMSHP Systems	E21C2c003	1	1	0.8	0.8	10.0	10.0	-	-	0.0	0.0	-	-	-	-
C2c - SCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C2c004	1	1	10.1	10.1	101.5	101.5	-	-	3.5	3.5	-	-	-	-
C2c - SCI Midstream	Midstream ECM Fan Motors	E21C2c005	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Systems	E21C2c006	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Unitary Air Conditioners	E21C2c007	-	-									-	-	-	-
C2c - SCI Midstream	Midstream VRF	E21C2c008	13	12	341.2	319.0	4,094.3	3,827.9	-	-	22.2	20.8	-	-	-	-
C2c - SCI Midstream	Midstream Water Source Heat Pump Systems	E21C2c009	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Downlight	E21C2c010	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Exterior	E21C2c011	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED High Bay/Low Bay	E21C2c012	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Linear Fixture	E21C2c013	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Linear Fixture with Controls	E21C2c014	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Linear Lamp	E21C2c015	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream LED Screw In	E21C2c016	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Stairwell Kit	E21C2c017	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Combination Oven, Electric	E21C2c018	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Convection Oven, Electric	E21C2c019	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Conveyor Broiler	E21C2c047	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Deck Oven, Electric	E21C2c050	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C2c020	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Multi Tank Convey	E21C2c021	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Pot, Pan, Utensil	E21C2c022	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Single Tank Conve	E21C2c023	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Under Counter	E21C2c024	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C2c025	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Multi Tank Convey	E21C2c026	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Single Tank Conve	E21C2c027	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Under Counter	E21C2c028	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Solid Door	E21C2c029	3	3	1.8	1.8	22.1	22.1	-	-	-	-	-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Glass Door	E21C2c030	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Fryer Large Vat, Electric	E21C2c031	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Fryer Standard Vat, Electric	E21C2c032	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Griddle, Electric	E21C2c033	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hand-Wrap Machine	E21C2c051	-	-									-	-	-	-
C2c - SCI Midstream	Midstream High Efficiency Condensing Unit	E21C2c052	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C2c034	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C2c035	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C2c036	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Ice Making Head	E21C2c037	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Batch	E21C2c038	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Unit Contin	E21C2c039	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Self Contained	E21C2c040	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerated Chef Base	E21C2c053	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Glass Door	E21C2c041	2	2	0.7	0.7	8.7	8.7	-	-	-	-	-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Solid Door	E21C2c042	2	2	0.4	0.4	4.4	4.4	2.7	2.7	2.7	2.7	-	-	-	-
C2c - SCI Midstream	Midstream Steam Cooker, Electric	E21C2c043	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ultra Low-Temp Freezer	E21C2c048	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 120 gallons	E21C2c044	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 50 gallons	E21C2c045	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 80 gallons	E21C2c046	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Compressed Air Direct Install	E21C2d001	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Hot Water Direct Install	E21C2d002	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small HVAC Direct Install	E21C2d003	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Interior	E21C2d004	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Exterior	E21C2d005	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Controls	E21C2d006	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Motors Direct Install	E21C2d007	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Process Direct Install	E21C2d008	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Refrigeration Direct Install	E21C2d009	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Other Direct Install	E21C2d010	-	-									-	-	-	-
C2d - SCI Direct Install	Daylight Dimming	E21C2d011	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C2d012	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C2d013	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C2d014	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C2d015	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Occupancy Sensors	E21C2d016	-	-									-	-	-	-
C2d - SCI Direct Install	Boiler Reset Controls, Electric	E21C2d017	-	-									-	-	-	-
C2d - SCI Direct Install	Case Motor Replacement	E21C2d018	-	-									-	-	-	-
C2d - SCI Direct Install	Cooler Night Cover	E21C2d019	-	-									-	-	-	-
C2d - SCI Direct Install	Demand Control Ventilation	E21C2d020	-	-									-	-	-	-
C2d - SCI Direct Install	Door Heater Controls	E21C2d021	-	-									-	-	-	-
C2d - SCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C2d022	-	-									-	-	-	-
C2d - SCI Direct Install	Duct Sealing, Electric	E21C2d023	-	-									-	-	-	-
C2d - SCI Direct Install	Ductless Mini Split Heat Pump	E21C2d024	-	-									-	-	-	-
C2d - SCI Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C2d025	-	-									-	-	-	-
C2d - SCI Direct Install	Electronic Defrost Control	E21C2d026	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Management System, Electric	E21C2d027	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C2d028	-	-									-	-	-	-
C2d - SCI Direct Install	Evaporator Fan Control	E21C2d029	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2d - SCI Direct Install	Faucet Aerator, Electric	E21C2d030	-	-									-	-	-	-
C2d - SCI Direct Install	Hotel Occupancy Sensor	E21C2d031	-	-									-	-	-	-
C2d - SCI Direct Install	Low Pressure Drop Filter	E21C2d032	-	-									-	-	-	-
C2d - SCI Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C2d033	-	-									-	-	-	-
C2d - SCI Direct Install	Low-Flow Showerhead, Electric	E21C2d034	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Open Drip	E21C2d035	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C2d036	-	-									-	-	-	-
C2d - SCI Direct Install	Novelty Cooler Shutoff	E21C2d037	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Heating, Electric	E21C2d038	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C2d039	-	-									-	-	-	-
C2d - SCI Direct Install	Pre Rinse Spray Valve, Electric	E21C2d040	-	-									-	-	-	-
C2d - SCI Direct Install	Programmable Thermostat, Electric	E21C2d041	-	-									-	-	-	-
C2d - SCI Direct Install	Steam Trap, Electric	E21C2d042	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive	E21C2d043	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive with Motor	E21C2d044	-	-									-	-	-	-
C2d - SCI Direct Install	Vending Miser	E21C2d045	-	-									-	-	-	-
C2d - SCI Direct Install	Zero Loss Condensate Drain	E21C2d046	-	-									-	-	-	-
	Small Business Energy Solutions Subtotal				**3,161.4**	**2,814.3**	**43,887.4**	**39,098.9**	**223.9**	**199.1**	**315.7**	**285.4**	**(1,057.5)**	**(956.2)**	**(13,216.4)**	**(11,892.0)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Custom Muni Compressed Air Retro	E21C3a001	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Hot Water Retro	E21C3a002	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni HVAC Retro	E21C3a003	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Interior	E21C3a004	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Exterior	E21C3a091	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Controls	E21C3a092	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Motors Retro	E21C3a005	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Process Retro	E21C3a006	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Refrigeration Retro	E21C3a007	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Other Retro	E21C3a008	-	-									-	-	-	-
C3a - Muni Retrofit	Daylight Dimming	E21C3a009	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/ Controls	E21C3a010	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/o Controls	E21C3a011	12	13	139.8	143.0	1,398.4	1,429.7	27.2	27.8	-	-	-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Interior w/ Controls	E21C3a012	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Interior w/o Controls	E21C3a013	7	8	71.5	75.4	714.8	754.4	5.2	5.5	6.8	7.1	(46.3)	(48.9)	(463.4)	(489.0)
C3a - Muni Retrofit	Lighting Occupancy Sensors	E21C3a014	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Electric	E21C3a015	2	2	10.0	10.0	150.6	150.6	3.2	3.2	-	-	-	-	-	-
C3a - Muni Retrofit	Air Sealing, Gas	E21C3a016	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Oil	E21C3a017	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Propane	E21C3a018	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Gas	E21C3a019	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Oil	E21C3a020	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Propane	E21C3a021	-	-									-	-	-	-
C3a - Muni Retrofit	Case Motor Replacement	E21C3a022	-	-									-	-	-	-
C3a - Muni Retrofit	Cooler Night Cover	E21C3a023	-	-									-	-	-	-
C3a - Muni Retrofit	Demand Control Ventilation	E21C3a024	-	-									-	-	-	-
C3a - Muni Retrofit	Door Heater Controls	E21C3a025	-	-									-	-	-	-
C3a - Muni Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C3a026	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Electric	E21C3a027	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Gas	E21C3a028	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Oil	E21C3a029	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Propane	E21C3a030	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Electric	E21C3a031	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Gas	E21C3a032	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Oil	E21C3a033	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Propane	E21C3a034	-	-									-	-	-	-
C3a - Muni Retrofit	Ductless Mini Split Heat Pump	E21C3a035	-	-									-	-	-	-
C3a - Muni Retrofit	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C3a036	-	-									-	-	-	-
C3a - Muni Retrofit	Electronic Defrost Control	E21C3a037	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Management System, Electric	E21C3a038	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Electric	E21C3a039	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Gas	E21C3a040	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Oil	E21C3a041	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Propane	E21C3a042	-	-									-	-	-	-
C3a - Muni Retrofit	Evaporator Fan Control	E21C3a043	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Electric	E21C3a044	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Gas	E21C3a045	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Oil	E21C3a046	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Propane	E21C3a047	-	-									-	-	-	-
C3a - Muni Retrofit	Hotel Occupancy Sensor	E21C3a050	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Electric	E21C3a051	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Gas	E21C3a052	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Oil	E21C3a053	1	1	1.9	1.9	47.1	47.1	-	-	1.0	1.0	284.0	284.0	7,099.3	7,099.3

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Insulation, Propane	E21C3a054	-	-									-	-	-	-
C3a - Muni Retrofit	Low Pressure Drop Filter	E21C3a055	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C3a056	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3a057	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3a058	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3a059	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Electric	E21C3a060	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Gas	E21C3a061	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Oil	E21C3a062	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Propane	E21C3a063	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Open Drip	E21C3a064	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Totally Enclosed Fan Cooled	E21C3a065	-	-									-	-	-	-
C3a - Muni Retrofit	Novelty Cooler Shutoff	E21C3a066	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Electric	E21C3a067	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Gas	E21C3a068	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Oil	E21C3a069	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Propane	E21C3a070	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Electric	E21C3a071	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Gas	E21C3a072	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Oil	E21C3a073	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Propane	E21C3a074	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Electric	E21C3a075	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Gas	E21C3a076	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Oil	E21C3a077	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Propane	E21C3a078	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Electric	E21C3a079	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Gas	E21C3a080	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Oil	E21C3a081	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Propane	E21C3a082	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Electric	E21C3a083	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Gas	E21C3a084	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Oil	E21C3a085	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Propane	E21C3a086	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive	E21C3a087	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive with Motor	E21C3a088	-	-									-	-	-	-
C3a - Muni Retrofit	Vending Miser	E21C3a089	-	-									-	-	-	-
C3a - Muni Retrofit	Zero Loss Condensate Drain	E21C3a090	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Compressed Air New	E21C3b001	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Hot Water New	E21C3b002	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni HVAC New	E21C3b003	5	5	11.6	11.6	174.1	174.1	0.8	0.8	2.0	2.0	-	-	-	-
C3b - Muni New Equipmen	Custom Muni Lighting New - Interior	E21C3b004	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Lighting New - Exterior	E21C3b085	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Lighting New - Controls	E21C3b086	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Motors New	E21C3b005	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Process New	E21C3b006	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Refrigeration New	E21C3b007	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Other New	E21C3b008	3	3	7.9	7.9	110.0	110.0	-	-	-	-	-	-	-	-
C3b - Muni New Equipmen	Custom Muni Comprehensive Design	E21C3b087	-	-									-	-	-	-
C3b - Muni New Equipmen	Daylight Dimming	E21C3b009	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Exterior w/ Controls	E21C3b010	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Exterior w/o Controls	E21C3b011	5	5	32.6	30.8	489.3	461.8	6.4	6.0	-	-	-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Interior w/ Controls	E21C3b012	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Interior w/o Controls	E21C3b013	9	9	13.0	12.2	194.4	183.5	0.9	0.9	1.2	1.2	(2.0)	(1.9)	(29.6)	(27.9)

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipmen	Lighting Occupancy Sensors	E21C3b014	-	-									-	-	-	-
C3b - Muni New Equipmen	Advanced Power Strip	E21C3b015	-	-									-	-	-	-
C3b - Muni New Equipmen	Air Compressor	E21C3b016	-	-									-	-	-	-
C3b - Muni New Equipmen	Air Nozzle	E21C3b017	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1000 to 1700 MBH 90 AFUE, Oil	E21C3b018	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1000 to 1700 MBH 90 AFUE, Propane	E21C3b019	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1701 to 2000 MBH 85 AFUE, Oil	E21C3b020	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1701 to 2000 MBH 90 AFUE, Propane	E21C3b021	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 301 to 499 MBH 85 AFUE, Oil	E21C3b022	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 301 to 499 MBH 90 AFUE, Propane	E21C3b023	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 500 to 999 MBH 85 AFUE, Oil	E21C3b024	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 500 to 999 MBH 90 AFUE, Propane	E21C3b025	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 85 AFUE, Oil	E21C3b026	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 87 AFUE, Oil	E21C3b027	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 90 AFUE, Propane	E21C3b028	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 95 AFUE, Propane	E21C3b029	1	1	-	-	-	-	-	-	-	-	14.7	14.7	367.5	367.5
C3b - Muni New Equipmen	Circulator Pump	E21C3b030	-	-									-	-	-	-
C3b - Muni New Equipmen	Combination Oven, Electric	E21C3b031	-	-									-	-	-	-
C3b - Muni New Equipmen	Compressor Storage	E21C3b032	-	-									-	-	-	-
C3b - Muni New Equipmen	Condensing Unit Heater up to 300 MBH, Oil	E21C3b033	-	-									-	-	-	-
C3b - Muni New Equipmen	Condensing Unit Heater up to 300 MBH, Propane	E21C3b034	-	-									-	-	-	-
C3b - Muni New Equipmen	Convection Oven, Electric	E21C3b035	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Door Type	E21C3b036	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Multi Tank Conveyor	E21C3b037	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Pot, Pan, Utensil	E21C3b038	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Single Tank Conveyor	E21C3b039	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Under Counter	E21C3b040	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Door Type	E21C3b041	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Multi Tank Conveyor	E21C3b042	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Single Tank Conveyor	E21C3b043	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Under Counter	E21C3b044	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Electric	E21C3b045	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Gas	E21C3b046	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Oil	E21C3b047	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Propane	E21C3b048	-	-									-	-	-	-
C3b - Muni New Equipmen	Fryer Large Vat, Electric	E21C3b049	-	-									-	-	-	-
C3b - Muni New Equipmen	Fryer Standard Vat, Electric	E21C3b050	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 85 AFUE up to 150 MBH, Oil	E21C3b051	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 87 AFUE up to 150 MBH, Oil	E21C3b052	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 95 AFUE up to 150 MBH, Propane	E21C3b053	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 97 AFUE up to 150 MBH, Propane	E21C3b054	1	1	-	-	-	-	-	-	-	-	10.3	10.3	185.4	185.4
C3b - Muni New Equipmen	Griddle, Electric	E21C3b055	-	-									-	-	-	-
C3b - Muni New Equipmen	Ground Source Heat Pump	E21C3b056	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet 3/4 Size	E21C3b057	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet Full Size	E21C3b058	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet Half Size	E21C3b059	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Ice Making Head	E21C3b060	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Remote Cond./Split Unit - Batch	E21C3b061	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Remote Cond./Split Unit - Continuous	E21C3b062	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Self Contained	E21C3b063	-	-									-	-	-	-
C3b - Muni New Equipmen	Infrared Heater	E21C3b064	-	-									-	-	-	-
C3b - Muni New Equipmen	Low Pressure Drop Filter	E21C3b065	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C3b066	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3b067	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3b068	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3b069	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Electric	E21C3b070	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Gas	E21C3b071	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Oil	E21C3b072	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Propane	E21C3b073	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Electric	E21C3b074	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Gas	E21C3b075	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Oil	E21C3b076	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Propane	E21C3b077	-	-									-	-	-	-
C3b - Muni New Equipmen	Refrigerated Air Dryer	E21C3b078	-	-									-	-	-	-
C3b - Muni New Equipmen	Steam Cooker, Electric	E21C3b079	-	-									-	-	-	-
C3b - Muni New Equipmen	Unitary Air Conditioner	E21C3b080	-	-									-	-	-	-
C3b - Muni New Equipmen	Water Source Heat Pump	E21C3b081	-	-									-	-	-	-
C3b - Muni New Equipmen	Zero Loss Condensate Drain	E21C3b082	-	-									-	-	-	-
C3b - Muni New Equipmen	High Efficiency Chiller - FL	E21C3b083	-	-									-	-	-	-
C3b - Muni New Equipmen	High Efficiency Chiller - IPLV	E21C3b084	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Compressed Air Direct Install	E21C3d001	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Hot Water Direct Install	E21C3d002	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni HVAC Direct Install	E21C3d003	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Interior	E21C3d004	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Exterior	E21C3d005	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Controls	E21C3d006	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Motors Direct Install	E21C3d007	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Process Direct Install	E21C3d008	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Refrigeration Direct Install	E21C3d009	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Other Direct Install	E21C3d010	-	-									-	-	-	-
C3d - Muni Direct Install	Daylight Dimming	E21C3d011	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/ Controls	E21C3d012	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/o Controls	E21C3d013	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Interior w/ Controls	E21C3d014	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Interior w/o Controls	E21C3d015	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Occupancy Sensors	E21C3d016	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Electric	E21C3d017	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Gas	E21C3d018	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Oil	E21C3d019	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Propane	E21C3d020	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Gas	E21C3d021	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Boiler Reset Controls, Oil	E21C3d022	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Propane	E21C3d023	-	-									-	-	-	-
C3d - Muni Direct Install	Case Motor Replacement	E21C3d024	-	-									-	-	-	-
C3d - Muni Direct Install	Cooler Night Cover	E21C3d025	-	-									-	-	-	-
C3d - Muni Direct Install	Demand Control Ventilation	E21C3d026	-	-									-	-	-	-
C3d - Muni Direct Install	Door Heater Controls	E21C3d027	-	-									-	-	-	-
C3d - Muni Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C3d028	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Electric	E21C3d029	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Gas	E21C3d030	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Oil	E21C3d031	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Propane	E21C3d032	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Electric	E21C3d033	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Gas	E21C3d034	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Oil	E21C3d035	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Propane	E21C3d036	-	-									-	-	-	-
C3d - Muni Direct Install	Ductless Mini Split Heat Pump	E21C3d037	-	-									-	-	-	-
C3d - Muni Direct Install	ECM Evaporator Fan Motors for Walk-in Cooler/Freeze	E21C3d038	-	-									-	-	-	-
C3d - Muni Direct Install	Electronic Defrost Control	E21C3d039	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Management System, Electric	E21C3d040	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Electric	E21C3d041	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Gas	E21C3d042	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Oil	E21C3d043	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Propane	E21C3d044	-	-									-	-	-	-
C3d - Muni Direct Install	Evaporator Fan Control	E21C3d045	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Electric	E21C3d046	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Gas	E21C3d047	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Oil	E21C3d048	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Propane	E21C3d049	-	-									-	-	-	-
C3d - Muni Direct Install	Hotel Occupancy Sensor	E21C3d050	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Electric	E21C3d051	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Gas	E21C3d052	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Oil	E21C3d053	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Propane	E21C3d054	-	-									-	-	-	-
C3d - Muni Direct Install	Low Pressure Drop Filter	E21C3d055	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Electr	E21C3d056	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Gas	E21C3d057	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Oil	E21C3d058	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valve, Propa	E21C3d059	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Electric	E21C3d060	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Gas	E21C3d061	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Oil	E21C3d062	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Propane	E21C3d063	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Open Drip	E21C3d064	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Totally Enclosed Fan Cooled	E21C3d065	-	-									-	-	-	-
C3d - Muni Direct Install	Novelty Cooler Shutoff	E21C3d066	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Electric	E21C3d067	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Gas	E21C3d068	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Oil	E21C3d069	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Propane	E21C3d070	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Electric	E21C3d071	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Gas	E21C3d072	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Oil	E21C3d073	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Propane	E21C3d074	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Pre Rinse Spray Valve, Electric	E21C3d075	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Gas	E21C3d076	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Oil	E21C3d077	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Propane	E21C3d078	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Electric	E21C3d079	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Gas	E21C3d080	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Oil	E21C3d081	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Propane	E21C3d082	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Electric	E21C3d083	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Gas	E21C3d084	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Oil	E21C3d085	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Propane	E21C3d086	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive	E21C3d087	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive with Motor	E21C3d088	-	-									-	-	-	-
C3d - Muni Direct Install	Vending Miser	E21C3d089	-	-									-	-	-	-
C3d - Muni Direct Install	Zero Loss Condensate Drain	E21C3d090	-	-									-	-	-	-
	Municipal Energy Solutions Subtotal				**288.3**	**292.8**	**3,278.8**	**3,311.3**	**43.7**	**44.2**	**11.1**	**11.4**	**260.7**	**258.2**	**7,159.2**	**7,135.2**

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
2022 System Benefits Charge ("SBC") Calculation

Year	EE Total Budget	RGGI Revenues	FCM Revenues	Carryforward with Interest	Current Year Interest	SBC Requirement	Forecasted Distribution (MWH)	SBC Rate EE Portion (cents/kWh)	SBC Rate LBR (cents/kWh)	SBC Rate EAP Portion (cents/kWh)	2022 Total SBC Rate (cents/kWh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2022	$4,178,747	$207,105	$550,278	$0	$4,134	$3,421,365	917,256	0.528	0.114	0.150	0.792

Effective year (January 1, 2022 - December 31, 2022)
Company Forecast
Company Forecast
Company Forecast
Company Forecast Carryforward
Page 2, Line 11 Column P
Col. B - Col. C - Col. D - Col. E - Col. F
Company Forecast
Per Order No. 26,579
Page 4 line 12
EAP Portion of SBC Rate
Col. I + J

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Energy Efficiency Expense & SBC Revenue Reconcilliation
January 1, 2021 to December 31, 2021

Line	Description	Carryover 2018-2020	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Actual Jul-21	Actual Aug-21	Actual Sep-21	Actual Oct-21	Actual Nov-21	Actual Dec-21	2021 Total
	Col. A	Col. B	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P
1	SBC Revenues		$421	$400	$402	$372	$331	$411	$455	$441	$446	$356	$339	$391	$4,763
2	RGGI Revenues		$0	$0	$54	$0	$0	$54	$0	$0	$54	$0	$0	$54	$217
3	FCM Revenues		$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$599
4	Carryover	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	**Total Revenues**		**$471**	**$450**	**$506**	**$422**	**$380**	**$515**	**$505**	**$491**	**$550**	**$406**	**$388**	**$495**	**$5,579**
6	Program Expenses		$38	$145	$443	$437	$234	$480	$393	$374	$547	$518	$169	$1,612	$5,390
7	**Total Program Expenses**		**$38**	**$145**	**$443**	**$437**	**$234**	**$480**	**$393**	**$374**	**$547**	**$518**	**$169**	**$1,612**	**$5,390**
8	Current Month (Over)/Under Recovery		($433)	($304)	($64)	$15	($147)	($35)	($111)	($117)	($3)	$112	($219)	$1,117	($188)
9	Cumulative (Over)/Under Recovery		($433)	($737)	($801)	($786)	($933)	($968)	($1,079)	($1,196)	($1,199)	($1,087)	($1,306)	($188)	
10	Interest @ Prime		0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
11	**Interest on Deferral Balance**		**($1)**	**($2)**	**($2)**	**($2)**	**($2)**	**($3)**	**($3)**	**($3)**	**($3)**	**($3)**	**($3)**	**($2)**	**($29)**
12	**Monthly Sales (MWh)**		79,723	75,719	76,145	70,406	62,602	77,807	86,118	83,515	84,446	67,476	64,123	73,977	902,058
13	**EE SBC Rate**		0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	

Line 1: Actual data
Line 2: Actual data
Line 3: Actual data
Line 4: Actual data
Line 5: Sum of Lines 1 through Lines 4
Line 6: Company data
Line 7: Sum of Line 6
Line 8: Line 5 - Line 7
Line 9: Prior month Line 9 + Current month Line 8
Line 10 : Prime Rate / 12
Line 11 : (Prior Month Line 9 + Current Month Line 9) / 2 x Line 10
Line 12 : Company Forecast
Line 13 : Page 1, Col. I

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Energy Efficiency Expense & SBC Revenue Reconcilliation
January 1, 2022 to December 31, 2022

Line	Description	Actual Jan-22	Forecast Feb-22	Forecast Mar-22	Forecast Apr-22	Forecast May-22	Forecast Jun-22	Forecast Jul-22	Forecast Aug-22	Forecast Sep-22	Forecast Oct-22	Forecast Nov-22	Forecast Dec-22	2022 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. M	Col. N	Col. O
1	SBC Revenues	$297	$265	$399	$364	$379	$413	$462	$463	$392	$383	$380	$413	$4,610
2	RGGI Revenues	$0	$0	$52	$0	$0	$52	$0	$0	$52	$0	$0	$52	$207
3	FCM Revenues	$46	$46	$46	$46	$46	$46	$46	$46	$46	$46	$46	$46	$550
4	Carryover	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	**Total Revenues**	**$343**	**$311**	**$496**	**$410**	**$425**	**$511**	**$508**	**$508**	**$490**	**$429**	**$426**	**$510**	**$5,367**
6	Program Expenses	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$5,367
7	**Total Program Expenses**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$447**	**$5,367**
8	Current Month (Over)/Under Recovery	$105	$136	($49)	$38	$22	($63)	($61)	($61)	($43)	$18	$21	($63)	
9	Cumulative (Over)/Under Recovery	$105	$241	$192	$229	$251	$188	$127	$66	$23	$42	$63	$0	
10	Interest @ Prime	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
11	**Interest on Deferral Balance**	**$0**	**$0**	**$1**	**$1**	**$1**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$4**
12	**Monthly Sales (MWh)**	79,594	71,077	75,532	68,916	71,833	78,205	87,509	87,595	74,311	72,522	72,037	78,125	917,256
13	**EE SBC Rate**	0.373	0.373	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	

Line 1: Forecast data
Line 2: Forecast data
Line 3: Forecast data
Line 4: Forecast data
Line 5: Sum of Lines 1 through Lines 4
Line 6: Company data
Line 7: Sum of Line 6
Line 8: Line 5 - Line 7
Line 9: Prior month Line 9 + Current month Line 8
Line 10 : Prime Rate / 12
Line 11 : (Prior Month Line 9 + Current Month Line 9) / 2 x Line 10
Line 12 : Company Forecast
Line 13 : Page 1, Col. I

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Lost Base Revenue Reconciliation
January 1, 2019 to December 31, 2020

Line	Description	Cumulative 2019 kWh	Cumulative 2020 kWh	Balance Carryover 12/31/2019	Collections 2020	Forecast May-22	Forecast Jun-22	Forecast Jul-22	Forecast Aug-22	Forecast Sep-22	Forecast Oct-22	Forecast Nov-22	Forecast Dec-22	Total
	Col. A	Col. B	Col. C	Col. D		Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	
1	Revenue Recovery				($5,323)									($5,323)
2	Monthly Residential kWh	280,805	220,322			$29,434	$29,434	$29,434	$29,434	$29,434	$29,434	$29,434	$29,434	235,475
3	Monthly Commercial kWh	872,240	1,354,555			$33,911	$33,911	$33,911	$33,911	$33,911	$33,911	$33,911	$33,911	271,291
4	Monthly Commercial Kw	113	143			$2,366	$2,366	$2,366	$2,366	$2,366	$2,366	$2,366	$2,366	$18,931
5	Total					$60,389	$65,712	$65,712	$65,712	$65,712	$65,712	$65,712	$65,712	520,374
6	Monthly (Over)/Under Recovery					$60,389	$65,712	$65,712	$65,712	$65,712	$65,712	$65,712	$65,712	$520,374
7	Cumulative (Over)/Under Recovery			$180,238		$240,627	$306,339	$372,051	$437,763	$503,476	$569,188	$634,900	$700,612	$700,612
8	Interest @ Prime Rate					0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
9	Interest on Deferral Balance					$570	$741	$919	$1,097	$1,275	$1,453	$1,631	$1,809	$9,492
10	Cummulative (Over)/Under Recovery Incl Carrying Charge					$241,197	$307,650	$374,281	$441,089	$508,076	$575,241	$642,583	$710,104	$710,104
11	Monthly Sales					71,833	78,205	87,509	87,595	74,311	72,522	72,037	78,125	622,136
12	LBR Rate													$0.00114

Line 1: Actual Revenues Jan-Jul. LBR rate was not approved for 2020, thus no LBR revenues forcasted Aug-Dec
Line 2: Col B + Col C x pg 6 line 27
Line 3: Line 2 - Line 1
Line 4: Prior month Line 4 + Current month Line 3
Line 5: Prime Rate / 12
Line 6: (Prior Month Line 4 + Current Month Line 4) / 2 x Line 5
Line 7: Line 4 + line 6
Line 8: Company Forecast

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Calculation of Forecasted Average Distribution Rate for Lost Revenue
Based on Actual Billing Determinants for 2018*

For the Period 01/01/21 Through 12/31/21

	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6) = (1) + (4)	(7) = (2) / (5)	(8) = (3) / (5)
	Revenue							
Rate Class	Demand Charges[a]	kWh Charges	Total Demand and kWh Charges	Delivery kW	Delivery kWh	Average Distribution Rate $/kW	Average Distribution Rate $/kWh	Average Distribution Rate $/kWh
Rate D	$ -	$ 13,224,848	$ 13,224,848	$ -	225,156,209	**N/A**	**N/A**	**$ 0.05874**
Rate D-10	$ -	$ 262,022	$ 262,022	$ -				
Rate T	$ -	$ 15,943,826	$ 15,943,826	$ -				
Total Residential	$ -	$ 29,430,697	$ 29,430,697	$ -				
Rate G-1	$ 8,806,756	$ 1,422,025	$ 10,228,781	951,329	316,780,437	$ 9.26	$ 0.00449	$ 0.03229
Rate G-2	$ -	$ 2,284,972	$ 2,284,972	-	147,995,065	$ -	$ 0.01544	$ 0.01544
Rate G-3	$ -	$ 4,699,561	$ 4,699,561	-	88,095,304	$ -	$ 0.05335	$ 0.05335
Rate V	$ -	$ 17,988	$ 17,988	-	328,389	$ -	$ 0.05478	$ 0.05478
Total Commercial and Industrial	$ 8,806,756	$ 8,424,546	$ 17,231,302	951,329	553,199,195	**$ 9.26**	**$ 0.01523**	**$ 0.03115**

* Excludes the outdoor lighting Rate OL and the Customer/Meter charge revenue from each rate. Used billing determinants from DE 19-064
(a) For Rate G-2, the demand charge is excluded from the average rate calculation

Bill Impacts of Changes in System Benefits Charge - Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities

	Current Rates*	2022 Res	2022 C&I
System Benefits Charge ($/kWh)	$0.00678	$0.00792	$0.00792
Bill per month, including GSE default energy service			
Residential Rate D (650 kWh/month)	$154.56	$155.30	
Rate G-2, 25 kW, 9,000 kWh per month	$1,282.09		$1,293.50
Change from previous rate level - $ per month			
Residential Rate D (650 kWh/month)		$0.74	
Rate G-2, 25 kW, 9,000 kWh per month			$11.41
Change from previous rate level - %			
Residential Rate D (650 kWh/month)		0.48%	
Rate G-2, 25 kW, 9,000 kWh per month			0.89%

* Stated at Liberty's most recent rate levels (effective March 1, 2022). Rate G-2 energy service rate is based on March 1, 2022 rate.

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Calculation of Distribution Revenue at the Rate Levels in Effect During 2021
Based on Billing Determinants for the Twelve Months Ending December 2018

Residential Rate D

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	141,213	$ 14.67	$ 2,071,595	70,576	$ 14.74	$ 1,040,290	141,727	$ 14.74	$ 2,089,056	71,051	$ 14.74	$1,047,292	424,567	$ 6,248,233
	All kWh	95,419,680	$0.05713	$ 5,451,326	39,012,006	$0.05805	$ 2,264,647	44,198,243	$0.06086	$ 2,689,905	44,198,243	$0.06102	$2,696,977	222,828,172	$13,102,855
Off Peak kWh 16 Hour	All kWh	425,641	$0.04934	$ 21,001	168,850	$0.05021	$ 8,478	179,422	$0.05264	$ 9,445	179,422	$0.05277	$ 9,468	953,335	$ 48,392
Farm kWh	All kWh	336,408	$0.05393	$ 18,142	136,211	$0.05483	$ 7,468	113,878	$0.05748	$ 6,546	113,878	$0.05763	$ 6,563	700,375	$ 38,719
D-6 kWh	All kWh	285,950	$0.05025	$ 14,369	130,531	$0.05113	$ 6,674	128,923	$0.05360	$ 6,910	128,923	$0.05374	$ 6,928	674,327	$ 34,882
Total Residential	Customer/Meter	141,213		$ 2,071,595	70,576		$ 1,040,290	141,727		$ 2,089,056	71,051		$1,047,292	495,618	$ 6,248,233
	Demand	-		-	-		-	-		-	-		-	-	-
	kWh	96,467,679		$ 5,504,839	39,447,598		$ 2,287,267	44,620,466		$ 2,712,806	44,620,466		$2,719,936	225,156,209	$13,224,848
				$ 7,576,434			$ 3,327,558			$ 4,801,862			$3,767,228		$19,473,081

Residential Rate D-10

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Col. B - Col. C - Col. D - Col. E - Col. F	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	1,763	$ 14.67	$ 25,863	879	$ 14.74	$ 12,956	1,759	$ 14.74	$ 25,928	876	$ 14.74	$ 12,912	5,277	$ 77,660
	On Peak kWh	819,396	$0.12151	$ 99,565	264,793	$0.12279	$ 32,514	621,216	$0.12841	$ 79,770	332,213	$0.12873	$ 42,766	2,037,618	$ 254,615
	Off Peak kWh	1,647,511	$0.00173	$ 2,850	439,551	$0.00229	$ 1,007	861,926	$0.00236	$ 2,034	642,673	$0.00236	$ 1,517	3,591,661	$ 7,408
Total Rate D-10	Customer/Meter	1,763		$ 25,863	879		$ 12,956	1,759		$ 25,928	876		$ 12,912	5,277	$ 77,660
	Demand	-		$ -	-		$ -	-		$ -	-		$ -	-	$ -
	kWh	2,466,907		$ 102,415	704,344		$ 33,521	1,483,142		$ 81,804	974,886		$ 44,282	5,629,279	$ 262,022
				$ 128,278			$ 46,477			$ 107,732			$ 57,195		$ 339,682

Commercial & Industrial Rate G-1

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	533	$ 426.78	$ 227,474	279	$ 428.73	$ 119,616	561	$ 443.84	$ 248,994	284	$ 444.70	$ 126,295	1,657	$ 722,378
	Demand Charge	293,661	$ 9.06	$ 2,660,569	158,070	$ 9.10	$ 1,438,437	345,908	$ 9.42	$ 3,258,453	153,690	$ 9.43	$1,449,297	951,329	$ 8,806,756
	On Peak kWh	64,013,730	$0.00588	$ 376,401	36,141,242	$0.00646	$ 233,472	79,011,715	$0.00666	$ 526,218	33,339,415	$0.00667	$ 222,374	212,506,102	$ 1,358,465
	Off Peak kWh	48,788,724	$0.00180	$ 87,820	29,394,681	$0.00236	$ 69,371	861,926	$0.00242	$ 2,086	24,874,655	$0.00242	$ 60,197	103,919,986	$ 219,474
	Credit for High Voltage Delivery	90,841	$ (0.44)	$ (39,970)	86,717	$ (0.44)	$ (38,155)	123,591	$ (0.44)	$ (54,380)	53,200	$ (0.44)	$ (23,408)	354,349	$ (155,914)
Total Rate G-1	Customer/Meter	533		$ 227,474	279		$ 119,616	561		$ 248,994	284		$ 126,295	1,657	$ 722,378
	Demand	293,661		$ 2,660,569	158,070		$ 1,438,437	345,908		$ 3,258,453	153,690		$1,449,297	951,329	$ 8,806,756
	kWh	112,893,295		$ 424,250	65,622,640		$ 264,688	79,997,232		$ 473,924	58,267,270		$ 259,163	316,780,437	$ 1,422,025
				$ 3,312,293			$ 1,822,741			$ 3,981,371			$1,834,754		$10,951,159

Commercial Rate G-2

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	3,621	$ 71.14	$ 257,598	1,817	$ 71.46	$ 129,843	3,642	$ 73.97	$ 269,399	1,802	$ 74.14	$ 133,600	10,882	$ 790,440
	Demand Charge	163,850	$ 9.11	$ 1,492,674	86,590	$ 9.15	$ 792,299	179,113	$ 9.47	$ 1,696,200	80,555	$ 9.48	$ 763,661	510,108	$ 4,744,834
	All kWh	48,549,883	$0.00238	$ 115,549	24,347,591	$0.00295	$ 71,825	52,596,078	$0.00303	$ 159,366	22,499,564	$0.00303	$ 68,174	147,993,116	$ 414,914
	Credit for High Voltage Delivery	577	$ (0.44)	$ (254)	302	$ (0.44)	$ (133)	683	$ (0.44)	$ (301)	387	$ (0.44)	$ (170)	1,949	$ (858)
Total Rate G-2	Customer/Meter	3,621		$ 257,598	1,817		$ 129,843	3,642		$ 269,399	1,802		$ 133,600	10,882	$ 387,441
	Demand	163,850		$ 1,492,674	86,590		$ 792,299	179,113		$ 1,696,200	80,555		$ 763,661	510,108	$ 2,284,972
	kWh	48,550,460		$ 115,295	24,347,893		$ 71,693	52,596,761		$ 159,066	22,499,951		$ 68,003	147,995,065	$ 186,987
				$ 1,865,566			$ 993,834			$ 2,124,664			$ 965,265		$ 2,859,400

General Service Rate G-3

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	22,671	$ 16.36	$ 370,898	11,288	$ 16.43	$ 185,462	22,698	$ 17.00	$ 385,866	11,383	$ 17.03	$ 193,852	68,040	$ 1,136,078
	All kWh	30,521,195	$0.05190	$ 1,584,050	13,568,301	$0.05269	$ 714,914	30,002,948	$0.05452	$ 1,635,761	14,002,860	$0.05462	$ 764,836	88,095,304	$ 4,699,561
Total Rate G-3	Customer/Meter	22,671		$ 370,898	11,288		$ 185,462	22,698		$ 385,866	11,383		$ 193,852	68,040	$ 1,136,078
	Demand	-		$ -	-		$ -	-		$ -	-		$ -	-	$ -
	kWh	30,521,195		$ 1,584,050	13,568,301		$ 714,914	30,002,948		$ 1,635,761	14,002,860		$ 764,836	88,095,304	$ 4,699,561
				$ 1,954,948			$ 900,376			$ 2,021,627			$ 958,689		$ 5,835,639

Electric Heat Rate T

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	3,898	$ 14.67	$ 57,184	1,935	$ 14.74	$ 28,522	3,832	$ 14.74	$ 56,484	1,901	$ 14.74	$ 28,021	11,566	$ 170,210
	All kWh	7,115,111	$0.04639	$ 330,070	1,821,872	$0.04721	$ 86,011	3,567,675	$0.04924	$ 175,672	2,847,415	$0.04935	$ 140,520	15,352,073	$15,943,826
Total Rate T	Customer/Meter	3,898		$ 57,184	1,935		$ 28,522	3,832		$ 56,484	1,901		$ 28,021	11,566	$ 170,210
	Demand	-		$ -	-		$ -	-		$ -	-		$ -	-	$ -
	kWh	7,115,111		$ 330,070	1,821,872		$ 86,011	3,567,675		$ 175,672	2,847,415		$ 140,520	15,352,073	$15,943,826
				$ 387,254			$ 114,532			$ 232,156			$ 168,541		$16,114,036

Electric Heat Rate V

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Rate	Source	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
Standard	Customer Charge	72	$ 16.36	$ 1,178	36	$ 16.43	$ 591	69	$ 17.00	$ 1,173	34	$ 17.03	$ 579	211	$ 3,521
	All kWh	127,747	$0.05338	$ 6,819	44,462	$0.05418	$ 2,409	107,102	$0.05606	$ 6,004	49,078	$0.05616	$ 2,756	328,389	$ 17,988
Total Rate V	Customer/Meter	72		$ 1,178	36		$ 591	69		$ 1,173	34		$ 579	211	$ 3,521
	Demand	-		$ -	-		$ -	-		$ -	-		$ -	-	$ -
	kWh	127,747		$ 6,819	44,462		$ 2,409	107,102		$ 6,004	49,078		$ 2,756	328,389	$ 17,988
				$ 7,997			$ 3,000			$ 7,177			$ 3,335		$ 21,510

Outdoor Lighting Rate OL

		January 1, 2021 - April 30, 2021			May 1, 2021 - June 30, 2021			July 1, 2021 - October 31 ,2021			November 1, 2021 - December 31, 2021			2021 Total	
Type	Fixture	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Rate	Revenue	Units	Revenue
High Pressure Sodium	HPS RWY 50W	8,846	$ 8.39	$ 74,218	5,813	$ 8.42	$ 48,945	7,305	$ 8.71	$ 63,627	7,283	$ 8.72	$ 63,508	29,247	$ 250,298
	HPS RWY 100W	6,320	$ 9.69	$ 61,241	4,534	$ 9.73	$ 44,116	5,440	$ 10.07	$ 54,781	5,487	$ 10.08	$ 55,309	21,781	$ 215,446
	HPS RWY 250W	1,963	$ 16.06	$ 31,526	1,120	$ 16.14	$ 18,077	1,514	$ 16.70	$ 25,284	1,496	$ 16.73	$ 25,028	6,093	$ 99,914
	HPS RWY 400W	754	$ 19.98	$ 15,065	199	$ 20.07	$ 3,994	250	$ 20.77	$ 5,193	227	$ 20.81	$ 4,724	1,430	$ 28,975
	HPS POST 100W	1,240	$ 11.36	$ 14,086	1,192	$ 11.41	$ 13,601	1,210	$ 11.81	$ 14,290	1,206	$ 11.83	$ 14,267	4,848	$ 56,244
	HPS FLD 250W	1,030	$ 16.24	$ 16,727	534	$ 16.31	$ 8,710	759	$ 16.88	$ 12,812	759	$ 16.91	$ 12,835	3,082	$ 51,083
	HPS FLD 400W	1,680	$ 21.69	$ 36,439	864	$ 21.78	$ 18,818	1,250	$ 22.54	$ 28,175	1,250	$ 22.58	$ 28,225	5,044	$ 111,657
Incandescent	INC RWY 103W	92	$ 10.75	$ 989	46	$ 10.79	$ 496	69	$ 11.17	$ 771	69	$ 11.19	$ 772	276	$ 3,028
Mercury	MV RWY 100W	288	$ 7.44	$ 2,143	142	$ 7.47	$ 1,061	201	$ 7.73	$ 1,554	177	$ 7.74	$ 1,370	808	$ 6,127
	MV RWY 175W	570	$ 8.36	$ 4,765	280	$ 8.39	$ 2,349	392	$ 8.68	$ 3,403	333	$ 8.69	$ 2,894	1,575	$ 13,411
	MV RWY 400W	201	$ 14.93	$ 3,001	100	$ 14.99	$ 1,499	150	$ 15.51	$ 2,327	150	$ 15.54	$ 2,331	601	$ 9,157
	MV RWY 1000W	4	$ 25.21	$ 101	2	$ 25.32	$ 51	3	$ 26.21	$ 79	3	$ 26.26	$ 79	12	$ 309
	MV FLD 400W	85	$ 17.08	$ 1,452	42	$ 17.15	$ 720	61	$ 17.75	$ 1,083	60	$ 17.78	$ 1,067	248	$ 4,322
	MV FLD 1000W	-	$ 33.06	$ -	-	$ 33.21	$ -	-	$ 34.38	$ -	-	$ 34.44	$ -	-	$ -
POLES	WOOD	468	$ 9.47	$ 4,432	237	$ 9.51	$ 2,254	343	$ 9.85	$ 3,379	342	$ 9.87	$ 3,376	1,390	$ 13,440
	POLE FIBER DIRECT EMBEDDED	747	$ 9.81	$ 7,328	723	$ 9.92	$ 7,172	735	$ 10.26	$ 7,541	735	$ 10.28	$ 7,556	2,940	$ 29,597
	POLE FIBER RWY <25FT	478	$ 16.65	$ 7,959	412	$ 16.73	$ 6,893	426	$ 17.32	$ 7,378	426	$ 17.35	$ 7,391	1,742	$ 29,621
	POLE FIBER RWY =>25FT	12	$ 27.84	$ 334	12	$ 27.97	$ 336	12	$ 28.95	$ 347	12	$ 29.01	$ 348	48	$ 1,365
	POLE METAL EMBEDDED	568	$ 19.85	$ 11,275	404	$ 19.94	$ 8,056	486	$ 20.64	$ 10,031	486	$ 20.68	$ 10,050	1,944	$ 39,412
	POLE METAL =>25FT	376	$ 23.94	$ 9,001	222	$ 24.05	$ 5,339	296	$ 24.90	$ 7,370	294	$ 24.95	$ 7,335	1,188	$ 29,046
LED	LED 30W	56	$ 5.44	$ 305	28	$ 5.46	$ 153	44	$ 5.65	$ 249	45	$ 5.66	$ 255	173	$ 961
	LED 50W	112	$ 5.67	$ 635	193	$ 5.69	$ 1,098	234	$ 5.89	$ 1,378	240	$ 5.90	$ 1,416	779	$ 4,527
	LED 130W	123	$ 8.75	$ 1,076	382	$ 8.79	$ 3,358	429	$ 9.09	$ 3,900	429	$ 9.10	$ 3,904	1,363	$ 12,238
	LED 190W	13	$ 16.75	$ 218	11	$ 16.82	$ 185	10	$ 17.41	$ 174	9	$ 17.44	$ 157	43	$ 734
	LED 30W URD	42	$ 12.67	$ 532	36	$ 12.72	$ 458	39	$ 13.16	$ 513	39	$ 13.18	$ 514	156	$ 2,017
	LED 90W FLOOD	-	$ 8.62	$ -	-	$ 8.65	$ -	6	$ 8.95	$ 54	11	$ 8.96	$ 99	17	$ 152
	LED 130W FLOOD	-	$ 9.90	$ -	4	$ 9.94	$ 40	14	$ 10.29	$ 144	12	$ 10.31	$ 124	30	$ 308
	LED 50W BARN	-	$ 4.88	$ -	-	$ 4.90	$ -	-	$ 5.07	$ -	2	$ 5.07	$ 10	2	$ 10
	All kWh	-	$0.03993	$ -	-	$0.04067	$ -	-	$0.04208	$ -	-	$0.04216	$ -	-	$ -
Total Rate OL	Fixtures	26,068		$ 304,848	17,532		$ 197,777	21,678		$ 255,834	21,582		$ 254,942	86,860	$ 1,013,401
	Demand														
	kWh	-			-			-			-			-	
				$ 304,848			$ 197,777			$ 255,834			$ 254,942		$ 1,013,401

Total Retail

		January 1, 2021 - April 30, 2021		May 1, 2021 - June 30, 2021		July 1, 2021 - October 31 ,2021		November 1, 2021 - December 31, 2021		2021 Total	
Type	Source	Units	Revenue	Units	Revenue	Units	Revenue	Units	Revenue	Units	Revenue
Total Retail	Customer/Meter	173,771	$ 3,011,788.74	86,810	$ 1,517,280	174,288	$ 3,076,899	87,331	$1,542,551	434,869	$ 7,605,968
	Fixtures	26,068	$ 304,848	17,532	$ 197,777	21,678	$ 255,834	21,582	$ 254,942	65,278	$ 758,459
	Demand	457,511	$ 4,153,242	244,660	$ 2,192,447	525,021	$ 4,899,973	234,245	$2,189,380	1,227,192	$11,245,662
	kWh	298,142,394	$ 8,067,738	145,557,110	$ 3,460,502	212,375,326	$ 5,245,037	143,261,926	$3,999,497	656,074,830	$16,773,277
			$ 15,537,617		$ 7,368,007		$13,477,743		$7,986,370		$36,383,367

Lost Base Revenue
Summary of Data Included in the Calculation of the Average Distribution Rates

		January 1, 2021 - April 30, 2021		May 1, 2021 - June 30, 2021		July 1, 2021 - October 31 ,2021		November 1, 2021 - December 31, 2021		2021 Total	
Type	**Source**	**Units**	**Revenue**	**Units**	**Revenue**	**Units**	**Revenue**	**Units**	**Revenue**	**Units**	**Revenue**
Total Rate D	Demand	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	kWh	96,467,679	$ 5,504,839	39,447,598	$ 2,287,267	44,620,466	$ 2,712,806	44,620,466	$ 2,719,936	180,535,743	$10,504,912
			$ 5,504,839		$ 2,287,267		$ 2,712,806		$ 2,719,936		$10,504,912
Total Rate D-10	Demand		$ -	-	$ -	-	$ -	-	$ -	-	$ -
	kWh	2,466,907	$ 102,415	704,344	$ 33,521	1,483,142	$ 81,804	974,886	$ 44,282	4,654,393	$ 217,740
			$ 102,415		$ 33,521		$ 81,804		$ 44,282		$ 217,740
Total Rate G-1	Demand	293,661	$ 2,660,569	158,070	$ 1,438,437	345,908	$ 3,258,453	153,690	$ 1,449,297	797,639	$ 7,357,459
	kWh	112,893,295	$ 424,250	65,622,640	$ 264,688	79,997,232	$ 473,924	58,267,270	$ 259,163	258,513,167	$ 1,162,863
			$ 3,084,819		$ 1,703,125		$ 3,732,377		$ 1,708,459		$ 8,520,322
Total Rate G-2	Demand	163,850	$ 1,492,674	86,590	$ 792,299	179,113	$ 1,696,200	80,555	$ 763,661	429,553	$ 3,981,172
	kWh	48,550,460	$ 115,295	24,347,893	$ 71,693	52,596,761	$ 159,066	22,499,951	$ 68,003	125,495,114	$ 346,053
			$ 1,607,968		$ 863,991		$ 1,855,266		$ 831,665		$ 4,327,225
Total Rate G-3	Demand	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	kWh	30,521,195	$ 1,584,050	13,568,301	$ 714,914	30,002,948	$ 1,635,761	14,002,860	$ 764,836	74,092,444	$ 3,934,725
			$ 1,584,050		$ 714,914		$ 1,635,761		$ 764,836		$ 3,934,725
Total Rate T	Demand	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	kWh	7,115,111	$ 330,070	1,821,872	$ 86,011	3,567,675	$ 175,672	2,847,415	$ 140,520	12,504,658	$ 591,753
			$ 330,070		$ 86,011		$ 175,672		$ 140,520		$ 591,753
Total Rate V	Demand	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	kWh	127,747	$ 6,819	44,462	$ 2,409	107,102	$ 6,004	49,078	$ 2,756	279,311	$ 15,232
			$ 6,819		$ 2,409		$ 6,004		$ 2,756		$ 15,232
Total	Demand	457,511	$ 4,153,242	39,692,258	$ 2,230,736	45,145,487	$ 4,954,653	44,854,711	$ 2,212,958	1,227,192	$11,338,631
	kWh	267,621,199	$ 6,483,688	131,988,809	$ 2,745,588	182,372,378	$ 3,609,276	129,259,066	$ 3,234,661	581,982,386	$12,838,553
			$ 10,636,930		$ 4,976,324		$ 8,563,930		$ 5,447,619		$24,177,184

Program Cost-Effectiveness - 2022

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.70	1.70	1,715.5	1,715.5	1,008.7	-	181.8	2,571.0	47.2	12.7	71	1,809.0	39,022.8
A1 - Energy Star Homes	5.44	5.75	3,836.9	3,094.5	538.4	166.7	443.5	10,702.9	116.9	4.6	88	2,590.8	63,300.7
A2 - Home Performance with Energy Star	6.54	6.22	7,604.6	6,145.5	988.5	174.2	344.0	6,625.5	113.5	2.2	285	9,523.2	204,672.1
A3 - Energy Star Products	1.96	2.23	2,952.7	2,440.5	1,093.0	416.4	2,624.0	21,449.2	497.8	396.7	29,247	(1,570.9)	2,356.2
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	6.0	-	-	-	-	-	-	-	-
Sub-Total Residential	**3.65**	**3.66**	**16,109.7**	**13,396.0**	**3,659.2**	**757.3**	**3,593.3**	**41,348.6**	**775.4**	**416.1**	**29,691**	**12,352.1**	**309,351.8**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.21	2.87	2,244.4	2,039.7	709.7	1,141.4	2,431.2	28,657.8	474.8	121.4	28	(600.0)	(5,997.5)
C2 - Small Business Energy Solutions	1.07	1.50	1,358.4	1,234.1	823.7	441.5	1,709.5	18,312.4	177.5	109.2	138	(662.6)	(6,706.3)
C3 - Municipal Energy Solutions	0.60	1.09	231.9	210.6	193.7	195.1	302.1	3,021.5	22.1	28.6	16	(195.9)	(1,958.6)
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	14.0	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	14.4	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.09**	**1.98**	**3,834.6**	**3,484.4**	**1,755.5**	**1,778.0**	**4,442.8**	**49,991.7**	**674.3**	**259.1**	**183**	**(1,458.5)**	**(14,662.4)**
C6e - Smart Start	-	-	-	-	-	-	-	-	-	-		-	-
Total	**2.51**	**3.12**	**19,944.3**	**16,880.31**	**5,414.7**	**2,535.3**	**8,036.2**	**91,340.3**	**1,449.7**	**675.3**	**29,875**	**10,893.7**	**294,689.4**

Notes:
(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied
(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.
(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual kWh Savings	8,036,153	71.6%	**kWh > 65%**	**Lifetime** kWh Savings	91,340,304	51.4%	**kWh < 65%**
Annual MMBTU Savings (in kWh)	3,192,617	28.4%		**Lifetime** MMBTU Savings (in kWh)	86,364,942	48.6%	
	11,228,770	100.0%			**177,705,246**	100.0%	

Annual Net Savings as a % of 2019 Sales	1.05%

Spending per Customer	Low-Income	$	416.12
	Residential	$	38.37
	C&I	$	43.45

Present Value Benefits - 2022 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environ-mental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 1,715**	$ 5	$ -	$ 9	$ 10	$ -	$ 65	$ 72	$ 10	$ 9	$ 10	**$ 191**	$ 1,019	$ 2	**$ 1,212**	$ 63	$ 440	**$ 503**	**$ 99**
A1 - Energy Star Homes	**$ 3,095**	$ 4	$ -	$ 6	$ 6	$ -	$ 286	$ 367	$ 5	$ 4	$ 31	**$ 709**	$ 2,260	$ 10	**$ 2,980**	$ 115	$ 742	**$ 857**	**$ 321**
A2 - Home Performance with Energy Star	**$ 6,146**	$ 0	$ -	$ 0	$ 0	$ -	$ 178	$ 231	$ 2	$ 2	$ 22	**$ 436**	$ 5,401	$ -	**$ 5,836**	$ 309	$ 1,459	**$ 1,768**	**$ 213**
A3 - Energy Star Products	**$ 2,440**	$ 139	$ -	$ 253	$ 261	$ -	$ 464	$ 469	$ 181	$ 153	$ 108	**$ 2,027**	$ 22	$ 386	**$ 2,435**	$ 5	$ 512	**$ 518**	**$ 1,011**
Sub-Total Residential	**$ 13,396**	**$ 148**	**$ -**	**$ 268**	**$ 277**	**$ -**	**$ 993**	**$ 1,139**	**$ 198**	**$ 167**	**$ 172**	**$ 3,362**	**$ 8,703**	**$ 399**	**$ 12,463**	**$ 492**	**$ 3,154**	**$ 3,646**	**$ 1,644**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 2,040**	$ 62	$ -	$ 111	$ 114	$ -	$ 641	$ 681	$ 229	$ 156	$ 152	**$ 2,147**	$ (99)	$ -	**$ 2,047**	$ (8)	$ 205	**$ 197**	**$ 1,317**
C2 - Small Business Energy Solutions	**$ 1,234**	$ 51	$ -	$ 92	$ 95	$ -	$ 322	$ 259	$ 258	$ 181	$ 96	**$ 1,354**	$ (111)	$ -	**$ 1,243**	$ (9)	$ 124	**$ 116**	**$ 887**
C3 - Municipal Energy Solutions	**$ 211**	$ 13	$ -	$ 23	$ 24	$ -	$ 61	$ 34	$ 50	$ 25	$ 17	**$ 245**	$ (32)	$ -	**$ 213**	$ (2)	$ 21	**$ 19**	**$ 150**
Sub-Total Commercial & Industrial	**$ 3,484**	**$ 126**	**$ -**	**$ 226**	**$ 233**	**$ -**	**$ 1,023**	**$ 974**	**$ 537**	**$ 362**	**$ 265**	**$ 3,746**	**$ (243)**	**$ -**	**$ 3,503**	**$ (19)**	**$ 350**	**$ 332**	**$ 2,353**
Total	**$ 16,880**	**$ 274**	**$ -**	**$ 494**	**$ 510**	**$ -**	**$ 2,017**	**$ 2,113**	**$ 735**	**$ 529**	**$ 437**	**$ 7,108**	**$ 8,460**	**$ 399**	**$ 15,966**	**$ 474**	**$ 3,504**	**$ 3,978**	**$ 3,997**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2022

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	91,340,304	*68,505,228*		-	1.540%	-	$ 83,387	*$ 104,234*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	8,036,153	*6,027,115*		-	0.440%	-	$ 23,825	*$ 29,781*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	675	*439*		-	0.528%	-	$ 28,590	*$ 35,737*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	1,450	*942*		-	0.352%	-	$ 19,060	*$ 23,825*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 15,966,347			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 5,414,728			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 10,551,619	*$ 7,913,714*	$ -	-	1.540%	-	$ 83,387	*$ 104,234*	$ -	Line 5 minus line 6
9	Total					4.400%	-	$ 238,248	*$ 297,810*	$ -	

		Granite State Test		
		Planned	Actual	Source
10	Total Benefits	$ 16,880,305		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 238,248	$ -	from row 9 above
12	Total Utility Costs	$ 5,414,728	$ -	from row 7 above
13	**Portfolio GST BCR**	**2.99**	**-**	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

[2] Net of Smart Start

Program Cost-Effectiveness - 2023

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.80	1.80	1,475.3	1,475.3	821.2	-	160.2	2,253.4	40.6	11.4	71	1,496.1	32,230.0
A1 - Energy Star Homes	5.41	5.62	2,930.8	2,364.8	421.0	121.0	332.3	8,019.8	96.4	3.4	66	1,941.3	47,432.2
A2 - Home Performance with Energy Star	6.52	6.06	4,820.7	3,897.7	643.1	95.8	218.4	3,876.6	71.8	1.2	225	6,094.1	125,641.5
A3 - Energy Star Products	1.98	2.16	2,282.4	1,878.5	868.3	284.7	1,631.4	16,029.1	323.6	239.4	15,931	(257.2)	6,194.3
A5 - Residential Active Demand Response	-	-	-	-	-	-	-	-	-	-		-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	5.8	-	-	-	-	-	-	-	-
Sub-Total Residential	**3.51**	**3.46**	**11,509.2**	**9,616.4**	**2,782.2**	**501.5**	**2,342.3**	**30,178.9**	**532.3**	**255.4**	**16,294**	**9,274.2**	**211,498.0**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.27	2.72	1,625.7	1,477.4	544.0	738.9	1,684.8	20,122.6	326.5	86.3	21	(392.6)	(3,924.0)
C2 - Small Business Energy Solutions	1.11	1.48	1,016.4	923.4	625.7	292.8	1,249.2	13,389.5	129.4	79.6	107	(481.6)	(4,874.0)
C3 - Municipal Energy Solutions	0.60	1.01	177.3	161.0	158.7	135.3	225.9	2,259.2	16.5	21.4	13	(146.4)	(1,464.4)
C5 - C&I Active Demand Response	-	-	-	-	-	-	-	-	-	-		-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	13.6	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	13.4	-	-	-	-	-	-	-	-
C6d - C&I Customer Partnerships	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.12**	**1.89**	**2,819.4**	**2,561.8**	**1,355.3**	**1,167.0**	**3,160.0**	**35,771.3**	**472.4**	**187.2**	**140**	**(1,020.6)**	**(10,262.4)**
C6e - Smart Start	-	-	-	-	-	-	-	-	-	-		-	-
Total	**2.47**	**2.94**	**14,328.7**	**12,178.2**	**4,137.5**	**1,668.5**	**5,502.3**	**65,950.2**	**1,004.8**	**442.6**	**16,434**	**8,253.7**	**201,235.6**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2023.

Annual kWh Savings	5,502,305	69.46%	**kWh > 65%**	**Lifetime** kWh Savings	65,950,197	52.8%
Annual MMBTU Savings (in kWh)	2,418,908	30.5%		**Lifetime** MMBTU Savings (in kWh)	58,976,331	47.2%
	7,921,213	100.0%			**124,926,527**	100.0%

Annual Net Savings as a % of 2019 Sales	0.72%

Spending per Customer	Low-Income	$ 338.77
	Residential	$ 28.39
	C&I	$ 33.55

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environmental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 1,475**	$ 5	$ -	$ 9	$ 9	$ -	$ 58	$ 64	$ 10	$ 8	$ 9	**$ 172**	$ 874	$ 2	**$ 1,048**	$ 56	$ 371	**$ 427**	**$ 84**
A1 - Energy Star Homes	**$ 2,365**	$ 3	$ -	$ 5	$ 5	$ -	$ 209	$ 268	$ 4	$ 3	$ 23	**$ 518**	$ 1,745	$ 8	**$ 2,271**	$ 93	$ 566	**$ 659**	**$ 218**
A2 - Home Performance with Energy Star	**$ 3,898**	$ 0	$ -	$ 0	$ 0	$ -	$ 107	$ 139	$ 1	$ 1	$ 14	**$ 262**	$ 3,430	$ -	**$ 3,692**	$ 206	$ 923	**$ 1,129**	**$ 122**
A3 - Energy Star Products	**$ 1,879**	$ 100	$ -	$ 179	$ 185	$ -	$ 355	$ 375	$ 127	$ 109	$ 76	**$ 1,507**	$ 109	$ 253	**$ 1,869**	$ 10	$ 404	**$ 414**	**$ 685**
Sub-Total Residential	**$ 9,616**	**$ 108**	**$ -**	**$ 193**	**$ 199**	**$ -**	**$ 729**	**$ 846**	**$ 142**	**$ 121**	**$ 122**	**$ 2,459**	**$ 6,158**	**$ 263**	**$ 8,880**	**$ 366**	**$ 2,264**	**$ 2,629**	**$ 1,109**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 1,477**	$ 48	$ -	$ 84	$ 87	$ -	$ 453	$ 484	$ 169	$ 117	$ 107	**$ 1,550**	$ (67)	$ -	**$ 1,483**	$ (5)	$ 148	**$ 143**	**$ 882**
C2 - Small Business Energy Solutions	**$ 923**	$ 38	$ -	$ 68	$ 71	$ -	$ 241	$ 194	$ 195	$ 136	$ 72	**$ 1,014**	$ (83)	$ -	**$ 930**	$ (7)	$ 93	**$ 86**	**$ 624**
C3 - Municipal Energy Solutions	**$ 161**	$ 10	$ -	$ 18	$ 18	$ -	$ 46	$ 26	$ 38	$ 19	$ 13	**$ 188**	$ (25)	$ -	**$ 163**	$ (2)	$ 16	**$ 14**	**$ 108**
Sub-Total Commercial & Industrial	**$ 2,562**	**$ 95**	**$ -**	**$ 170**	**$ 175**	**$ -**	**$ 740**	**$ 704**	**$ 402**	**$ 272**	**$ 192**	**$ 2,752**	**$ (176)**	**$ -**	**$ 2,576**	**$ (14)**	**$ 258**	**$ 243**	**$ 1,614**
Total	**$ 12,178**	**$ 203**	**$ -**	**$ 363**	**$ 374**	**$ -**	**$ 1,468**	**$ 1,550**	**$ 544**	**$ 393**	**$ 314**	**$ 5,211**	**$ 5,983**	**$ 263**	**$ 11,456**	**$ 351**	**$ 2,521**	**$ 2,873**	**$ 2,722**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 36,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2023

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	65,950,197	*49,462,648*		-	1.540%	-	$ 63,717	*$ 79,647*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	5,502,305	*4,126,729*		-	0.440%	-	$ 18,205	*$ 22,756*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	443	*288*		-	0.528%	-	$ 21,846	*$ 27,307*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	1,005	*653*		-	0.352%	-	$ 14,564	*$ 18,205*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 11,455,909			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 4,137,494			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 7,318,415	*$ 5,488,811*	$ -	-	1.540%	-	$ 63,717	*$ 79,647*	$ -	Line 5 minus line 6
9	Total					4.400%	-	$ 182,050	*$ 227,562*	$ -	

		Granite State Test		
		Planned	**Actual**	**Source**
10	Total Benefits	$ -		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 182,050	$ -	from row 9 above
12	Total Utility Costs	$ 4,137,494	$ -	from row 7 above
13	**Portfolio GST BCR**	**0.00**	**-**	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $234,957.96.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

[2] Net of Smart Start

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
B1a - HEA (Weatherization	Air Sealing, Cord Wood	E21B1a001	-	50	41		-	-		-	-		-	-		-	-	-	43.5	35.9	-	652.1	538.7
B1a - HEA (Weatherization	Air Sealing, Electric	E21B1a002	-	50	41		20.4	16.8		305.3	252.2		6.5	5.3		-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Kerosene	E21B1a004	-	50	41		-	-		-	-		-	-		-	-	-	105.2	86.9	-	1,578.5	1,304.0
B1a - HEA (Weatherization	Air Sealing, Oil	E21B1a005	-	50	41		-	-		-	-		-	-		-	-	-	205.9	170.1	-	3,089.2	2,552.0
B1a - HEA (Weatherization	Air Sealing, Propane	E21B1a006	-	50	41		-	-		-	-		-	-		-	-	-	46.0	38.0	-	689.9	569.9
B1a - HEA (Weatherization	Faucet Aerator, Electric	E21B1a009	-	24	20		3.1	2.5		21.4	17.7		0.6	0.5		0.2	0.2	-	-	-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Oil	E21B1a012	-	24	20		-	-		-	-		-	-		-	-	-	2.0	1.6	-	14.0	11.5
B1a - HEA (Weatherization	Faucet Aerator, Propane	E21B1a013	-	24	20		-	-		-	-		-	-		-	-	-	2.1	1.7	-	14.6	12.1
B1a - HEA (Weatherization	Insulation, Cord Wood	E21B1a022	-	58	48		-	-		-	-		-	-		-	-	-	146.5	121.0	-	3,661.9	3,025.2
B1a - HEA (Weatherization	Insulation, Electric	E21B1a023	-	58	48		40.5	33.4		1,011.8	835.9		12.8	10.6		-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Insulation, Kerosene	E21B1a025	-	58	48		-	-		-	-		-	-		-	-	-	147.4	121.7	-	3,684.4	3,043.7
B1a - HEA (Weatherization	Insulation, Oil	E21B1a026	-	58	48		-	-		-	-		-	-		-	-	-	422.7	349.2	-	10,568.0	8,730.4
B1a - HEA (Weatherization	Insulation, Propane	E21B1a027	-	58	48		-	-		-	-		-	-		-	-	-	259.5	214.4	-	6,487.5	5,359.4
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Electric	E21B1a037	-	12	10		1.8	1.5		26.4	21.8		0.3	0.3		0.1	0.1	-	-	-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Kerosene	E21B1a039	-	12	10		-	-		-	-		-	-		-	-	-	(1.4)	(1.2)	-	(21.6)	(17.8)
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Oil	E21B1a040	-	12	10		-	-		-	-		-	-		-	-	-	56.5	46.7	-	847.7	700.3
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Propane	E21B1a041	-	12	10		-	-		-	-		-	-		-	-	-	(0.1)	(0.1)	-	(2.0)	(1.6)
B1a - HEA (Weatherization	DHW Heat Pump Water Heater	E21B1a043	-	35	35		57.9	57.9		752.7	752.7		9.5	9.5		5.3	5.3	-	-	-	-	-	-
B1a - HEA (Weatherization	LED Bulb, General Service Lamps	E21B1a044	-	47	39		24.7	20.4		49.5	40.9		5.3	4.4		3.4	2.8	-	(56.2)	(46.4)	-	(112.4)	(92.8)
B1a - HEA (Weatherization	LED Fixture	E21B1a048	-	23	19		4.9	4.0		9.7	8.0		1.0	0.9		0.7	0.6	-	(11.0)	(9.1)	-	(22.1)	(18.2)
B1a - HEA (Weatherization	Refrigerator	E21B1a049	-	20	16		20.9	17.2		250.3	206.8		2.4	2.0		2.9	2.4	-	-	-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Cord Wood	E21B1a055	-	23	19		-	-		-	-		-	-		-	-	-	27.6	22.8	-	691.0	570.8
B1a - HEA (Weatherization	Window Replacement, Electric	E21B1a064	-	23	19		2.2	1.8		55.2	45.6		0.7	0.6		-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Kerosene	E21B1a066	-	23	19		-	-		-	-		-	-		-	-	-	10.9	9.0	-	273.2	225.7
B1a - HEA (Weatherization	Window Replacement, Oil	E21B1a067	-	23	19		-	-		-	-		-	-		-	-	-	30.6	25.3	-	764.3	631.4
B1a - HEA (Weatherization	Window Replacement, Propane	E21B1a068	-	23	19		-	-		-	-		-	-		-	-	-	13.7	11.3	-	341.8	282.3
B1a - HEA (Weatherization	Insulated Door, Cord Wood	E21B1a070	-	23	19		-	-		-	-		-	-		-	-	-	3.0	2.4	-	74.0	61.2
B1a - HEA (Weatherization	Insulated Door, Electric	E21B1a071	-	23	19		0.4	0.3		10.3	8.5		0.1	0.1		-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Kerosene	E21B1a073	-	23	19		-	-		-	-		-	-		-	-	-	3.4	2.8	-	85.6	70.7
B1a - HEA (Weatherization	Insulated Door, Oil	E21B1a074	-	23	19		-	-		-	-		-	-		-	-	-	8.7	7.2	-	217.0	179.3
B1a - HEA (Weatherization	Insulated Door, Propane	E21B1a075	-	23	19		-	-		-	-		-	-		-	-	-	3.2	2.6	-	79.9	66.0
B1b - HEA (HVAC Systems	Boiler Replacement, Oil	E21B1b003	-	4	2		-	-		-	-		-	-		-	-	-	68.6	39.3	-	1,304.0	747.2
B1b - HEA (HVAC Systems	Furnace Replacement, Kerosene	E21B1b006	-	4	2		0.3	0.2		5.6	3.2		0.1	0.1		-	-	-	-	19.0	-	-	322.8
B1b - HEA (HVAC Systems	Programmable Thermostat, Electric	E21B1b009	-	21	18		4.9	4.0		72.8	60.2		7.7	6.4		-	-	-	-	-	-	-	-
B1b - HEA (HVAC Systems	Programmable Thermostat, Kerosene	E21B1b011	-	21	18		-	-		-	-		-	-		-	-	-	67.7	55.9	-	1,015.5	839.0
B1b - HEA (HVAC Systems	Programmable Thermostat, Oil	E21B1b012	-	21	18		-	-		-	-		-	-		-	-	-	67.7	55.9	-	1,015.5	839.0
B1b - HEA (HVAC Systems	Programmable Thermostat, Propane	E21B1b013	-	21	18		-	-		-	-		-	-		-	-	-	67.7	55.9	-	1,015.5	839.0
B1b - HEA (HVAC Systems	Programmable Thermostat, Wood Pellets	E21B1b014	-	21	18		-	-		-	-		-	-		-	-	-	67.7	55.9	-	1,015.5	839.0
	Home Energy Assistance Subtotal					**-**	**181.8**	**160.2**	**-**	**2,571.0**	**2,253.4**	**-**	**47.2**	**40.6**	**-**	**12.7**	**11.4**	**-**	**1,809.0**	**1,496.1**	**-**	**39,022.8**	**32,230.0**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
A1a - ES Homes	Cooling, Electric, SF	E21A1a001	-	13	10		0.5	0.4		13.6	10.2		-	-		0.3	0.2	-	-	-	-	-	-
A1a - ES Homes	Heating, Electric, SF	E21A1a002	-	35	26		385.8	289.1		9,644.0	7,226.4		104.7	91.8		-	-	-	-	-	-	-	-
A1a - ES Homes	Heating, Propane, SF	E21A1a005	-	27	20		12.2	9.1		304.5	228.1		3.6	-		-	-	-	1,454.9	1,090.2	-	36,373.6	27,255.3
A1a - ES Homes	Hot Water, Electric, SF	E21A1a007	-	13	10		24.1	18.1		361.5	270.9		4.7	3.6		1.8	1.4	-	-	-	-	-	-
A1a - ES Homes	Hot Water, Propane, SF	E21A1a010	-	13	10		0.8	0.6		12.2	9.1		0.1	-		0.1	-	-	60.7	45.5	-	911.0	682.6
A1a - ES Homes	Cooling, Electric, MF	E21A1a012	-	13	10		1.9	1.4		47.6	35.7		-	-		1.1	0.8	-	-	-	-	-	-
A1a - ES Homes	Heating, Propane, MF	E21A1a016	-	27	20		8.1	6.1		202.2	151.5		2.4	-		-	-	-	990.3	742.0	-	24,757.4	18,551.1
A1a - ES Homes	Hot Water, Propane, MF	E21A1a021	-	13	10		-	-		-	-		-	-		-	-	-	81.4	61.0	-	1,221.3	915.1
A1a - ES Homes	Refrigerator	E21A1a025	-	66	50		2.9	2.2		35.2	26.4		0.3	0.3		0.4	0.3	-	-	-	-	-	-
A1a - ES Homes	Clothes Washer	E21A1a026	-	49	36		4.4	3.3		48.1	36.0		0.6	0.5		0.6	0.4	-	3.4	2.6	-	37.4	28.1
A1a - ES Homes	Clothes Dryer	E21A1a027	-	18	13		2.8	2.1		34.0	25.5		0.5	0.4		0.4	0.3	-	-	-	-	-	-
	ES Homes Subtotal					**-**	**443.5**	**332.3**	**-**	**10,702.9**	**8,019.8**	**-**	**116.9**	**96.4**	**-**	**4.6**	**3.4**	**-**	**2,590.8**	**1,941.3**	**-**	**63,300.7**	**47,432.2**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
A2a - HPwES (Weatherizat	Air Sealing, Cord Wood	E21A2a001	-	135	77		-	-		-	-		-	-		-	-	-	323.4	183.6	-	4,851.6	2,753.8
A2a - HPwES (Weatherizat	Air Sealing, Electric	E21A2a002	-	135	77		46.1	26.2		691.9	392.7		14.6	8.3		-	-	-	-	-	-	-	-
A2a - HPwES (Weatherizat	Air Sealing, Kerosene	E21A2a004	-	135	77		-	-		-	-		-	-		-	-	-	32.3	18.3	-	484.9	275.2
A2a - HPwES (Weatherizat	Air Sealing, Oil	E21A2a005	-	135	77		-	-		-	-		-	-		-	-	-	537.5	305.1	-	8,062.6	4,576.4
A2a - HPwES (Weatherizat	Air Sealing, Propane	E21A2a006	-	135	77		-	-		-	-		-	-		-	-	-	430.7	244.5	-	6,460.4	3,666.9
A2a - HPwES (Weatherizat	Insulation, Cord Wood	E21A2a022	-	135	77		-	-		-	-		-	-		-	-	-	1,428.6	810.9	-	35,715.4	20,272.2
A2a - HPwES (Weatherizat	Insulation, Electric	E21A2a023	-	135	77		218.1	123.8		5,451.9	3,094.5		69.2	39.3		-	-	-	-	-	-	-	-
A2a - HPwES (Weatherizat	Insulation, Kerosene	E21A2a025	-	135	77		-	-		-	-		-	-		-	-	-	182.2	103.4	-	4,556.1	2,586.1
A2a - HPwES (Weatherizat	Insulation, Oil	E21A2a026	-	135	77		-	-		-	-		-	-		-	-	-	2,676.0	1,518.9	-	66,899.5	37,972.4
A2a - HPwES (Weatherizat	Insulation, Propane	E21A2a027	-	135	77		-	-		-	-		-	-		-	-	-	2,046.6	1,161.7	-	51,165.1	29,041.6
A2a - HPwES (Weatherizat	LED Bulb, General Service Lamps	E21A2a044	-	54	31		15.6	8.9		31.2	17.7		3.4	1.9		2.2	1.2	-	(36.9)	(21.0)	-	(73.8)	(41.9)
A2a - HPwES (Weatherizat	Visual Audit Oil Savings	E21A2a050	-	147	147		-	-		-	-		-	-		-	-	-	1,225.9	1,225.9	-	16,856.5	16,856.5
A2a - HPwES (Weatherizat	Visual Audit Propane Savings	E21A2a051	-	147	147		-	-		-	-		-	-		-	-	-	366.7	366.7	-	5,041.9	5,041.9
A2a - HPwES (Weatherizat	Visual Audit Electric Savings	E21A2a052	-	147	147		53.6	53.6		268.0	268.0		17.0	17.0		-	-	-	-	-	-	-	-
A2b - HPwES (HVAC Syst	Programmable Thermostat, Electric	E21A2b009	-	20	11		4.7	2.7		70.2	39.9		7.5	4.2		-	-	-	-	-	-	-	-
A2b - HPwES (HVAC Syst	Programmable Thermostat, Kerosene	E21A2b011	-	20	11		-	-		-	-		-	-		-	-	-	77.5	44.0	-	1,163.0	660.1
A2b - HPwES (HVAC Syst	Programmable Thermostat, Oil	E21A2b012	-	20	11		-	-		-	-		-	-		-	-	-	77.5	44.0	-	1,163.0	660.1
A2b - HPwES (HVAC Syst	Programmable Thermostat, Propane	E21A2b013	-	20	11		-	-		-	-		-	-		-	-	-	77.5	44.0	-	1,163.0	660.1
A2b - HPwES (HVAC Syst	Programmable Thermostat, Wood Pellets	E21A2b014	-	20	11		-	-		-	-		-	-		-	-	-	77.5	44.0	-	1,163.0	660.1
A2b - HPwES (HVAC Syst	Ancillary Savings – Boiler Circulator Pump	E21A2b022	-	69	39		5.6	3.2		106.7	60.6		1.7	0.9		-	-	-	-	-	-	-	-
A2b - HPwES (HVAC Syst	Ancillary Savings – Furnace	E21A2b023	-	37	21		0.3	0.2		5.7	3.2		0.1	0.1		-	-	-	-	-	-	-	-
A2b - HPwES (HVAC Syst	Ancillary Savings – Central AC	E21A2b024	-	49	28		-	-		-	-		-	-		-	-	-	-	-	-	-	-
	Home Performance with Energy Star Subtotal					**-**	**344.0**	**218.4**	**-**	**6,625.5**	**3,876.6**	**-**	**113.5**	**71.8**	**-**	**2.2**	**1.2**	**-**	**9,523.2**	**6,094.1**	**-**	**204,672.1**	**125,641.5**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
A3a - ES Lighting	LED Bulb, General Service Lamps (Hard to Reach)	E21A3a005	-	74,274	37,434		843.2	326.1		2,529.7	652.3		182.0	70.4		117.4	45.4	-	(1,915.8)	(741.0)	-	(5,747.4)	(1,482.0)
A3a - ES Lighting	LED Bulb, Other Specialty (Hard to Reach)	E21A3a007	-	18,568	9,358		190.4	73.7		571.3	147.3		41.1	15.9		26.5	10.3	-	(432.7)	(167.4)	-	(1,298.1)	(334.7)
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (cooling)	E21A3b005	-	800	800		92.4	92.4		1,662.6	1,662.6		-	-		42.7	42.7	-	-	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (heating)	E21A3b006	-	800	800		305.8	305.8		5,504.7	5,504.7		139.0	139.0		-	-	-	-	-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Downstream	E21A3b007	-	197	197		189.7	189.7		2,466.7	2,466.7		31.1	31.1		17.2	17.2	-	424.3	424.3	-	5,516.1	5,516.1
A3b - ES Appliances	ES Clothes Dryers	E21A3b010	-	778	499		124.7	80.1		1,496.6	961.0		21.3	13.6		16.4	10.5	-	-	-	-	-	-
A3b - ES Appliances	Dryer Heat Pump	E21A3b011	-	51	33		21.6	13.9		259.2	166.5		3.7	2.4		2.8	1.8	-	-	-	-	-	-
A3b - ES Appliances	Dryer Hybrid	E21A3b012	-	26	17		5.6	3.6		67.1	43.1		1.0	0.6		0.7	0.5	-	-	-	-	-	-
A3b - ES Appliances	ECM Motor for FWH Circulating Pump	E21A3b013	-	3	2		0.2	0.1		3.5	2.2		0.1	0.1		-	-	-	-	-	-	-	-
A3b - ES Appliances	Room Air Conditioner	E21A3b016	-	519	333		17.1	11.0		154.1	98.9		-	-		8.9	5.7	-	-	-	-	-	-
A3b - ES Appliances	ES Clothes Washers	E21A3b017	-	778	499		69.9	44.9		768.9	493.7		9.8	6.3		9.3	6.0	-	54.4	34.9	-	598.7	384.4
A3b - ES Appliances	Washer Tier CEE Tier 2+	E21A3b018	-	622	400		86.5	55.5		951.1	610.7		12.1	7.8		11.5	7.4	-	298.8	191.9	-	3,286.7	2,110.4
A3b - ES Appliances	ES Dehumidifier	E21A3b019	-	622	400		51.2	32.9		614.8	394.7		2.1	1.3		9.8	6.3	-	-	-	-	-	-
A3b - ES Appliances	Refrigerator	E21A3b022	-	674	433		29.8	19.1		357.4	229.5		3.4	2.2		4.2	2.7	-	-	-	-	-	-
A3b - ES Appliances	Refrigerator CEE Tier 2+	E21A3b023	-	259	166		24.9	16.0		299.4	192.2		2.9	1.8		3.5	2.2	-	-	-	-	-	-
A3b - ES Appliances	ES Pool Pumps (Variable Speed)	E21A3b024	-	78	50		99.5	63.9		995.4	639.2		-	-		57.5	36.9	-	-	-	-	-	-
A3b - ES Appliances	Room Air Purifier	E21A3b025	-	259	166		98.0	62.9		882.3	566.5		11.2	7.2		11.2	7.2	-	-	-	-	-	-
A3b - ES Appliances	Primary Refrigerator Recycling	E21A3b027	-	104	67		106.5	68.4		532.7	342.1		12.2	7.8		14.9	9.6	-	-	-	-	-	-
A3b - ES Appliances	Secondary Refrigerator Recycling	E21A3b028	-	259	166		265.8	170.7		1,328.9	853.3		24.9	16.0		41.5	26.7	-	-	-	-	-	-
A3b - ES Appliances	Room Air Conditioner Recycling	E21A3b030	-	8	5		0.9	0.6		2.7	1.7		-	-		0.7	0.4	-	-	-	-	-	-
	ES Products Subtotal					**-**	**2,624.0**	**1,631.4**	**-**	**21,449.2**	**16,029.1**	**-**	**497.8**	**323.6**	**-**	**396.7**	**239.4**	**-**	**(1,570.9)**	**(257.2)**	**-**	**2,356.2**	**6,194.3**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
C1a - LCI Retrofit	Custom Large Other Retro	E21C1a008	-	8	5		1,025.4	710.8		13,329.7	9,240.3		361.7	250.7		-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C1a011	-	1	1		60.8	39.7		607.5	397.5		12.2	8.0		-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C1a013	-	11	8		863.5	564.9		8,634.7	5,649.4		67.2	44.0		87.1	57.0	-	(597.3)	(390.8)	-	(5,972.5)	(3,907.7)
C1a - LCI Retrofit	Lighting Occupancy Sensors	E21C1a014	-	0	0		1.0	0.7		9.2	6.0		0.0	0.0		0.0	0.0	-	(2.8)	(1.8)	-	(25.0)	(16.3)
C1a - LCI Retrofit	Door Heater Controls	E21C1a019	-	4	3		281.1	194.9		2,810.9	1,948.5		32.1	22.3		16.1	11.1	-	-	-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive	E21C1a043	-	1	1		82.7	57.3		1,240.8	860.1		-	-		-	-	-	-	-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - IPLV	E21C1b053	-	1	1		56.7	56.7		1,303.0	1,303.0		1.6	1.6		12.8	12.8	-	-	-	-	-	-
C1c - LCI Midstream	Midstream Unitary Air Conditioners	E21C1c007	-	0	0		1.2	0.8		14.3	9.9		-	-		0.1	0.1	-	-	-	-	-	-
C1c - LCI Midstream	Midstream VRF	E21C1c008	-	1	1		59.0	59.0		707.8	707.8		-	-		5.2	5.2	-	-	-	-	-	-
	Large Business Energy Solutions Subtotal					**-**	**2,431.2**	**1,684.8**	**-**	**28,657.8**	**20,122.6**	**-**	**474.8**	**326.5**	**-**	**121.4**	**86.3**	**-**	**(600.0)**	**(392.6)**	**-**	**(5,997.5)**	**(3,924.0)**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
C2a - SCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C2a011	-	29	22		365.1	265.4		3,651.5	2,653.8		71.1	51.7		-	-	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C2a013	-	79	61		997.4	724.9		9,974.0	7,248.8		72.8	52.9		94.3	68.5	-	(646.5)	(469.9)	-	(6,465.3)	(4,698.8)
C2a - SCI Retrofit	Door Heater Controls	E21C2a019	-	6	4		92.6	71.3		926.5	713.4		9.8	7.5		4.9	3.8	-	-	-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive	E21C2a043	-	2	1		48.1	37.0		721.3	555.4		-	-		-	-	-	-	-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C2b011	-	8	6		82.8	60.2		1,242.1	902.7		16.1	11.7		-	-	-	-	-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/o Controls	E21C2b013	-	10	7		105.6	76.7		1,583.3	1,150.7		7.7	5.6		10.0	7.3	-	(16.1)	(11.7)	-	(241.0)	(175.2)
C2b - SCI New Equipment	Unitary Air Conditioner	E21C2b049	-	6	4		17.8	13.7		213.8	164.6		-	-		-	-	-	-	-	-	-	-
	Small Business Energy Solutions Subtotal					**-**	**1,709.5**	**1,249.2**	**-**	**18,312.4**	**13,389.5**	**-**	**177.5**	**129.4**	**-**	**109.2**	**79.6**	**-**	**(662.6)**	**(481.6)**	**-**	**(6,706.3)**	**(4,874.0)**

			Quantity			Net Annual MWh Savings			Net Lifetime MWh Savings			Annual Net Winter kW			Annual Net Summer kW			Total Net Annual MMBTU			Total Net Lifetime MMBTU		
Subprogram	Measure	Measure ID	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
C3a - Muni Retrofit	Lighting Fixture - Interior w/o Controls	E21C3a013	-	16	13		302.1	225.9		3,021.5	2,259.2		22.1	16.5		28.6	21.4	-	(195.9)	(146.4)	-	(1,958.6)	(1,464.4)
	Municipal Energy Solutions Subtotal					**-**	**302.1**	**225.9**	**-**	**3,021.5**	**2,259.2**	**-**	**22.1**	**16.5**	**-**	**28.6**	**21.4**	**-**	**(195.9)**	**(146.4)**	**-**	**(1,958.6)**	**(1,464.4)**

New Hampshire Electric Cooperative, Inc.
2022-2023 System Benefits Charge ("SBC") Calculation
($ in 000's)

Year	EE Total Budget	RGGI Revenues	FCM Revenues	Carryforward with Interest	SBC Requirement	Forecasted Distribution (MWH)	2022 Jan-Feb SBC Rate EE Portion (cents/kWh)	2022 Mar-Dec SBC Rate EE Portion (cents/kWh)	2023 Jan-Dec SBC Rate EE Portion (cents/kWh)	SBC Rate EAP Portion (cents/kWh)	2022 Jan-Feb Total SBC Rate (cents/kWh)	2022 Mar-Dec Total SBC Rate (cents/kWh)	2023 Jan-Dec Total SBC Rate (cents/kWh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
2022	$ 5,713	$ 207	$ 100	$ 1,532	$ 3,873	786,599	$ 0.373	$ 0.528		$ 0.150	$ 0.523	$ 0.678	
2023	$ 4,507	$ 207	$ 100	$ -	$ 4,199	777,382			$ 0.543	$ 0.150			$ 0.693

Col. A: Effective year
Col. B: Budget Projections
Col. C: Budget Projections
Col. D: Budget Projections
Col. E: Budget Projections
Col. F: Col. B - Col. C - Col. D - Col. E
Col. G: Company Forecast
Col. H: (Col. H / Col. I) x 100
Col. K: EAP Portion of SBC Rate
Col. M: Col. J + Col. K

New Hampshire Electric Cooperative, Inc.
Energy Efficiency Expense & SBC Revenue Reconcilliation
January 1, 2022 to December 31, 2022
($ in 000's)

Line	Description	Carryover 12/31/21	Forecast Jan 2022	Forecast Feb 2022	Forecast Mar 2022	Forecast Apr 2022	Forecast May 2022	Forecast June 2022	Forecast Jul 2022	Forecast Aug 2022	Forecast Sep 2022	Forecast Oct 2022	Forecast Nov 2022	Forecast Dec 2022	2022 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	kWh Sales	1,532	322	293	355	343	270	280	356	350	361	285	283	376	3,873
2	RGGI Revenues		17	17	17	17	17	17	17	17	17	17	17	17	207
3	FCM Revenues		8	8	8	8	8	8	8	8	8	8	8	8	100
4	**Total Revenues**		**348**	**319**	**381**	**368**	**295**	**306**	**382**	**375**	**387**	**310**	**309**	**401**	**4,180**
5	Program Expenses		476	476	476	476	476	476	476	476	476	476	476	476	5,713
6	**Total Program Expenses**		**476**	**476**	**476**	**476**	**476**	**476**	**476**	**476**	**476**	**476**	**476**	**476**	**5,713**
7	Current Month Over/(Under) Recovery		(128)	(157)	(95)	(108)	(181)	(170)	(94)	(101)	(90)	(166)	(167)	(75)	
8	Cummulative Over/(Under) Recovery	1,532	1,404	1,246	1,151	1,043	863	692	598	497	407	242	75	0	
11	Interest @ Prime Rate		0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
12	**Interest**		**4**	**4**	**3**	**3**	**3**	**2**	**2**	**1**	**1**	**1**	**0**	**0**	**24**
13	**Monthly Sales (MWh)**		86,829	79,055	67,616	65,290	51,453	53,394	67,784	66,601	68,721	54,318	54,018	71,520	786,599
14	**EE SBC Rate**		0.373	0.373	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	0.528	

Line 1: (Line 14 x Line 15) / 100
Line 2: Page 1, Col. C
Line 3: Page 1, Col. D
Line 4: Sum of Lines 1 through Lines 3
Line 5: Page 1, Col. B
Line 6: Sum of Line 6
Line 7: Line 5 - Line 6
Line 8: Prior month Line 8 + Current month Line 8
Line 11: Prime Rate / 12
Line 12: (Prior Month Line 8 + Current Month Line 8) / 2 x Line 11
Line 13: Company Forecast
Line 14: Page 1, Col. J/K

New Hampshire Electric Cooperative, Inc.
Energy Efficiency Expense & SBC Revenue Reconcilliation
January 1, 2022 to December 31, 2023
($ in 000's)

Line	Description	Carryover 12/31/21	Forecast Jan 2022	Forecast Feb 2022	Forecast Mar 2022	Forecast Apr 2022	Forecast May 2022	Forecast June 2022	Forecast Jul 2022	Forecast Aug 2022	Forecast Sep 2022	Forecast Oct 2022	Forecast Nov 2022	Forecast Dec 2022	2022 Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	kWh Sales	-	464	422	361	349	274	285	362	356	367	290	288	382	4,199
2	RGGI Revenues		17	17	17	17	17	17	17	17	17	17	17	17	207
3	FCM Revenues		8	8	8	8	8	8	8	8	8	8	8	8	100
4	**Total Revenues**		**490**	**448**	**387**	**374**	**300**	**310**	**388**	**381**	**393**	**315**	**314**	**408**	**4,507**
5	Program Expenses		376	376	376	376	376	376	376	376	376	376	376	376	4,507
6	**Total Program Expenses**		**376**	**376**	**376**	**376**	**376**	**376**	**376**	**376**	**376**	**376**	**376**	**376**	**4,507**
7	Current Month Over/(Under) Recovery		114	72	11	(1)	(76)	(65)	12	6	17	(60)	(62)	32	
8	Cummulative Over/(Under) Recovery	-	114	187	198	196	121	55	67	73	90	30	(32)	(0)	
11	Interest @ Prime Rate		0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	
12	**Interest**		**0**	**0**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**3**
13	**Monthly Sales (MWh)**		85,812	78,129	66,824	64,525	50,851	52,768	66,990	65,820	67,916	53,682	53,385	70,682	777,382
14	**EE SBC Rate**		0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.543	

Line 1: (Line 14 x Line 15) / 100
Line 2: Page 1, Col. C
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Line 11: Prime Rate / 12
Line 12: (Prior Month Line 8 + Current Month Line 8) / 2 x Line 11
Line 13: Company Forecast
Line 14: Page 1, Col. J/K

Bill Impacts of Changes in System Benefits Charge - New Hampshire Electric Cooperative, Inc.

	2021	Jan-Feb 2022	Mar-Dec 2022	2023
System Benefits Charge ($/kWh)	$ 0.00678	$ 0.00523	0.00678	0.00693
Bill per month, including NHEC default energy service				
Residential Rate B (625 kWh/month)	$ 124.33	$ 123.36	$ 124.33	$ 124.42
Commercial B3, three-phase service (<50 kW, 10,000 kWh/month)	$ 1,766.24	$ 1,750.74	$ 1,766.24	$ 1,767.74
Change from previous rate level - $ per month				
Residential Rate B (625 kWh/month)		$ (0.97)	$ 0.97	$ 0.09
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		$ (15.50)	$ 15.50	$ 1.50
Change from previous rate level - %				
Residential Rate B (625 kWh/month)		-0.8%	0.8%	0.1%
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		-0.9%	0.9%	0.1%

Program Cost-Effectiveness - 2022 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.73	1.73	2,077.5	2,077.5	1,204.3	-	142.4	2,096.2	21.9	22.7	112	2,124.8	43,427.1
A1 - Energy Star Homes	2.82	3.39	2,035.8	1,642.6	484.4	237.9	124.4	3,000.0	37.1	1.9	158	1,564.0	38,400.0
A2 - Home Performance with Energy Star	2.32	2.08	1,751.9	1,415.4	681.4	73.0	156.5	3,145.6	38.8	13.6	66	1,808.0	36,241.9
A3 - Energy Star Products	1.69	2.09	1,337.6	1,095.0	524.6	268.0	800.1	8,586.0	165.0	105.5	5,499	482.3	10,211.5
A4 - Residential Behavior	2.20	1.76	385.8	308.6	175.0	-	3,100.0	3,100.0	669.2	431.7	-	-	-
A5 - Residential Active Demand Response	-	-	-	-	67.0	-	-	-	-	-		-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	10.9	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.02**	**2.06**	**7,588.6**	**6,539.2**	**3,180.9**	**578.8**	**4,323.4**	**19,927.7**	**932.0**	**575.3**	**5,835**	**5,979.1**	**128,280.5**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.67	2.05	2,765.1	2,517.3	1,225.3	425.6	2,266.5	28,144.5	427.1	353.8	146	(354.1)	(3,653.8)
C2 - Small Business Energy Solutions	1.33	1.74	2,270.0	2,063.3	1,182.6	526.7	2,160.3	26,503.5	243.6	208.1	321	(368.7)	(3,855.9)
C3 - Municipal Energy Solutions	1.12	1.18	281.6	256.0	217.2	33.9	308.5	3,457.4	29.4	28.7	9	(33.9)	(305.0)
C5 - C&I Active Demand Response	-	-	-	-	175.4	-	-	-	-	-		-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	18.4	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	29.1	-	-	-	-	-	-	-	-
C6d - C&I Customer Partnerships	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.39**	**1.70**	**5,316.7**	**4,836.7**	**2,848.1**	**986.2**	**4,735.3**	**58,105.4**	**700.1**	**590.5**	**476**	**(756.7)**	**(7,814.7)**
Total	**1.70**	**1.89**	**12,905.3**	**11,375.9**	**6,029.0**	**1,565.0**	**9,058.7**	**78,033.1**	**1,632.1**	**1,165.9**	**6,310.7**	**5,222.4**	**120,465.8**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual kWh Savings	9,058,743	85.5%	**kWh > 65%**	**Lifetime** kWh Savings	78,033,127	68.8%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	1,530,547	14.5%		**Lifetime** MMBTU Savings (in kWh)	35,305,051	31.2%	
	10,589,290	100.0%			**113,338,178**	100.0%	

Annual Net Savings as a % of 2019 Sales	0.78%

Spending per Customer	Low-Income	$ 181.37
	Residential	$ 33.08
	C&I	$ 260.74

Present Value Benefits - 2022 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environmental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 2,078**	$ 15	$ -	$ 28	$ 29	$ -	$ 41	$ 45	$ 18	$ 17	$ 8	**$ 200**	$ 1,214	$ 15	**$ 1,429**	$ 81	$ 567	**$ 649**	**$ 84**
A1 - Energy Star Homes	**$ 1,643**	$ 2	$ -	$ 3	$ 3	$ -	$ 80	$ 101	$ 2	$ 2	$ 9	**$ 202**	$ 1,371	$ -	**$ 1,573**	$ 70	$ 393	**$ 463**	**$ 90**
A2 - Home Performance with Energy Star	**$ 1,415**	$ 12	$ -	$ 21	$ 22	$ -	$ 72	$ 90	$ 14	$ 12	$ 10	**$ 254**	$ 1,092	$ 4	**$ 1,350**	$ 65	$ 336	**$ 402**	**$ 106**
A3 - Energy Star Products	**$ 1,095**	$ 43	$ -	$ 84	$ 87	$ -	$ 188	$ 205	$ 62	$ 54	$ 40	**$ 762**	$ 208	$ 110	**$ 1,080**	$ 15	$ 243	**$ 257**	**$ 377**
Sub-Total Residential	**$ 6,539**	**$ 91**	**$ -**	**$ 173**	**$ 179**	**$ -**	**$ 461**	**$ 506**	**$ 127**	**$ 106**	**$ 85**	**$ 1,727**	**$ 3,885**	**$ 129**	**$ 5,741**	**$ 231**	**$ 1,617**	**$ 1,848**	**$ 856**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 2,517**	$ 176	$ -	$ 339	$ 350	$ -	$ 453	$ 383	$ 401	$ 307	$ 129	**$ 2,538**	$ (60)	$ 44	**$ 2,522**	$ (5)	$ 248	**$ 243**	**$ 1,269**
C2 - Small Business Energy Solutions	**$ 2,063**	$ 111	$ -	$ 211	$ 218	$ -	$ 483	$ 344	$ 389	$ 252	$ 123	**$ 2,130**	$ (64)	$ 2	**$ 2,068**	$ (5)	$ 207	**$ 202**	**$ 1,189**
C3 - Municipal Energy Solutions	**$ 256**	$ 14	$ -	$ 26	$ 27	$ -	$ 33	$ 32	$ 61	$ 54	$ 16	**$ 261**	$ (5)	$ -	**$ 256**	$ (0)	$ 26	**$ 25**	**$ 168**
Sub-Total Commercial & Industrial	**$ 4,837**	**$ 301**	**$ -**	**$ 576**	**$ 595**	**$ -**	**$ 969**	**$ 758**	**$ 850**	**$ 613**	**$ 267**	**$ 4,930**	**$ (129)**	**$ 46**	**$ 4,847**	**$ (10)**	**$ 480**	**$ 470**	**$ 2,626**
Total	**$ 11,376**	**$ 392**	**$ -**	**$ 750**	**$ 774**	**$ -**	**$ 1,430**	**$ 1,264**	**$ 977**	**$ 719**	**$ 352**	**$ 6,656**	**$ 3,755**	**$ 175**	**$ 10,587**	**$ 221**	**$ 2,097**	**$ 2,318**	**$ 3,482**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

	Portfolio Planned Versus Actual Performance - 2022										
	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime kWh Savings	78,033,127	*58,524,845*		-	1.925%	-	$ 116,057	*$ 145,072*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	9,058,743	*6,794,058*		-	0.550%	-	$ 33,159	*$ 41,449*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	1,166	*758*		-	0.660%	-	$ 39,791	*$ 49,739*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	1,632	*1,061*		-	0.440%	-	$ 26,527	*$ 33,159*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 10,587,337			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 6,028,950			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 4,558,387	*$ 3,418,790*	$ -	-	1.925%	-	$ 116,057	*$ 145,072*	$ -	Line 5 minus line 6
9	Total					5.500%	-	$ 331,592	*$ 414,490*	$ -	

		Granite State Test		
		Planned	Actual	Source
10	Total Benefits	$ 11,375,870		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 331,592	$ -	from row 9 above
12	Total Utility Costs	$ 6,028,950	$ -	from row 7 above
13	**Portfolio GST BCR**	**1.79**	**-**	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

Program Cost-Effectiveness - 2023 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.92	1.92	2,433.7	2,433.7	1,269.7	-	144.4	2,159.0	21.7	24.2	128	2,425.5	49,628.6
A1 - Energy Star Homes	3.03	3.67	2,202.3	1,778.2	484.9	241.6	118.4	2,835.0	30.1	2.0	166	1,690.0	41,550.0
A2 - Home Performance with Energy Star	2.46	2.21	1,859.5	1,503.2	681.6	72.9	157.3	3,163.6	38.8	14.0	68	1,869.8	37,547.3
A3 - Energy Star Products	1.70	2.10	1,343.3	1,103.4	524.6	263.4	788.3	8,024.0	150.5	105.6	5,856	558.2	10,799.9
A5 - Residential Active Demand Response	-	-	-	-	67.1	-	-	-	-	-		-	-
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	10.9	-	-	-	-	-	-	-	-
Sub-Total Residential	**2.15**	**2.20**	**8,219.4**	**7,122.9**	**3,244.6**	**577.8**	**4,324.7**	**19,298.0**	**913.8**	**579.7**	**6,218**	**6,543.4**	**139,525.8**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.30	1.48	2,197.9	2,001.8	1,350.7	338.2	2,419.2	29,284.3	182.8	129.1	128	(330.0)	(2,890.4)
C2 - Small Business Energy Solutions	1.31	1.65	2,360.1	2,145.1	1,303.9	497.1	2,354.4	28,951.3	216.7	166.9	327	(408.3)	(4,236.2)
C3 - Municipal Energy Solutions	1.10	1.15	265.8	241.6	209.3	31.3	324.0	3,614.8	30.5	8.5	7	(32.0)	(287.8)
C5 - C&I Active Demand Response	-	-	-	-	193.0	-	-	-	-	-		-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	20.3	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	26.9	-	-	-	-	-	-	-	-
C6d - C&I Customer Partnerships	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.21**	**1.41**	**4,823.8**	**4,388.5**	**3,104.1**	**866.6**	**5,097.5**	**61,850.4**	**430.0**	**304.5**	**462**	**(770.3)**	**(7,414.4)**
C6e - Smart Start	-	-	-	-	-	-	-	-	-	-		-	-
Total	**1.67**	**1.81**	**13,043.1**	**11,511.5**	**6,348.7**	**1,444.5**	**9,422.3**	**81,148.4**	**1,343.8**	**884.2**	**6,680**	**5,773.2**	**132,111.3**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2023.

Annual kWh Savings	9,422,287	84.8%	**kWh > 65%**	**Lifetime** kWh Savings	81,148,382	67.7%	**kWh > 65%**
Annual MMBTU Savings (in kWh)	1,691,950	15.2%		**Lifetime** MMBTU Savings (in kWh)	38,718,005	32.3%	
	11,114,237	100.0%			**119,866,387**	100.0%	

Annual Net Savings as a % of 2019 Sales	0.81%

Spending per Customer	Low-Income	$	191.23
	Residential	$	33.05
	C&I	$	284.18

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environ-mental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 2,434**	$ 17	$ -	$ 31	$ 32	$ -	$ 42	$ 46	$ 20	$ 18	$ 9	**$ 215**	$ 1,442	$ 15	**$ 1,672**	$ 101	$ 661	**$ 761**	**$ 82**
A1 - Energy Star Homes	**$ 1,778**	$ 2	$ -	$ 3	$ 3	$ -	$ 65	$ 82	$ 2	$ 2	$ 8	**$ 168**	$ 1,529	$ -	**$ 1,696**	$ 82	$ 424	**$ 506**	**$ 70**
A2 - Home Performance with Energy Star	**$ 1,503**	$ 13	$ -	$ 23	$ 23	$ -	$ 74	$ 92	$ 15	$ 12	$ 11	**$ 263**	$ 1,162	$ 4	**$ 1,430**	$ 73	$ 356	**$ 430**	**$ 102**
A3 - Energy Star Products	**$ 1,103**	$ 42	$ -	$ 82	$ 85	$ -	$ 177	$ 191	$ 61	$ 54	$ 39	**$ 732**	$ 228	$ 127	**$ 1,086**	$ 17	$ 240	**$ 257**	**$ 344**
Sub-Total Residential	**$ 7,123**	**$ 85**	**$ -**	**$ 177**	**$ 182**	**$ -**	**$ 437**	**$ 480**	**$ 128**	**$ 109**	**$ 84**	**$ 1,682**	**$ 4,361**	**$ 146**	**$ 6,189**	**$ 273**	**$ 1,757**	**$ 2,030**	**$ 814**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 2,002**	$ 56	$ -	$ 110	$ 114	$ -	$ 544	$ 356	$ 395	$ 301	$ 133	**$ 2,010**	$ (49)	$ 45	**$ 2,006**	$ (4)	$ 196	**$ 192**	**$ 1,219**
C2 - Small Business Energy Solutions	**$ 2,145**	$ 78	$ -	$ 150	$ 155	$ -	$ 753	$ 382	$ 332	$ 231	$ 142	**$ 2,223**	$ (72)	$ 1	**$ 2,151**	$ (6)	$ 215	**$ 209**	**$ 1,235**
C3 - Municipal Energy Solutions	**$ 242**	$ 3	$ -	$ 6	$ 7	$ -	$ 59	$ 82	$ 32	$ 39	$ 19	**$ 247**	$ (5)	$ -	**$ 242**	$ (0)	$ 24	**$ 24**	**$ 167**
Sub-Total Commercial & Industrial	**$ 4,389**	**$ 138**	**$ -**	**$ 266**	**$ 275**	**$ -**	**$ 1,357**	**$ 819**	**$ 759**	**$ 570**	**$ 294**	**$ 4,479**	**$ (127)**	**$ 46**	**$ 4,399**	**$ (10)**	**$ 435**	**$ 425**	**$ 2,621**
Total	**$ 11,511**	**$ 223**	**$ -**	**$ 443**	**$ 457**	**$ -**	**$ 1,794**	**$ 1,299**	**$ 887**	**$ 680**	**$ 378**	**$ 6,161**	**$ 4,234**	**$ 193**	**$ 10,588**	**$ 263**	**$ 2,192**	**$ 2,455**	**$ 3,436**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

	Portfolio Planned Versus Actual Performance - 2023											
	Portfolio	**Planned**	**Threshold**	**Actual**	**% of Plan**	**Design Coefficient**	**Actual Coefficient**	**Planned PI**	***125% of Planned PI***	**Actual PI**	**Source**
1	Lifetime kWh Savings	81,148,382	*60,861,287*		-	1.925%	-	$ 122,213	*$ 152,766*	$ -	Planned and Actual from Cost Eff Tab
2	Annual kWh Savings	9,422,287	*7,066,715*		-	0.550%	-	$ 34,918	*$ 43,648*	$ -	Planned and Actual from Cost Eff Tab
3	Summer Peak Demand kW	884	*575*		-	0.660%	-	$ 41,902	*$ 52,377*	$ -	Planned and Actual from Cost Eff Tab
4	Winter Peak Demand kW	1,344	*873*		-	0.440%	-	$ 27,934	*$ 34,918*	$ -	Planned and Actual from Cost Eff Tab
5	Active Demand kW				-	0.000%	-	$ -	*$ -*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total Resource Benefits	$ 10,587,737			-						Planned and Actual from Benefits Tab
7	Total Utility Costs[1,2]	$ 6,348,730			-						Planned and Actual from Cost Eff Tab
8	Net Benefits	$ 4,239,008	*$ 3,179,256*	$ -	-	1.925%	-	$ 122,213	*$ 152,766*	$ -	Line 5 minus line 6
9	Total					5.500%	-	$ 349,180	*$ 436,475*	$ -	

		Granite State Test		
		Planned	**Actual**	**Source**
10	Total Benefits	$ 11,511,468		Planned and Actual from Cost Eff Tab
11	Performance Incentive	$ 349,180	$ -	from row 9 above
12	Total Utility Costs	$ 6,348,730	$ -	from row 7 above
13	**Portfolio GST BCR**	**1.72**	-	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $360,528.49.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

ADR Program Cost-Effectiveness

2022	Benefit/Cost Ratios		Benefits ($000)								
	Granite State Test	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Utility Costs ($000 - 2022$)[1]	Customer Costs ($000 - 2022$)[1]	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served
Residential Programs											
A5 - Residential Active Demand Response	0.00	0.00	-	-	64.9	-	-	-	-	-	-
Sub-Total Residential	**0.00**	**0.00**	**-**	**-**	**64.9**	**-**	**-**	**-**	**-**	**-**	**-**
Commercial, Industrial & Municipal											
C5 - C&I Active Demand Response	0.00	0.00	-	-	169.9	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**0.00**	**0.00**	**-**	**-**	**169.9**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**0.00**	**0.00**	**-**	**-**	**234.8**	**-**	**-**	**-**	**-**	**-**	**-**

(1) Utility and Customer Costs in 2022 Dollars.

2023	Benefit/Cost Ratios		Benefits ($000)								
	Granite State Test	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Utility Costs ($000 - 2022$)[1]	Customer Costs ($000 - 2022$)[1]	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served
Residential Programs											
A5 - Residential Active Demand Response	0.00	0.00	-	-	65.0	-	-	-	-	-	-
Sub-Total Residential	**0.00**	**0.00**	**-**	**-**	**65.0**	**-**	**-**	**-**	**-**	**-**	**-**
Commercial, Industrial & Municipal											
C5 - C&I Active Demand Response	0.00	0.00	-	-	187.0	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**0.00**	**0.00**	**-**	**-**	**187.0**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**0.00**	**0.00**	**-**	**-**	**252.0**	**-**	**-**	**-**	**-**	**-**	**-**

(1) Utility and Customer Costs in 2022 Dollars.

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kW		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Air Sealing, Cord Wood	E21B1a001	-	-									-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Electric	E21B1a002	8	8	7.3	7.3	109.2	109.2	2.3	2.3	-	-	-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Gas	E21B1a003	-	-									-	-	-	-
B1a - HEA (Weatherization	Air Sealing, Kerosene	E21B1a004	19	22	1.7	2.0	25.9	30.0	-	-	1.0	1.1	138.3	160.2	2,074.8	2,402.4
B1a - HEA (Weatherization	Air Sealing, Oil	E21B1a005	40	45	3.6	4.1	54.6	61.4	-	-	2.0	2.3	364.0	409.5	5,460.0	6,142.5
B1a - HEA (Weatherization	Air Sealing, Propane	E21B1a006	25	30	2.3	2.7	34.1	41.0	-	-	1.3	1.5	227.5	273.0	3,412.5	4,095.0
B1a - HEA (Weatherization	Air Sealing, Wood Pellets	E21B1a007	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Cord Wood	E21B1a084	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Electric	E21B1a085	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Gas	E21B1a086	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Kerosene	E21B1a087	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Oil	E21B1a088	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Propane	E21B1a089	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing, Wood Pellets	E21B1a090	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Electric	E21B1a009	50	50	2.1	2.1	14.9	14.9	0.4	0.4	0.2	0.2	-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Gas	E21B1a010	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Kerosene	E21B1a011	-	-									-	-	-	-
B1a - HEA (Weatherization	Faucet Aerator, Oil	E21B1a012	80	80	-	-	-	-	-	-	-	-	11.4	11.4	79.5	79.5
B1a - HEA (Weatherization	Faucet Aerator, Propane	E21B1a013	40	40	-	-	-	-	-	-	-	-	5.7	5.7	39.7	39.7
B1a - HEA (Weatherization	Tank Wrap, Electric	E21B1a091	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Gas	E21B1a092	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Kerosene	E21B1a093	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Oil	E21B1a094	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap, Propane	E21B1a095	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Electric	E21B1a016	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Gas	E21B1a017	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Kerosene	E21B1a018	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Oil	E21B1a019	-	-									-	-	-	-
B1a - HEA (Weatherization	Hand Held Showerhead, Propane	E21B1a020	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Cord Wood	E21B1a022	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Electric	E21B1a023	8	8	18.2	18.2	455.0	455.0	5.8	5.8	-	-	-	-	-	-
B1a - HEA (Weatherization	Insulation, Gas	E21B1a024	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulation, Kerosene	E21B1a025	19	22	2.6	3.0	64.8	75.1	-	-	1.4	1.7	207.5	240.2	5,187.0	6,006.0
B1a - HEA (Weatherization	Insulation, Oil	E21B1a026	40	45	5.5	6.1	136.5	153.6	-	-	3.0	3.4	546.0	614.3	13,650.0	15,356.3
B1a - HEA (Weatherization	Insulation, Propane	E21B1a027	25	30	3.4	4.1	85.3	102.4	-	-	1.9	2.3	341.3	409.5	8,531.3	10,237.5
B1a - HEA (Weatherization	Insulation, Wood Pellets	E21B1a028	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Cord Wood	E21B1a077	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Electric	E21B1a078	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Gas	E21B1a079	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Kerosene	E21B1a080	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Oil	E21B1a081	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Propane	E21B1a082	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Wood Pellets	E21B1a083	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Electric	E21B1a030	7	7	0.9	0.9	13.9	13.9	0.2	0.2	0.1	0.1	-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Gas	E21B1a031	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Kerosene	E21B1a032	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Oil	E21B1a033	12	12	-	-	-	-	-	-	-	-	6.9	6.9	103.7	103.7
B1a - HEA (Weatherization	Low Flow Showerhead, Propane	E21B1a034	15	15	-	-	-	-	-	-	-	-	8.6	8.6	129.6	129.6

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Electric	E21B1a037	18	18	-	-	-	-	-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Gas	E21B1a038	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Kerosene	E21B1a039	-	-									-	-	-	-
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Oil	E21B1a040	14	14	-	-	-	-	-	-	-	-	6.4	6.4	95.6	95.6
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Propane	E21B1a041	5	5	-	-	-	-	-	-	-	-	2.3	2.3	34.1	34.1
B1a - HEA (Weatherization	Hot Water Setback, Electric	E21B1a042	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Gas	E21B1a060	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Kerosene	E21B1a061	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Oil	E21B1a062	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback, Propane	E21B1a063	-	-									-	-	-	-
B1a - HEA (Weatherization	DHW Heat Pump Water Heater	E21B1a043	12	12	19.9	19.9	258.1	258.1	3.3	3.3	1.8	1.8	-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Electric	E21B1a096	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Gas	E21B1a097	-	-									-	-	-	-
B1a - HEA (Weatherization	Stand Alone Water Heater, Propane	E21B1a099	-	-									-	-	-	-
B1a - HEA (Weatherization	Indirect Water Heater, Oil	E21B1a098	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, General Service Lamps	E21B1a044	235	200	7.5	6.4	15.1	12.8	1.6	1.4	1.1	0.9	(17.2)	(14.6)	(34.3)	(29.2)
B1a - HEA (Weatherization	LED Bulb, Linear	E21B1a045	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Other Specialty	E21B1a046	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Reflector	E21B1a047	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Fixture	E21B1a048	-	-									-	-	-	-
B1a - HEA (Weatherization	Refrigerator	E21B1a049	80	80	61.3	61.3	735.6	735.6	7.0	7.0	8.6	8.6	-	-	-	-
B1a - HEA (Weatherization	Freezer	E21B1a050	-	-									-	-	-	-
B1a - HEA (Weatherization	Clothes Washer	E21B1a051	25	25	2.0	2.0	22.3	22.3	0.3	0.3	0.3	0.3	2.6	2.6	29.0	29.0
B1a - HEA (Weatherization	Clothes Dryer	E21B1a052	-	-									-	-	-	-
B1a - HEA (Weatherization	Dehumidifier	E21B1a053	-	-									-	-	-	-
B1a - HEA (Weatherization	Room Air Conditioner	E21B1a054	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Cord Wood	E21B1a055	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Electric	E21B1a064	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Gas	E21B1a065	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Kerosene	E21B1a066	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Oil	E21B1a067	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Propane	E21B1a068	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Replacement, Wood Pellets	E21B1a069	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Cord Wood	E21B1a100	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Electric	E21B1a101	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Gas	E21B1a102	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Kerosene	E21B1a103	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Oil	E21B1a104	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Propane	E21B1a105	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert, Wood Pellets	E21B1a106	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Cord Wood	E21B1a070	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Electric	E21B1a071	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Gas	E21B1a072	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Kerosene	E21B1a073	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Oil	E21B1a074	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Propane	E21B1a075	-	-									-	-	-	-
B1a - HEA (Weatherization	Insulated Door, Wood Pellets	E21B1a076	-	-									-	-	-	-
B1a - HEA (Weatherization	Visual Audit	E21B1a056	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Baseload Audit - SF	E21B1a057	75	80	-	-	-	-	-	-	-	-	-	-	-	-
B1a - HEA (Weatherization	Baseload Audit - MF	E21B1a058	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Income Kits	E21B1a059	-	-									-	-	-	-
			-	-									-	-	-	-
B1b - HEA (HVAC System	Boiler Replacement, Gas	E21B1b001	-	-									-	-	-	-
B1b - HEA (HVAC System	Boiler Replacement, Kerosene	E21B1b002	-	-									-	-	-	-
B1b - HEA (HVAC System	Boiler Replacement, Oil	E21B1b003	6	6	-	-	-	-	-	-	-	-	65.5	65.5	1,244.9	1,244.9
B1b - HEA (HVAC System	Boiler Replacement, Propane	E21B1b004	-	-									-	-	-	-
B1b - HEA (HVAC System	Furnace Replacement, Gas	E21B1b005	-	-									-	-	-	-
B1b - HEA (HVAC System	Furnace Replacement, Kerosene	E21B1b006	5	6	0.4	0.5	6.8	7.7	0.1	0.2	-	-	36.4	41.5	618.8	705.4
B1b - HEA (HVAC System	Furnace Replacement, Oil	E21B1b007	4	5	0.5	0.6	8.1	10.1	0.1	0.1	-	-	43.7	54.6	742.6	928.2
B1b - HEA (HVAC System	Furnace Replacement, Propane	E21B1b008	5	5	0.6	0.6	10.1	10.1	0.1	0.1	-	-	54.6	54.6	928.2	928.2
B1b - HEA (HVAC System	Programmable Thermostat, Electric	E21B1b009	-	-									-	-	-	-
B1b - HEA (HVAC System	Programmable Thermostat, Gas	E21B1b010	-	-									-	-	-	-
B1b - HEA (HVAC System	Programmable Thermostat, Kerosene	E21B1b011	-	-									-	-	-	-
B1b - HEA (HVAC System	Programmable Thermostat, Oil	E21B1b012	-	-									-	-	-	-
B1b - HEA (HVAC System	Programmable Thermostat, Propane	E21B1b013	8	8	-	-	-	-	-	-	-	-	25.5	25.5	382.2	382.2
B1b - HEA (HVAC System	Programmable Thermostat, Wood Pellets	E21B1b014	-	-									-	-	-	-
B1b - HEA (HVAC System	Wifi Thermostat, Electric	E21B1b015	-	-									-	-	-	-
B1b - HEA (HVAC System	Wifi Thermostat, Gas	E21B1b016	-	-									-	-	-	-
B1b - HEA (HVAC System	Wifi Thermostat, Kerosene	E21B1b017	-	-									-	-	-	-
B1b - HEA (HVAC System	Wifi Thermostat, Oil	E21B1b018	4	4	-	-	-	-	-	-	-	-	21.5	21.5	322.1	322.1
B1b - HEA (HVAC System	Wifi Thermostat, Propane	E21B1b019	5	5	-	-	-	-	-	-	-	-	26.4	26.4	395.9	395.9
B1b - HEA (HVAC System	Wifi Thermostat, Wood Pellets	E21B1b020	-	-									-	-	-	-
B1b - HEA (HVAC System	Mini Split HP (cooling)	E21B1b021	2	2	0.4	0.4	6.6	6.6	-	-	0.2	0.2	-	-	-	-
B1b - HEA (HVAC System	Mini Split HP (heating)	E21B1b022	2	2	2.2	2.2	39.3	39.3	0.7	0.7	-	-	-	-	-	-
B1b - HEA (HVAC System	ES Central AC	E21B1b023	-	-									-	-	-	-
B1b - HEA (HVAC System	Oil K1 HVAC Repair or Cleaning	E21B1b024	-	-									-	-	-	-
B1b - HEA (HVAC System	Gas LP HVAC Repair or Cleaning	E21B1b025	-	-									-	-	-	-
	Home Energy Assistance Subtotal				**142.4**	**144.4**	**2,096.2**	**2,159.0**	**21.9**	**21.7**	**22.7**	**24.2**	**2,124.8**	**2,425.5**	**43,427.1**	**49,628.6**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A1a - ES Homes	Cooling, Electric, SF	E21A1a001	6	7	1.2	1.4	30.0	35.0	-	-	0.7	0.8	-	-	-	-
A1a - ES Homes	Heating, Electric, SF	E21A1a002	15	15	75.0	75.0	1,875.0	1,875.0	23.8	23.8	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, SF	E21A1a003	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, SF	E21A1a004	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, SF	E21A1a005	82	85	16.4	17.0	410.0	425.0	4.8	-	-	-	984.0	1,020.0	24,600.0	25,500.0
A1a - ES Homes	Heating, Wood Pellets, SF	E21A1a006	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, SF	E21A1a007	20	20	5.0	5.0	75.0	75.0	1.0	1.0	0.4	0.4	-	-	-	-
A1a - ES Homes	Hot Water, Gas, SF	E21A1a008	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, SF	E21A1a009	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, SF	E21A1a010	15	15	-	-	-	-	-	-	-	-	30.0	30.0	450.0	450.0
A1a - ES Homes	Hot Water, Wood Pellets, SF	E21A1a011	-	-									-	-	-	-
A1a - ES Homes	Cooling, Electric, MF	E21A1a012	8	5	0.8	0.5	20.0	12.5	-	-	0.4	0.3	-	-	-	-
A1a - ES Homes	Heating, Electric, MF	E21A1a013	10	6	20.0	12.0	500.0	300.0	6.3	3.8	-	-	-	-	-	-
A1a - ES Homes	Heating, Gas, MF	E21A1a014	-	-									-	-	-	-
A1a - ES Homes	Heating, Oil, MF	E21A1a015	-	-									-	-	-	-
A1a - ES Homes	Heating, Propane, MF	E21A1a016	51	60	-	-	-	-	-	-	-	-	510.0	600.0	12,750.0	15,000.0
A1a - ES Homes	Heating, Wood Pellets, MF	E21A1a017	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Electric, MF	E21A1a018	12	15	6.0	7.5	90.0	112.5	1.2	1.5	0.5	0.6	-	-	-	-
A1a - ES Homes	Hot Water, Gas, MF	E21A1a019	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Oil, MF	E21A1a020	-	-									-	-	-	-
A1a - ES Homes	Hot Water, Propane, MF	E21A1a021	20	20	-	-	-	-	-	-	-	-	40.0	40.0	600.0	600.0
A1a - ES Homes	Hot Water, Wood Pellets, MF	E21A1a022	-	-									-	-	-	-
A1a - ES Homes	LED Bulb	E21A1a023	-	-									-	-	-	-
A1a - ES Homes	LED Fixture	E21A1a024	-	-									-	-	-	-
A1a - ES Homes	Refrigerator	E21A1a025	-	-									-	-	-	-
A1a - ES Homes	Clothes Washer	E21A1a026	-	-									-	-	-	-
A1a - ES Homes	Clothes Dryer	E21A1a027	-	-									-	-	-	-
A1a - ES Homes	HERS - Lighting and Appliances	E21A1a028	40	40	-	-	-	-	-	-	-	-	-	-	-	-
A1a - ES Homes	Residential New Construction Code Complianc	E21A1a029	-	-									-	-	-	-
	ES Homes Subtotal				**124.4**	**118.4**	**3,000.0**	**2,835.0**	**37.1**	**30.1**	**1.9**	**2.0**	**1,564.0**	**1,690.0**	**38,400.0**	**41,550.0**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatheriza	Air Sealing, Cord Wood	E21A2a001	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Air Sealing, Electric	E21A2a002	12	12	45.6	45.6	684.3	684.3	14.5	14.5	-	-	-	-	-	-
A2a - HPwES (Weatheriza	Air Sealing, Gas	E21A2a003	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Air Sealing, Kerosene	E21A2a004	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Air Sealing, Oil	E21A2a005	22	24	2.8	3.0	41.8	45.6	-	-	1.5	1.7	198.6	216.7	2,979.5	3,250.4
A2a - HPwES (Weatheriza	Air Sealing, Propane	E21A2a006	32	32	4.0	4.0	60.7	60.7	-	-	2.2	2.2	288.9	288.9	4,333.8	4,333.8
A2a - HPwES (Weatheriza	Air Sealing, Wood Pellets	E21A2a007	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Cord Wood	E21A2a070	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Electric	E21A2a071	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Gas	E21A2a072	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Kerosene	E21A2a073	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Oil	E21A2a074	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Propane	E21A2a075	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Sealing, Wood Pellets	E21A2a076	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Faucet Aerator, Electric	E21A2a009	45	45	2.0	2.0	14.0	14.0	0.4	0.4	0.2	0.2	-	-	-	-
A2a - HPwES (Weatheriza	Faucet Aerator, Gas	E21A2a010	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Faucet Aerator, Kerosene	E21A2a011	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Faucet Aerator, Oil	E21A2a012	45	45	-	-	-	-	-	-	-	-	7.9	7.9	55.5	55.5
A2a - HPwES (Weatheriza	Faucet Aerator, Propane	E21A2a013	25	25	-	-	-	-	-	-	-	-	4.4	4.4	30.8	30.8
A2a - HPwES (Weatheriza	Tank Wrap, Electric	E21A2a077	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Tank Wrap, Gas	E21A2a078	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Tank Wrap, Kerosene	E21A2a079	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Tank Wrap, Oil	E21A2a080	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Tank Wrap, Propane	E21A2a081	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hand Held Showerhead, Electric	E21A2a016	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hand Held Showerhead, Gas	E21A2a017	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hand Held Showerhead, Kerosene	E21A2a018	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hand Held Showerhead, Oil	E21A2a019	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hand Held Showerhead, Propane	E21A2a020	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Insulation, Cord Wood	E21A2a022	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Insulation, Electric	E21A2a023	12	12	68.4	68.4	1,710.7	1,710.7	21.7	21.7	-	-	-	-	-	-
A2a - HPwES (Weatheriza	Insulation, Gas	E21A2a024	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Insulation, Kerosene	E21A2a025	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Insulation, Oil	E21A2a026	22	24	6.3	6.8	156.8	171.1	-	-	3.5	3.8	372.4	406.3	9,311.0	10,157.4
A2a - HPwES (Weatheriza	Insulation, Propane	E21A2a027	32	32	9.1	9.1	228.1	228.1	-	-	5.0	5.0	541.7	541.7	13,543.2	13,543.2
A2a - HPwES (Weatheriza	Insulation, Wood Pellets	E21A2a028	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Cord Wood	E21A2a063	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Electric	E21A2a064	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Gas	E21A2a065	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Kerosene	E21A2a066	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Oil	E21A2a067	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Propane	E21A2a068	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Duct Insulation, Wood Pellets	E21A2a069	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Low Flow Showerhead, Electric	E21A2a030	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Low Flow Showerhead, Gas	E21A2a031	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Low Flow Showerhead, Kerosene	E21A2a032	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Low Flow Showerhead, Oil	E21A2a033	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Low Flow Showerhead, Propane	E21A2a034	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kW		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatheriza	Pipe Insulation - Hot Water, Electric	E21A2a037	10	10	1.0	1.0	14.3	14.3	0.2	0.2	0.1	0.1	-	-	-	-
A2a - HPwES (Weatheriza	Pipe Insulation - Hot Water, Gas	E21A2a038	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Pipe Insulation - Hot Water, Kerosene	E21A2a039	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Pipe Insulation - Hot Water, Oil	E21A2a040	25	25	-	-	-	-	-	-	-	-	5.6	5.6	84.6	84.6
A2a - HPwES (Weatheriza	Pipe Insulation - Hot Water, Propane	E21A2a041	20	20	-	-	-	-	-	-	-	-	4.5	4.5	67.7	67.7
A2a - HPwES (Weatheriza	Hot Water Setback, Electric	E21A2a042	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hot Water Setback, Gas	E21A2a059	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hot Water Setback, Kerosene	E21A2a060	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hot Water Setback, Oil	E21A2a061	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Hot Water Setback, Propane	E21A2a062	-	-									-	-	-	-
A2a - HPwES (Weatheriza	DHW Heat Pump Water Heater	E21A2a043	7	7	12.1	12.1	157.2	157.2	2.0	2.0	1.1	1.1	-	-	-	-
A2a - HPwES (Weatheriza	Indirect Water Heater, Oil	E21A2a082	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Indirect Water Heater, Propane	E21A2a083	-	-									-	-	-	-
A2a - HPwES (Weatheriza	LED Bulb, General Service Lamps	E21A2a044	-	-									-	-	-	-
A2a - HPwES (Weatheriza	LED Bulb, Linear	E21A2a045	-	-									-	-	-	-
A2a - HPwES (Weatheriza	LED Bulb, Other Specialty	E21A2a046	-	-									-	-	-	-
A2a - HPwES (Weatheriza	LED Bulb, Reflector	E21A2a047	-	-									-	-	-	-
A2a - HPwES (Weatheriza	LED Fixture	E21A2a048	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Refrigerator	E21A2a049	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Freezer	E21A2a053	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Clothes Washer	E21A2a054	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Clothes Dryer	E21A2a055	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Dehumidifier	E21A2a056	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Room Air Conditioner	E21A2a057	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Triple Pane Window	E21A2a058	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Cord Wood	E21A2a084	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Electric	E21A2a085	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Gas	E21A2a086	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Kerosene	E21A2a087	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Oil	E21A2a088	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Propane	E21A2a089	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Window Insert, Wood Pellets	E21A2a090	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Visual Audit Oil Savings	E21A2a050	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Visual Audit Propane Savings	E21A2a051	-	-									-	-	-	-
A2a - HPwES (Weatheriza	Visual Audit Electric Savings	E21A2a052	-	-									-	-	-	-
													-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Gas	E21A2b001	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Kerosene	E21A2b002	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Oil	E21A2b003	1	1	-	-	-	-	-	-	-	-	9.9	9.9	188.1	188.1
A2b - HPwES (HVAC Syste	Boiler Replacement, Propane	E21A2b004	1	2	-	-	-	-	-	-	-	-	9.9	19.8	188.1	376.2
A2b - HPwES (HVAC Syste	Furnace Replacement, Gas	E21A2b005	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Kerosene	E21A2b006	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Oil	E21A2b007	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Propane	E21A2b008	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Electric	E21A2b009	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Gas	E21A2b010	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Kerosene	E21A2b011	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Oil	E21A2b012	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2b - HPwES (HVAC Syste	Programmable Thermostat, Propane	E21A2b013	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Wood Pellets	E21A2b014	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Electric	E21A2b015	13	13	5.2	5.2	77.7	77.7	-	-	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Gas	E21A2b016	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Kerosene	E21A2b017	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Wifi Thermostat, Oil	E21A2b018	35	35	-	-	-	-	-	-	-	-	233.1	233.1	3,495.8	3,495.8
A2b - HPwES (HVAC Syste	Wifi Thermostat, Propane	E21A2b019	20	20	-	-	-	-	-	-	-	-	130.9	130.9	1,963.8	1,963.8
A2b - HPwES (HVAC Syste	Wifi Thermostat, Wood Pellets	E21A2b020	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	ES Central AC	E21A2b021	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Boiler Circulator Pump	E21A2b022	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Furnace	E21A2b023	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Central AC	E21A2b024	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Room AC	E21A2b025	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Mini-Split AC / HP	E21A2b026	-	-									-	-	-	-
	Home Performance with Energy Star Subtotal				**156.5**	**157.3**	**3,145.6**	**3,163.6**	**38.8**	**38.8**	**13.6**	**14.0**	**1,808.0**	**1,869.8**	**36,241.9**	**37,547.3**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A3a - ES Lighting	LED Bulb, General Service Lamps	E21A3a001	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Linear	E21A3a002	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Other Specialty	E21A3a003	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, Reflector	E21A3a004	-	-									-	-	-	-
A3a - ES Lighting	LED Bulb, General Service Lamps (Hard to Re	E21A3a005	10,500	11,000	119.2	95.8	357.6	191.7	25.7	20.7	16.6	13.3	(270.8)	(217.7)	(812.5)	(435.5)
A3a - ES Lighting	LED Bulb, Linear (Hard to Reach)	E21A3a006	950	1,300	3.8	4.0	38.2	36.1	0.8	0.9	0.5	0.6	(8.7)	(9.1)	(86.7)	(82.0)
A3a - ES Lighting	LED Bulb, Other Specialty (Hard to Reach)	E21A3a007	1,000	1,000	10.3	7.9	30.8	15.7	2.2	1.7	1.4	1.1	(23.3)	(17.9)	(69.9)	(35.8)
A3a - ES Lighting	LED Bulb, Reflector (Hard to Reach)	E21A3a008	600	600	7.6	5.8	15.2	5.8	1.6	1.3	1.1	0.8	(17.2)	(13.2)	(34.4)	(13.2)
A3a - ES Lighting	LED Fixture	E21A3a009	-	-									-	-	-	-
A3a - ES Lighting	LED Fixture (Hard to Reach)	E21A3a010	-	-									-	-	-	-
													-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier I	E21A3b001	-	-									-	-	-	-
A3b - ES Appliances	Advanced Power Strip, Tier II	E21A3b002	150	150	18.0	18.0	90.0	90.0	1.6	1.6	1.1	1.1	-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (cool	E21A3b003	10	10	2.2	2.1	39.6	37.5	-	-	1.2	1.1	-	-	-	-
A3c - ES HVAC Systems	Air Source Heat Pump - Lost Opportunity (hea	E21A3b004	10	10	20.9	9.4	375.7	168.9	9.5	4.3	-	-	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (cooling)	E21A3b005	380	380	52.2	43.9	938.7	789.7	-	-	24.1	20.3	-	-	-	-
A3c - ES HVAC Systems	Mini Split HP - Lost Opportunity (heating)	E21A3b006	380	380	166.1	145.3	2,989.1	2,614.7	75.5	66.0	-	-	-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Down	E21A3b007	80	80	76.9	76.9	999.4	999.4	12.6	12.6	7.0	7.0	171.9	171.9	2,235.0	2,235.0
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Down	E21A3b008	18	18	10.2	10.2	132.2	132.2	1.7	1.7	0.9	0.9	38.7	38.7	502.9	502.9
A3b - ES Appliances	Heat Pump Swimming Pool Heater	E21A3b009	-	-									-	-	-	-
A3b - ES Appliances	ES Clothes Dryers	E21A3b010	100	100	16.0	16.0	192.5	192.5	2.7	2.7	2.1	2.1	-	-	-	-
A3b - ES Appliances	Dryer Heat Pump	E21A3b011	25	25	10.5	10.5	126.3	126.3	1.8	1.8	1.4	1.4	-	-	-	-
A3b - ES Appliances	Dryer Hybrid	E21A3b012	9	9	1.9	1.9	23.0	23.0	0.3	0.3	0.3	0.3	-	-	-	-
A3b - ES Appliances	ECM Motor for FWH Circulating Pump	E21A3b013	-	-									-	-	-	-
A3c - ES HVAC Systems	ES AC (central) 3 ton	E21A3b015	-	-									-	-	-	-
A3b - ES Appliances	Room Air Conditioner	E21A3b016	125	125	4.1	4.1	37.1	37.1	-	-	2.1	2.1	-	-	-	-
A3b - ES Appliances	ES Clothes Washers	E21A3b017	225	250	20.2	22.5	222.5	247.2	2.8	3.2	2.7	3.0	15.8	17.5	173.3	192.5
A3b - ES Appliances	Washer Tier CEE Tier 2+	E21A3b018	175	200	24.3	27.8	267.4	305.6	3.4	3.9	3.2	3.7	84.0	96.0	924.0	1,056.0
A3b - ES Appliances	ES Dehumidifier	E21A3b019	200	230	16.5	18.9	197.5	227.1	0.7	0.8	3.2	3.6	-	-	-	-
A3b - ES Appliances	ES Dishwasher	E21A3b020	-	-									-	-	-	-
A3b - ES Appliances	ES Freezers	E21A3b021	-	-									-	-	-	-
A3b - ES Appliances	Refrigerator	E21A3b022	300	300	13.3	13.3	159.1	159.1	1.5	1.5	1.9	1.9	-	-	-	-
A3b - ES Appliances	Refrigerator CEE Tier 2+	E21A3b023	86	86	8.3	8.3	99.5	99.5	0.9	0.9	1.2	1.2	-	-	-	-
A3b - ES Appliances	ES Pool Pumps (Variable Speed)	E21A3b024	13	13	16.7	16.7	166.9	166.9	-	-	9.6	9.6	-	-	-	-
A3b - ES Appliances	Room Air Purifier	E21A3b025	100	125	37.9	47.3	340.9	426.1	4.3	5.4	4.3	5.4	-	-	-	-
A3c - ES HVAC Systems	Wifi Thermostat (Heating & Cooling)	E21A3b026	100	100	4.6	4.6	69.0	69.0	-	-	-	-	492.0	492.0	7,380.0	7,380.0
A3b - ES Appliances	Primary Refrigerator Recycling	E21A3b027	100	120	102.7	123.2	513.5	616.2	11.7	14.1	14.4	17.3	-	-	-	-
A3b - ES Appliances	Secondary Refrigerator Recycling	E21A3b028	20	30	20.5	30.8	102.7	154.1	1.9	2.9	3.2	4.8	-	-	-	-
A3b - ES Appliances	Secondary Freezer Recycling	E21A3b029	20	30	15.4	23.1	61.5	92.3	1.5	2.3	2.0	3.0	-	-	-	-
A3b - ES Appliances	Room Air Conditioner Recycling	E21A3b030	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit Resist	E21A3b031	-	-									-	-	-	-
A3c - ES HVAC Systems	Ductless Mini-split Heat Pump - Retrofit HP	E21A3b032	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit HP	E21A3b033	-	-									-	-	-	-
A3c - ES HVAC Systems	Air-source Heat Pump – Retrofit Resistance	E21A3b034	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 50 gal - Midstr	E21A3b035	-	-									-	-	-	-
A3c - ES HVAC Systems	DHW Heat Pump Water Heater 80 gal - Midstr	E21A3b036	-	-									-	-	-	-
	ES Products Subtotal				**800.1**	**788.3**	**8,586.0**	**8,024.0**	**165.0**	**150.5**	**105.5**	**105.6**	**482.3**	**558.2**	**10,211.5**	**10,799.9**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1a - LCI Retrofit	Custom Large Compressed Air Retro	E21C1a001	3	4	171.0	228.0	2,223.0	2,964.0	33.3	-	33.3	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Hot Water Retro	E21C1a002	2	3	144.0	216.0	1,440.0	2,160.0	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Custom Large HVAC Retro	E21C1a003	3	3	167.4	167.4	2,511.0	2,511.0	79.1	-	65.1	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Interior	E21C1a004	15	15	444.6	419.6	4,445.6	3,356.6	67.9	51.2	89.0	67.2	(267.5)	(252.5)	(2,675.2)	(2,019.9)
C1a - LCI Retrofit	Custom Large Lighting Retro - Exterior	E21C1a047	10	10	296.4	279.7	2,963.7	2,517.5	74.2	56.0	-	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Lighting Retro - Controls	E21C1a048	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Motors Retro	E21C1a005	1	2	61.1	122.1	793.9	1,587.9	10.7	-	10.9	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Process Retro	E21C1a006	2	2	190.0	190.0	2,470.0	2,470.0	33.3	-	35.2	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Refrigeration Retro	E21C1a007	1	1	85.5	85.5	1,111.5	1,111.5	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Custom Large Other Retro	E21C1a008	-	-									-	-	-	-
C1a - LCI Retrofit	Daylight Dimming	E21C1a009	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C1a010	10	15	39.2	55.5	392.3	555.3	7.9	11.1	-	-	-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C1a011	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C1a012	45	45	17.9	16.9	179.0	168.9	1.4	1.3	1.8	1.7	(12.4)	(11.7)	(123.8)	(116.9)
C1a - LCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C1a013	-	-									-	-	-	-
C1a - LCI Retrofit	Lighting Occupancy Sensors	E21C1a014	25	25	3.5	3.3	31.4	29.6	49.7	0.0	51.2	0.0	(9.5)	(9.0)	(85.7)	(80.9)
C1a - LCI Retrofit	Boiler Reset Controls, Electric	E21C1a015	-	-									-	-	-	-
C1a - LCI Retrofit	Case Motor Replacement	E21C1a016	-	-									-	-	-	-
C1a - LCI Retrofit	Cooler Night Cover	E21C1a017	-	-									-	-	-	-
C1a - LCI Retrofit	Demand Control Ventilation	E21C1a018	-	-									-	-	-	-
C1a - LCI Retrofit	Door Heater Controls	E21C1a019	-	-									-	-	-	-
C1a - LCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C1a020	-	-									-	-	-	-
C1a - LCI Retrofit	Duct Sealing, Electric	E21C1a021	-	-									-	-	-	-
C1a - LCI Retrofit	Ductless Mini Split Heat Pump	E21C1a022	-	-									-	-	-	-
C1a - LCI Retrofit	ECM Evaporator Fan Motors for Walk-in Coole	E21C1a023	-	-									-	-	-	-
C1a - LCI Retrofit	Electronic Defrost Control	E21C1a024	-	-									-	-	-	-
C1a - LCI Retrofit	Energy Management System, Electric	E21C1a025	1	1	40.0	40.0	399.6	399.6	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C1a026	-	-									-	-	-	-
C1a - LCI Retrofit	Evaporator Fan Control	E21C1a027	-	-									-	-	-	-
C1a - LCI Retrofit	Faucet Aerator, Electric	E21C1a028	-	-									-	-	-	-
C1a - LCI Retrofit	Hotel Occupancy Sensor	E21C1a031	45	50	19.7	21.9	196.9	218.8	0.2	0.2	3.3	3.7	-	-	-	-
C1a - LCI Retrofit	Low Pressure Drop Filter	E21C1a032	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C1a033	-	-									-	-	-	-
C1a - LCI Retrofit	Low-Flow Showerhead, Electric	E21C1a034	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Open Drip	E21C1a035	-	-									-	-	-	-
C1a - LCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C1a036	-	-									-	-	-	-
C1a - LCI Retrofit	Novelty Cooler Shutoff	E21C1a037	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Heating, Electric	E21C1a038	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C1a039	-	-									-	-	-	-
C1a - LCI Retrofit	Pre Rinse Spray Valve, Electric	E21C1a040	-	-									-	-	-	-
C1a - LCI Retrofit	Programmable Thermostat, Electric	E21C1a041	-	-									-	-	-	-
C1a - LCI Retrofit	Steam Trap, Electric	E21C1a042	-	-									-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive	E21C1a043	4	4	7.6	7.6	113.5	113.5	-	-	-	-	-	-	-	-
C1a - LCI Retrofit	Variable Frequency Drive with Motor	E21C1a044	-	-									-	-	-	-
C1a - LCI Retrofit	Vending Miser	E21C1a045	-	-									-	-	-	-
C1a - LCI Retrofit	Zero Loss Condensate Drain	E21C1a046	-	-									-	-	-	-
C1a - LCI Retrofit	Large Retrocommissioning	E21C1a049	-	-									-	-	-	-
													-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kW		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1b - LCI New Equipment	Custom Large Compressed Air New	E21C1b001	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Hot Water New	E21C1b002	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large HVAC New	E21C1b003	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Interior	E21C1b004	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Exterior	E21C1b054	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Lighting New - Controls	E21C1b055	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Motors New	E21C1b005	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Process New	E21C1b006	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Refrigeration New	E21C1b007	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Other New	E21C1b008	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Comprehensive Design	E21C1b056	-	-									-	-	-	-
C1b - LCI New Equipment	Daylight Dimming	E21C1b009	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C1b010	75	78	19.6	19.3	294.5	289.1	3.9	3.9	-	-	-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C1b011	-	-									-	-	-	-
C1b - LCI New Equipment	Performance Lighting - Interior w/ Controls	E21C1b012	85	85	18.9	17.8	283.4	267.5	1.5	1.4	1.9	1.8	(3.1)	(2.9)	(46.0)	(43.5)
C1b - LCI New Equipment	Performance Lighting - Interior w/o Controls	E21C1b013	-	-									-	-	-	-
C1b - LCI New Equipment	Lighting Occupancy Sensors	E21C1b014	55	65	4.1	4.5	40.7	45.5	0.1	0.1	0.1	0.1	(11.1)	(12.4)	(111.3)	(124.1)
C1b - LCI New Equipment	Advanced Power Strip	E21C1b015	-	-									-	-	-	-
C1b - LCI New Equipment	Air Compressor	E21C1b016	-	-									-	-	-	-
C1b - LCI New Equipment	Air Nozzle	E21C1b017	-	-									-	-	-	-
C1b - LCI New Equipment	Circulator Pump	E21C1b018	-	-									-	-	-	-
C1b - LCI New Equipment	Combination Oven, Electric	E21C1b019	-	-									-	-	-	-
C1b - LCI New Equipment	Compressor Storage	E21C1b020	-	-									-	-	-	-
C1b - LCI New Equipment	Convection Oven, Electric	E21C1b021	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Door Type	E21C1b022	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C1b023	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C1b024	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Single Tank Conveyo	E21C1b025	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - High Temp Under Counter	E21C1b026	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Door Type	E21C1b027	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C1b028	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Single Tank Conveyo	E21C1b029	-	-									-	-	-	-
C1b - LCI New Equipment	Dishwasher - Low Temp Under Counter	E21C1b030	-	-									-	-	-	-
C1b - LCI New Equipment	Faucet Aerator, Electric	E21C1b031	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Large Vat, Electric	E21C1b032	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer Standard Vat, Electric	E21C1b033	-	-									-	-	-	-
C1b - LCI New Equipment	Griddle, Electric	E21C1b034	-	-									-	-	-	-
C1b - LCI New Equipment	Ground Source Heat Pump	E21C1b035	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C1b036	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Full Size	E21C1b037	-	-									-	-	-	-
C1b - LCI New Equipment	Hot Food Holding Cabinet Half Size	E21C1b038	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Ice Making Head	E21C1b039	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C1b040	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Remote Cond./Split Unit - Contir	E21C1b041	-	-									-	-	-	-
C1b - LCI New Equipment	Ice Machine - Self Contained	E21C1b042	-	-									-	-	-	-
C1b - LCI New Equipment	Low Pressure Drop Filter	E21C1b043	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead With Thermostatic Valv	E21C1b044	-	-									-	-	-	-
C1b - LCI New Equipment	Low-Flow Showerhead, Electric	E21C1b045	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1b - LCI New Equipment	Pre Rinse Spray Valve, Electric	E21C1b046	-	-									-	-	-	-
C1b - LCI New Equipment	Refrigerated Air Dryer	E21C1b047	-	-									-	-	-	-
C1b - LCI New Equipment	Steam Cooker, Electric	E21C1b048	-	-									-	-	-	-
C1b - LCI New Equipment	Unitary Air Conditioner	E21C1b049	-	-									-	-	-	-
C1b - LCI New Equipment	Water Source Heat Pump	E21C1b050	-	-									-	-	-	-
C1b - LCI New Equipment	Zero Loss Condensate Drain	E21C1b051	-	-									-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - FL	E21C1b052	4	5	139.9	174.8	3,216.8	4,021.0	-	-	-	-	-	-	-	-
C1b - LCI New Equipment	High Efficiency Chiller - IPLV	E21C1b053	-	-									-	-	-	-
C1b - LCI New Equipment	C&I Large New Construction Code Complianc	E21C1b057	-	-									-	-	-	-
													-	-	-	-
C1c - LCI Midstream	Midstream Circulator Pump	E21C1c001	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Demand Control Ventilation	E21C1c002	-	-									-	-	-	-
C1c - LCI Midstream	Midstream DMSHP Systems	E21C1c003	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C1c004	-	-									-	-	-	-
C1c - LCI Midstream	Midstream ECM Fan Motors	E21C1c005	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Systems	E21C1c006	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Unitary Air Conditioners	E21C1c007	-	-									-	-	-	-
C1c - LCI Midstream	Midstream VRF	E21C1c008	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Water Source Heat Pump Systems	E21C1c009	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Downlight	E21C1c010	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Exterior	E21C1c011	220	220	58.0	52.7	564.9	513.5	11.7	10.7	-	-	-	-	-	-
C1c - LCI Midstream	Midstream LED High Bay/Low Bay	E21C1c012	375	350	173.4	147.1	2,177.3	1,847.4	30.2	25.6	38.5	32.7	(37.6)	(31.9)	(472.2)	(400.6)
C1c - LCI Midstream	Midstream LED Linear Fixture	E21C1c013	240	200	50.9	38.6	559.6	423.9	5.8	4.4	7.4	5.6	(7.3)	(5.5)	(79.9)	(60.5)
C1c - LCI Midstream	Midstream LED Linear Fixture with Controls	E21C1c014	40	35	8.5	6.8	93.3	74.2	0.5	0.4	0.6	0.5	(1.2)	(1.0)	(13.3)	(10.6)
C1c - LCI Midstream	Midstream LED Linear Lamp	E21C1c015	600	475	30.8	22.2	324.6	233.6	3.5	2.5	4.5	3.2	(4.4)	(3.2)	(46.3)	(33.3)
C1c - LCI Midstream	Midstream LED Screw In	E21C1c016	-	-									-	-	-	-
C1c - LCI Midstream	Midstream LED Stairwell Kit	E21C1c017	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Combination Oven, Electric	E21C1c018	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Convection Oven, Electric	E21C1c019	2	5	4.8	12.0	57.5	143.8	1.1	2.7	1.1	2.7	-	-	-	-
C1c - LCI Midstream	Midstream Conveyor Broiler	E21C1c047	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Deck Oven, Electric	E21C1c050	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C1c020	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Multi Tank	E21C1c021	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Pot, Pan,	E21C1c022	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Single Ta	E21C1c023	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - High Temp Under Co	E21C1c024	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C1c025	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Multi Tank	E21C1c026	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Single Tar	E21C1c027	5	5	50.2	50.2	1,004.9	1,004.9	8.0	8.0	8.0	8.0	-	-	-	-
C1c - LCI Midstream	Midstream Dishwasher - Low Temp Under Cou	E21C1c028	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Solid Door	E21C1c029	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Freezer - Glass Door	E21C1c030	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Large Vat, Electric	E21C1c031	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer Standard Vat, Electric	E21C1c032	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Griddle, Electric	E21C1c033	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hand-Wrap Machine	E21C1c051	-	-									-	-	-	-
C1c - LCI Midstream	Midstream High Efficiency Condensing Unit	E21C1c052	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C1c034	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C1c035	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C1c036	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Ice Making Head	E21C1c037	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Un	E21C1c038	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Remote Cond/Split Un	E21C1c039	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ice Machine Self Contained	E21C1c040	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerated Chef Base	E21C1c053	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Glass Door	E21C1c041	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Refrigerator - Solid Door	E21C1c042	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Steam Cooker, Electric	E21C1c043	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Ultra Low-Temp Freezer	E21C1c048	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 120 gall	E21C1c044	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 50 gallon	E21C1c045	25	25	19.7	19.7	255.6	255.6	3.2	3.2	1.8	1.8	-	-	-	-
C1c - LCI Midstream	Midstream Heat Pump Water Heater, 80 gallon	E21C1c046	-	-									-	-	-	-
													-	-	-	-
C1d - LCI Direct Install	Custom Large Compressed Air Direct Install	E21C1d001	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Hot Water Direct Install	E21C1d002	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large HVAC Direct Install	E21C1d003	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Interior	E21C1d004	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Exterior	E21C1d005	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Lighting Direct Install - Controls	E21C1d006	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Motors Direct Install	E21C1d007	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Process Direct Install	E21C1d008	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Refrigeration Direct Install	E21C1d009	-	-									-	-	-	-
C1d - LCI Direct Install	Custom Large Other Direct Install	E21C1d010	-	-									-	-	-	-
C1d - LCI Direct Install	Daylight Dimming	E21C1d011	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C1d012	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C1d013	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C1d014	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C1d015	-	-									-	-	-	-
C1d - LCI Direct Install	Lighting Occupancy Sensors	E21C1d016	-	-									-	-	-	-
C1d - LCI Direct Install	Boiler Reset Controls, Electric	E21C1d017	-	-									-	-	-	-
C1d - LCI Direct Install	Case Motor Replacement	E21C1d018	-	-									-	-	-	-
C1d - LCI Direct Install	Cooler Night Cover	E21C1d019	-	-									-	-	-	-
C1d - LCI Direct Install	Demand Control Ventilation	E21C1d020	-	-									-	-	-	-
C1d - LCI Direct Install	Door Heater Controls	E21C1d021	-	-									-	-	-	-
C1d - LCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C1d022	-	-									-	-	-	-
C1d - LCI Direct Install	Duct Sealing, Electric	E21C1d023	-	-									-	-	-	-
C1d - LCI Direct Install	Ductless Mini Split Heat Pump	E21C1d024	-	-									-	-	-	-
C1d - LCI Direct Install	ECM Evaporator Fan Motors for Walk-in Coole	E21C1d025	-	-									-	-	-	-
C1d - LCI Direct Install	Electronic Defrost Control	E21C1d026	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Management System, Electric	E21C1d027	-	-									-	-	-	-
C1d - LCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C1d028	-	-									-	-	-	-
C1d - LCI Direct Install	Evaporator Fan Control	E21C1d029	-	-									-	-	-	-
C1d - LCI Direct Install	Faucet Aerator, Electric	E21C1d030	-	-									-	-	-	-
C1d - LCI Direct Install	Hotel Occupancy Sensor	E21C1d031	-	-									-	-	-	-
C1d - LCI Direct Install	Low Pressure Drop Filter	E21C1d032	-	-									-	-	-	-
C1d - LCI Direct Install	Low-Flow Showerhead With Thermostatic Val	E21C1d033	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1d - LCI Direct Install	Low-Flow Showerhead, Electric	E21C1d034	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Open Drip	E21C1d035	-	-									-	-	-	-
C1d - LCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C1d036	-	-									-	-	-	-
C1d - LCI Direct Install	Novelty Cooler Shutoff	E21C1d037	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Heating, Electric	E21C1d038	-	-									-	-	-	-
C1d - LCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C1d039	-	-									-	-	-	-
C1d - LCI Direct Install	Pre Rinse Spray Valve, Electric	E21C1d040	-	-									-	-	-	-
C1d - LCI Direct Install	Programmable Thermostat, Electric	E21C1d041	-	-									-	-	-	-
C1d - LCI Direct Install	Steam Trap, Electric	E21C1d042	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive	E21C1d043	-	-									-	-	-	-
C1d - LCI Direct Install	Variable Frequency Drive with Motor	E21C1d044	-	-									-	-	-	-
C1d - LCI Direct Install	Vending Miser	E21C1d045	-	-									-	-	-	-
C1d - LCI Direct Install	Zero Loss Condensate Drain	E21C1d046	-	-									-	-	-	-
	Large Business Energy Solutions Subtotal				**2,266.5**	**2,419.2**	**28,144.5**	**29,284.3**	**427.1**	**182.8**	**353.8**	**129.1**	**(354.1)**	**(330.0)**	**(3,653.8)**	**(2,890.4)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2a - SCI Retrofit	Custom Small Compressed Air Retro	E21C2a001	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Hot Water Retro	E21C2a002	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small HVAC Retro	E21C2a003	12	14	153.9	179.6	3,847.5	4,488.8	16.6	-	13.7	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Interior	E21C2a004	20	25	474.4	559.7	4,743.7	5,596.5	31.0	64.1	40.6	84.0	(267.5)	(315.6)	(2,675.2)	(3,156.1)
C2a - SCI Retrofit	Custom Small Lighting Retro - Exterior	E21C2a047	8	10	274.2	323.5	2,467.9	2,911.5	30.5	63.0	-	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Lighting Retro - Controls	E21C2a048	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Motors Retro	E21C2a005	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Process Retro	E21C2a006	3	3	67.5	67.5	1,012.5	1,012.5	7.7	-	8.1	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Refrigeration Retro	E21C2a007	11	11	66.0	66.0	792.0	792.0	8.3	-	7.5	-	-	-	-	-
C2a - SCI Retrofit	Custom Small Other Retro	E21C2a008	9	12	219.9	293.1	2,858.1	3,810.9	24.5	-	18.7	-	-	-	-	-
C2a - SCI Retrofit	Daylight Dimming	E21C2a009	-	-									-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/ Controls	E21C2a010	100	100	18.5	17.5	185.2	174.8	3.6	3.4	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Exterior w/o Controls	E21C2a011	35	35	32.2	30.4	322.5	304.4	6.3	5.9	-	-	-	-	-	-
C2a - SCI Retrofit	Lighting Fixture - Interior w/ Controls	E21C2a012	175	175	29.9	28.2	298.9	282.1	2.2	2.1	2.8	2.7	(19.4)	(18.3)	(193.7)	(182.8)
C2a - SCI Retrofit	Lighting Fixture - Interior w/o Controls	E21C2a013	-	-									-	-	-	-
C2a - SCI Retrofit	Lighting Occupancy Sensors	E21C2a014	-	-									-	-	-	-
C2a - SCI Retrofit	Boiler Reset Controls, Electric	E21C2a015	-	-									-	-	-	-
C2a - SCI Retrofit	Case Motor Replacement	E21C2a016	-	-									-	-	-	-
C2a - SCI Retrofit	Cooler Night Cover	E21C2a017	-	-									-	-	-	-
C2a - SCI Retrofit	Demand Control Ventilation	E21C2a018	-	-									-	-	-	-
C2a - SCI Retrofit	Door Heater Controls	E21C2a019	-	-									-	-	-	-
C2a - SCI Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C2a020	6	7	12.4	14.5	124.3	145.0	-	-	0.5	-	-	-	-	-
C2a - SCI Retrofit	Duct Sealing, Electric	E21C2a021	-	-									-	-	-	-
C2a - SCI Retrofit	Ductless Mini Split Heat Pump	E21C2a022	16	16	12.1	12.1	144.8	144.8	-	-	0.5	-	-	-	-	-
C2a - SCI Retrofit	ECM Evaporator Fan Motors for Walk-in Coole	E21C2a023	-	-									-	-	-	-
C2a - SCI Retrofit	Electronic Defrost Control	E21C2a024	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Management System, Electric	E21C2a025	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Star Wifi Thermostat, Electric	E21C2a026	-	-									-	-	-	-
C2a - SCI Retrofit	Evaporator Fan Control	E21C2a027	-	-									-	-	-	-
C2a - SCI Retrofit	Faucet Aerator, Electric	E21C2a028	-	-									-	-	-	-
C2a - SCI Retrofit	Hotel Occupancy Sensor	E21C2a031	-	-									-	-	-	-
C2a - SCI Retrofit	Low Pressure Drop Filter	E21C2a032	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C2a033	-	-									-	-	-	-
C2a - SCI Retrofit	Low-Flow Showerhead, Electric	E21C2a034	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Open Drip	E21C2a035	-	-									-	-	-	-
C2a - SCI Retrofit	Motors, Totally Enclosed Fan Cooled	E21C2a036	-	-									-	-	-	-
C2a - SCI Retrofit	Novelty Cooler Shutoff	E21C2a037	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Heating, Electric	E21C2a038	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Hot Water, Electric	E21C2a039	-	-									-	-	-	-
C2a - SCI Retrofit	Pre Rinse Spray Valve, Electric	E21C2a040	-	-									-	-	-	-
C2a - SCI Retrofit	Programmable Thermostat, Electric	E21C2a041	-	-									-	-	-	-
C2a - SCI Retrofit	Steam Trap, Electric	E21C2a042	-	-									-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive	E21C2a043	5	5	7.1	7.1	106.4	106.4	1.2	-	1.1	-	-	-	-	-
C2a - SCI Retrofit	Variable Frequency Drive with Motor	E21C2a044	10	10	11.4	11.4	170.3	170.3	1.9	-	1.7	-	-	-	-	-
C2a - SCI Retrofit	Vending Miser	E21C2a045	-	-									-	-	-	-
C2a - SCI Retrofit	Zero Loss Condensate Drain	E21C2a046	-	-									-	-	-	-
C2a - SCI Retrofit	Small Retrocommissioning	E21C2a049	-	-									-	-	-	-
													-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Custom Small Compressed Air New	E21C2b001	3	3	121.5	121.5	1,579.5	1,579.5	15.4	-	15.4	-	-	-	-	-
C2b - SCI New Equipment	Custom Small Hot Water New	E21C2b002	3	3	34.2	34.2	513.0	513.0	3.5	-	1.4	-	-	-	-	-
C2b - SCI New Equipment	Custom Small HVAC New	E21C2b003	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Interior	E21C2b004	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Exterior	E21C2b054	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Lighting New - Controls	E21C2b055	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Motors New	E21C2b005	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Process New	E21C2b006	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Refrigeration New	E21C2b007	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Other New	E21C2b008	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Comprehensive Design	E21C2b056	-	-									-	-	-	-
C2b - SCI New Equipment	Daylight Dimming	E21C2b009	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/ Controls	E21C2b010	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Exterior w/o Controls	E21C2b011	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/ Controls	E21C2b012	-	-									-	-	-	-
C2b - SCI New Equipment	Performance Lighting - Interior w/o Controls	E21C2b013	-	-									-	-	-	-
C2b - SCI New Equipment	Lighting Occupancy Sensors	E21C2b014	-	-									-	-	-	-
C2b - SCI New Equipment	Advanced Power Strip	E21C2b015	-	-									-	-	-	-
C2b - SCI New Equipment	Air Compressor	E21C2b016	2	2	37.8	37.8	567.0	567.0	4.2	-	5.0	-	-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer k		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2b - SCI New Equipment	Air Nozzle	E21C2b017	-	-									-	-	-	-
C2b - SCI New Equipment	Circulator Pump	E21C2b018	-	-									-	-	-	-
C2b - SCI New Equipment	Combination Oven, Electric	E21C2b019	-	-									-	-	-	-
C2b - SCI New Equipment	Compressor Storage	E21C2b020	-	-									-	-	-	-
C2b - SCI New Equipment	Convection Oven, Electric	E21C2b021	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Door Type	E21C2b022	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Multi Tank Conveyor	E21C2b023	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Pot, Pan, Utensil	E21C2b024	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Single Tank Conveyo	E21C2b025	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - High Temp Under Counter	E21C2b026	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Door Type	E21C2b027	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Multi Tank Conveyor	E21C2b028	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Single Tank Conveyo	E21C2b029	-	-									-	-	-	-
C2b - SCI New Equipment	Dishwasher - Low Temp Under Counter	E21C2b030	-	-									-	-	-	-
C2b - SCI New Equipment	Faucet Aerator, Electric	E21C2b031	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Large Vat, Electric	E21C2b032	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer Standard Vat, Electric	E21C2b033	-	-									-	-	-	-
C2b - SCI New Equipment	Griddle, Electric	E21C2b034	-	-									-	-	-	-
C2b - SCI New Equipment	Ground Source Heat Pump	E21C2b035	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet 3/4 Size	E21C2b036	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Full Size	E21C2b037	-	-									-	-	-	-
C2b - SCI New Equipment	Hot Food Holding Cabinet Half Size	E21C2b038	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Ice Making Head	E21C2b039	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Batch	E21C2b040	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Remote Cond./Split Unit - Contin	E21C2b041	-	-									-	-	-	-
C2b - SCI New Equipment	Ice Machine - Self Contained	E21C2b042	-	-									-	-	-	-
C2b - SCI New Equipment	Low Pressure Drop Filter	E21C2b043	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead With Thermostatic Valv	E21C2b044	-	-									-	-	-	-
C2b - SCI New Equipment	Low-Flow Showerhead, Electric	E21C2b045	-	-									-	-	-	-
C2b - SCI New Equipment	Pre Rinse Spray Valve, Electric	E21C2b046	-	-									-	-	-	-
C2b - SCI New Equipment	Refrigerated Air Dryer	E21C2b047	-	-									-	-	-	-
C2b - SCI New Equipment	Steam Cooker, Electric	E21C2b048	-	-									-	-	-	-
C2b - SCI New Equipment	Unitary Air Conditioner	E21C2b049	-	-									-	-	-	-
C2b - SCI New Equipment	Water Source Heat Pump	E21C2b050	-	-									-	-	-	-
C2b - SCI New Equipment	Zero Loss Condensate Drain	E21C2b051	-	-									-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - FL	E21C2b052	-	-									-	-	-	-
C2b - SCI New Equipment	High Efficiency Chiller - IPLV	E21C2b053	-	-									-	-	-	-
C2b - SCI New Equipment	C&I Small New Construction Code Complianc	E21C2b057	-	-									-	-	-	-
													-	-	-	-
C2c - SCI Midstream	Midstream Circulator Pump	E21C2c001	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Demand Control Ventilation	E21C2c002	7	7	3.0	3.0	30.1	30.1	0.0	-	0.3	-	-	-	-	-
C2c - SCI Midstream	Midstream DMSHP Systems	E21C2c003	8	8	5.5	5.5	66.0	66.0	-	-	0.2	-	-	-	-	-
C2c - SCI Midstream	Midstream Dual Enthalpy Economizer Controls	E21C2c004	8	8	8.6	8.6	86.0	86.0	-	-	0.3	-	-	-	-	-
C2c - SCI Midstream	Midstream ECM Fan Motors	E21C2c005	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Systems	E21C2c006	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Unitary Air Conditioners	E21C2c007	6	8	19.3	25.7	231.0	308.0	-	-	0.8	-	-	-	-	-
C2c - SCI Midstream	Midstream VRF	E21C2c008	2	3	15.1	22.7	181.5	272.3	-	-	0.6	-	-	-	-	-
C2c - SCI Midstream	Midstream Water Source Heat Pump Systems	E21C2c009	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream LED Downlight	E21C2c010	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Exterior	E21C2c011	300	300	79.1	71.9	770.3	700.3	16.0	14.5	-	-	-	-	-	-
C2c - SCI Midstream	Midstream LED High Bay/Low Bay	E21C2c012	600	600	278.4	253.1	3,496.6	3,178.7	48.4	44.0	61.9	56.2	(60.4)	(54.9)	(758.3)	(689.4)
C2c - SCI Midstream	Midstream LED Linear Fixture	E21C2c013	500	500	47.3	43.0	520.1	472.8	5.4	4.9	6.9	6.3	(6.8)	(6.1)	(74.2)	(67.5)
C2c - SCI Midstream	Midstream LED Linear Fixture with Controls	E21C2c014	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Linear Lamp	E21C2c015	2,000	2,000	102.8	93.4	1,082.1	983.8	11.8	10.7	15.0	13.7	(14.7)	(13.3)	(154.5)	(140.4)
C2c - SCI Midstream	Midstream LED Screw In	E21C2c016	-	-									-	-	-	-
C2c - SCI Midstream	Midstream LED Stairwell Kit	E21C2c017	33	33	5.2	4.7	52.2	47.4	0.9	0.8	0.9	0.8	-	-	-	-
C2c - SCI Midstream	Midstream Combination Oven, Electric	E21C2c018	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Convection Oven, Electric	E21C2c019	1	-	2.4		28.8		0.5		0.5		-	-	-	-
C2c - SCI Midstream	Midstream Conveyor Broiler	E21C2c047	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Deck Oven, Electric	E21C2c050	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Door Type	E21C2c020	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Multi Tanl	E21C2c021	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Pot, Pan,	E21C2c022	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Single Ta	E21C2c023	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - High Temp Under Co	E21C2c024	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Door Type	E21C2c025	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Multi Tank	E21C2c026	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Single Tar	E21C2c027	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Dishwasher - Low Temp Under Cou	E21C2c028	1	-	1.9		18.7		0.3		0.3		-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Solid Door	E21C2c029	5	5	0.9	0.9	10.9	10.9	0.1	0.1	0.1	0.1	-	-	-	-
C2c - SCI Midstream	Midstream Freezer - Glass Door	E21C2c030	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Fryer Large Vat, Electric	E21C2c031	3	3	7.3	7.3	88.0	88.0	1.2	1.2	1.2	1.2	-	-	-	-
C2c - SCI Midstream	Midstream Fryer Standard Vat, Electric	E21C2c032	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Griddle, Electric	E21C2c033	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hand-Wrap Machine	E21C2c051	-	-									-	-	-	-
C2c - SCI Midstream	Midstream High Efficiency Condensing Unit	E21C2c052	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet 3/4 Size	E21C2c034	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Full Size	E21C2c035	2	2	4.7	4.7	56.5	56.5	0.8	0.8	0.8	0.8	-	-	-	-
C2c - SCI Midstream	Midstream Hot Food Holding Cabinet Half Size	E21C2c036	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Ice Making Head	E21C2c037	5	5	4.8	4.8	38.4	38.4	1.2	1.2	1.2	1.2	-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Un	E21C2c038	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Remote Cond/Split Un	E21C2c039	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ice Machine Self Contained	E21C2c040	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerated Chef Base	E21C2c053	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Glass Door	E21C2c041	5	5	1.1	1.1	12.6	12.6	0.1	0.1	0.1	0.1	-	-	-	-
C2c - SCI Midstream	Midstream Refrigerator - Solid Door	E21C2c042	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Steam Cooker, Electric	E21C2c043	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Ultra Low-Temp Freezer	E21C2c048	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 120 gallo	E21C2c044	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 50 gallor	E21C2c045	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Heat Pump Water Heater, 80 gallor	E21C2c046	-	-									-	-	-	-
													-	-	-	-
C2d - SCI Direct Install	Custom Small Compressed Air Direct Install	E21C2d001	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Hot Water Direct Install	E21C2d002	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small HVAC Direct Install	E21C2d003	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Interior	E21C2d004	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Exterior	E21C2d005	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Lighting Direct Install - Controls	E21C2d006	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Motors Direct Install	E21C2d007	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Process Direct Install	E21C2d008	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Refrigeration Direct Install	E21C2d009	-	-									-	-	-	-
C2d - SCI Direct Install	Custom Small Other Direct Install	E21C2d010	-	-									-	-	-	-
C2d - SCI Direct Install	Daylight Dimming	E21C2d011	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/ Controls	E21C2d012	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Exterior w/o Controls	E21C2d013	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Interior w/ Controls	E21C2d014	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Fixture - Interior w/o Controls	E21C2d015	-	-									-	-	-	-
C2d - SCI Direct Install	Lighting Occupancy Sensors	E21C2d016	-	-									-	-	-	-
C2d - SCI Direct Install	Boiler Reset Controls, Electric	E21C2d017	-	-									-	-	-	-
C2d - SCI Direct Install	Case Motor Replacement	E21C2d018	-	-									-	-	-	-
C2d - SCI Direct Install	Cooler Night Cover	E21C2d019	-	-									-	-	-	-
C2d - SCI Direct Install	Demand Control Ventilation	E21C2d020	-	-									-	-	-	-
C2d - SCI Direct Install	Door Heater Controls	E21C2d021	-	-									-	-	-	-
C2d - SCI Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C2d022	-	-									-	-	-	-
C2d - SCI Direct Install	Duct Sealing, Electric	E21C2d023	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2d - SCI Direct Install	Ductless Mini Split Heat Pump	E21C2d024	-	-									-	-	-	-
C2d - SCI Direct Install	ECM Evaporator Fan Motors for Walk-in Coole	E21C2d025	-	-									-	-	-	-
C2d - SCI Direct Install	Electronic Defrost Control	E21C2d026	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Management System, Electric	E21C2d027	-	-									-	-	-	-
C2d - SCI Direct Install	Energy Star Wifi Thermostat, Electric	E21C2d028	-	-									-	-	-	-
C2d - SCI Direct Install	Evaporator Fan Control	E21C2d029	-	-									-	-	-	-
C2d - SCI Direct Install	Faucet Aerator, Electric	E21C2d030	-	-									-	-	-	-
C2d - SCI Direct Install	Hotel Occupancy Sensor	E21C2d031	-	-									-	-	-	-
C2d - SCI Direct Install	Low Pressure Drop Filter	E21C2d032	-	-									-	-	-	-
C2d - SCI Direct Install	Low-Flow Showerhead With Thermostatic Valv	E21C2d033	-	-									-	-	-	-
C2d - SCI Direct Install	Low-Flow Showerhead, Electric	E21C2d034	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Open Drip	E21C2d035	-	-									-	-	-	-
C2d - SCI Direct Install	Motors, Totally Enclosed Fan Cooled	E21C2d036	-	-									-	-	-	-
C2d - SCI Direct Install	Novelty Cooler Shutoff	E21C2d037	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Heating, Electric	E21C2d038	-	-									-	-	-	-
C2d - SCI Direct Install	Pipe Wrap - Hot Water, Electric	E21C2d039	-	-									-	-	-	-
C2d - SCI Direct Install	Pre Rinse Spray Valve, Electric	E21C2d040	-	-									-	-	-	-
C2d - SCI Direct Install	Programmable Thermostat, Electric	E21C2d041	-	-									-	-	-	-
C2d - SCI Direct Install	Steam Trap, Electric	E21C2d042	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive	E21C2d043	-	-									-	-	-	-
C2d - SCI Direct Install	Variable Frequency Drive with Motor	E21C2d044	-	-									-	-	-	-
C2d - SCI Direct Install	Vending Miser	E21C2d045	-	-									-	-	-	-
C2d - SCI Direct Install	Zero Loss Condensate Drain	E21C2d046	-	-									-	-	-	-
	Small Business Energy Solutions Subtotal				**2,160.3**	**2,354.4**	**26,503.5**	**28,951.3**	**243.6**	**216.7**	**208.1**	**166.9**	**(368.7)**	**(408.3)**	**(3,855.9)**	**(4,236.2)**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Custom Muni Compressed Air Retro	E21C3a001	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Hot Water Retro	E21C3a002	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni HVAC Retro	E21C3a003	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Interior	E21C3a004	1	1	60.1	56.7	540.8	510.4	9.1	6.5	11.9	8.5	(33.9)	(32.0)	(305.0)	(287.8)
C3a - Muni Retrofit	Custom Muni Lighting Retro - Exterior	E21C3a091	4	5	104.5	123.2	1,044.6	1,232.4	20.3	24.0	-	-	-	-	-	-
C3a - Muni Retrofit	Custom Muni Lighting Retro - Controls	E21C3a092	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Motors Retro	E21C3a005	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Process Retro	E21C3a006	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Refrigeration Retro	E21C3a007	-	-									-	-	-	-
C3a - Muni Retrofit	Custom Muni Other Retro	E21C3a008	4	4	144.0	144.0	1,872.0	1,872.0	-	-	16.8	-	-	-	-	-
C3a - Muni Retrofit	Daylight Dimming	E21C3a009	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/ Controls	E21C3a010	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Exterior w/o Controls	E21C3a011	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Interior w/ Controls	E21C3a012	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Fixture - Interior w/o Controls	E21C3a013	-	-									-	-	-	-
C3a - Muni Retrofit	Lighting Occupancy Sensors	E21C3a014	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Electric	E21C3a015	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Gas	E21C3a016	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Oil	E21C3a017	-	-									-	-	-	-
C3a - Muni Retrofit	Air Sealing, Propane	E21C3a018	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Gas	E21C3a019	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Oil	E21C3a020	-	-									-	-	-	-
C3a - Muni Retrofit	Boiler Reset Controls, Propane	E21C3a021	-	-									-	-	-	-
C3a - Muni Retrofit	Case Motor Replacement	E21C3a022	-	-									-	-	-	-
C3a - Muni Retrofit	Cooler Night Cover	E21C3a023	-	-									-	-	-	-
C3a - Muni Retrofit	Demand Control Ventilation	E21C3a024	-	-									-	-	-	-
C3a - Muni Retrofit	Door Heater Controls	E21C3a025	-	-									-	-	-	-
C3a - Muni Retrofit	Dual Enthalpy Economizer Controls (DEEC)	E21C3a026	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Electric	E21C3a027	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Gas	E21C3a028	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Oil	E21C3a029	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Insulation, Propane	E21C3a030	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Electric	E21C3a031	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Gas	E21C3a032	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Oil	E21C3a033	-	-									-	-	-	-
C3a - Muni Retrofit	Duct Sealing, Propane	E21C3a034	-	-									-	-	-	-
C3a - Muni Retrofit	Ductless Mini Split Heat Pump	E21C3a035	-	-									-	-	-	-
C3a - Muni Retrofit	ECM Evaporator Fan Motors for Walk-in Coole	E21C3a036	-	-									-	-	-	-
C3a - Muni Retrofit	Electronic Defrost Control	E21C3a037	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Management System, Electric	E21C3a038	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Electric	E21C3a039	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Gas	E21C3a040	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Oil	E21C3a041	-	-									-	-	-	-
C3a - Muni Retrofit	Energy Star Wifi Thermostat, Propane	E21C3a042	-	-									-	-	-	-
C3a - Muni Retrofit	Evaporator Fan Control	E21C3a043	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Electric	E21C3a044	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Gas	E21C3a045	-	-									-	-	-	-
C3a - Muni Retrofit	Faucet Aerator, Oil	E21C3a046	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3a - Muni Retrofit	Faucet Aerator, Propane	E21C3a047	-	-									-	-	-	-
C3a - Muni Retrofit	Hotel Occupancy Sensor	E21C3a050	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Electric	E21C3a051	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Gas	E21C3a052	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Oil	E21C3a053	-	-									-	-	-	-
C3a - Muni Retrofit	Insulation, Propane	E21C3a054	-	-									-	-	-	-
C3a - Muni Retrofit	Low Pressure Drop Filter	E21C3a055	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C3a056	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C3a057	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C3a058	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead With Thermostatic Valv	E21C3a059	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Electric	E21C3a060	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Gas	E21C3a061	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Oil	E21C3a062	-	-									-	-	-	-
C3a - Muni Retrofit	Low-Flow Showerhead, Propane	E21C3a063	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Open Drip	E21C3a064	-	-									-	-	-	-
C3a - Muni Retrofit	Motors, Totally Enclosed Fan Cooled	E21C3a065	-	-									-	-	-	-
C3a - Muni Retrofit	Novelty Cooler Shutoff	E21C3a066	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Electric	E21C3a067	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Gas	E21C3a068	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Oil	E21C3a069	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Heating, Propane	E21C3a070	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Electric	E21C3a071	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Gas	E21C3a072	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Oil	E21C3a073	-	-									-	-	-	-
C3a - Muni Retrofit	Pipe Wrap - Hot Water, Propane	E21C3a074	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Electric	E21C3a075	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Gas	E21C3a076	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Oil	E21C3a077	-	-									-	-	-	-
C3a - Muni Retrofit	Pre Rinse Spray Valve, Propane	E21C3a078	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Electric	E21C3a079	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Gas	E21C3a080	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Oil	E21C3a081	-	-									-	-	-	-
C3a - Muni Retrofit	Programmable Thermostat, Propane	E21C3a082	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Electric	E21C3a083	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Gas	E21C3a084	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Oil	E21C3a085	-	-									-	-	-	-
C3a - Muni Retrofit	Steam Trap, Propane	E21C3a086	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive	E21C3a087	-	-									-	-	-	-
C3a - Muni Retrofit	Variable Frequency Drive with Motor	E21C3a088	-	-									-	-	-	-
C3a - Muni Retrofit	Vending Miser	E21C3a089	-	-									-	-	-	-
C3a - Muni Retrofit	Zero Loss Condensate Drain	E21C3a090	-	-									-	-	-	-
													-	-	-	-
C3b - Muni New Equipmen	Custom Muni Compressed Air New	E21C3b001	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Hot Water New	E21C3b002	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni HVAC New	E21C3b003	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Lighting New - Interior	E21C3b004	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Lighting New - Exterior	E21C3b085	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kW		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipmen	Custom Muni Lighting New - Controls	E21C3b086	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Motors New	E21C3b005	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Process New	E21C3b006	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Refrigeration New	E21C3b007	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Other New	E21C3b008	-	-									-	-	-	-
C3b - Muni New Equipmen	Custom Muni Comprehensive Design	E21C3b087	-	-									-	-	-	-
C3b - Muni New Equipmen	Daylight Dimming	E21C3b009	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Exterior w/ Controls	E21C3b010	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Exterior w/o Controls	E21C3b011	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Interior w/ Controls	E21C3b012	-	-									-	-	-	-
C3b - Muni New Equipmen	Performance Lighting - Interior w/o Controls	E21C3b013	-	-									-	-	-	-
C3b - Muni New Equipmen	Lighting Occupancy Sensors	E21C3b014	-	-									-	-	-	-
C3b - Muni New Equipmen	Advanced Power Strip	E21C3b015	-	-									-	-	-	-
C3b - Muni New Equipmen	Air Compressor	E21C3b016	-	-									-	-	-	-
C3b - Muni New Equipmen	Air Nozzle	E21C3b017	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1000 to 1700 MBH 90 AFUE, Oil	E21C3b018	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1000 to 1700 MBH 90 AFUE, Propane	E21C3b019	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1701 to 2000 MBH 85 AFUE, Oil	E21C3b020	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 1701 to 2000 MBH 90 AFUE, Propane	E21C3b021	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 301 to 499 MBH 85 AFUE, Oil	E21C3b022	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 301 to 499 MBH 90 AFUE, Propane	E21C3b023	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 500 to 999 MBH 85 AFUE, Oil	E21C3b024	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler 500 to 999 MBH 90 AFUE, Propane	E21C3b025	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 85 AFUE, Oil	E21C3b026	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 87 AFUE, Oil	E21C3b027	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 90 AFUE, Propane	E21C3b028	-	-									-	-	-	-
C3b - Muni New Equipmen	Boiler to 300 MBH 95 AFUE, Propane	E21C3b029	-	-									-	-	-	-
C3b - Muni New Equipmen	Circulator Pump	E21C3b030	-	-									-	-	-	-
C3b - Muni New Equipmen	Combination Oven, Electric	E21C3b031	-	-									-	-	-	-
C3b - Muni New Equipmen	Compressor Storage	E21C3b032	-	-									-	-	-	-
C3b - Muni New Equipmen	Condensing Unit Heater up to 300 MBH, Oil	E21C3b033	-	-									-	-	-	-
C3b - Muni New Equipmen	Condensing Unit Heater up to 300 MBH, Propa	E21C3b034	-	-									-	-	-	-
C3b - Muni New Equipmen	Convection Oven, Electric	E21C3b035	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Door Type	E21C3b036	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Multi Tank Conveyor	E21C3b037	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Pot, Pan, Utensil	E21C3b038	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Single Tank Conveyo	E21C3b039	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - High Temp Under Counter	E21C3b040	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Door Type	E21C3b041	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Multi Tank Conveyor	E21C3b042	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Single Tank Conveyo	E21C3b043	-	-									-	-	-	-
C3b - Muni New Equipmen	Dishwasher - Low Temp Under Counter	E21C3b044	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Electric	E21C3b045	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Gas	E21C3b046	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Oil	E21C3b047	-	-									-	-	-	-
C3b - Muni New Equipmen	Faucet Aerator, Propane	E21C3b048	-	-									-	-	-	-
C3b - Muni New Equipmen	Fryer Large Vat, Electric	E21C3b049	-	-									-	-	-	-
C3b - Muni New Equipmen	Fryer Standard Vat, Electric	E21C3b050	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3b - Muni New Equipmen	Furnace w/ ECM 85 AFUE up to 150 MBH, Oil	E21C3b051	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 87 AFUE up to 150 MBH, Oil	E21C3b052	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 95 AFUE up to 150 MBH, Pr	E21C3b053	-	-									-	-	-	-
C3b - Muni New Equipmen	Furnace w/ ECM 97 AFUE up to 150 MBH, Pr	E21C3b054	-	-									-	-	-	-
C3b - Muni New Equipmen	Griddle, Electric	E21C3b055	-	-									-	-	-	-
C3b - Muni New Equipmen	Ground Source Heat Pump	E21C3b056	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet 3/4 Size	E21C3b057	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet Full Size	E21C3b058	-	-									-	-	-	-
C3b - Muni New Equipmen	Hot Food Holding Cabinet Half Size	E21C3b059	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Ice Making Head	E21C3b060	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Remote Cond./Split Unit - Batch	E21C3b061	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Remote Cond./Split Unit - Contir	E21C3b062	-	-									-	-	-	-
C3b - Muni New Equipmen	Ice Machine - Self Contained	E21C3b063	-	-									-	-	-	-
C3b - Muni New Equipmen	Infrared Heater	E21C3b064	-	-									-	-	-	-
C3b - Muni New Equipmen	Low Pressure Drop Filter	E21C3b065	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Val	E21C3b066	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Val	E21C3b067	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Val	E21C3b068	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead With Thermostatic Val	E21C3b069	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Electric	E21C3b070	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Gas	E21C3b071	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Oil	E21C3b072	-	-									-	-	-	-
C3b - Muni New Equipmen	Low-Flow Showerhead, Propane	E21C3b073	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Electric	E21C3b074	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Gas	E21C3b075	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Oil	E21C3b076	-	-									-	-	-	-
C3b - Muni New Equipmen	Pre Rinse Spray Valve, Propane	E21C3b077	-	-									-	-	-	-
C3b - Muni New Equipmen	Refrigerated Air Dryer	E21C3b078	-	-									-	-	-	-
C3b - Muni New Equipmen	Steam Cooker, Electric	E21C3b079	-	-									-	-	-	-
C3b - Muni New Equipmen	Unitary Air Conditioner	E21C3b080	-	-									-	-	-	-
C3b - Muni New Equipmen	Water Source Heat Pump	E21C3b081	-	-									-	-	-	-
C3b - Muni New Equipmen	Zero Loss Condensate Drain	E21C3b082	-	-									-	-	-	-
C3b - Muni New Equipmen	High Efficiency Chiller - FL	E21C3b083	-	-									-	-	-	-
C3b - Muni New Equipmen	High Efficiency Chiller - IPLV	E21C3b084	-	-									-	-	-	-
													-	-	-	-
C3d - Muni Direct Install	Custom Muni Compressed Air Direct Install	E21C3d001	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Hot Water Direct Install	E21C3d002	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni HVAC Direct Install	E21C3d003	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Interior	E21C3d004	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Exterior	E21C3d005	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Lighting Direct Install - Controls	E21C3d006	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Motors Direct Install	E21C3d007	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Process Direct Install	E21C3d008	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Refrigeration Direct Install	E21C3d009	-	-									-	-	-	-
C3d - Muni Direct Install	Custom Muni Other Direct Install	E21C3d010	-	-									-	-	-	-
C3d - Muni Direct Install	Daylight Dimming	E21C3d011	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/ Controls	E21C3d012	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Exterior w/o Controls	E21C3d013	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Lighting Fixture - Interior w/ Controls	E21C3d014	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Fixture - Interior w/o Controls	E21C3d015	-	-									-	-	-	-
C3d - Muni Direct Install	Lighting Occupancy Sensors	E21C3d016	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Electric	E21C3d017	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Gas	E21C3d018	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Oil	E21C3d019	-	-									-	-	-	-
C3d - Muni Direct Install	Air Sealing, Propane	E21C3d020	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Gas	E21C3d021	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		nnual Net Summer kV		otal Net Annual MMBTI		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Boiler Reset Controls, Oil	E21C3d022	-	-									-	-	-	-
C3d - Muni Direct Install	Boiler Reset Controls, Propane	E21C3d023	-	-									-	-	-	-
C3d - Muni Direct Install	Case Motor Replacement	E21C3d024	-	-									-	-	-	-
C3d - Muni Direct Install	Cooler Night Cover	E21C3d025	-	-									-	-	-	-
C3d - Muni Direct Install	Demand Control Ventilation	E21C3d026	-	-									-	-	-	-
C3d - Muni Direct Install	Door Heater Controls	E21C3d027	-	-									-	-	-	-
C3d - Muni Direct Install	Dual Enthalpy Economizer Controls (DEEC)	E21C3d028	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Electric	E21C3d029	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Gas	E21C3d030	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Oil	E21C3d031	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Insulation, Propane	E21C3d032	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Electric	E21C3d033	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Gas	E21C3d034	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Oil	E21C3d035	-	-									-	-	-	-
C3d - Muni Direct Install	Duct Sealing, Propane	E21C3d036	-	-									-	-	-	-
C3d - Muni Direct Install	Ductless Mini Split Heat Pump	E21C3d037	-	-									-	-	-	-
C3d - Muni Direct Install	ECM Evaporator Fan Motors for Walk-in Coole	E21C3d038	-	-									-	-	-	-
C3d - Muni Direct Install	Electronic Defrost Control	E21C3d039	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Management System, Electric	E21C3d040	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Electric	E21C3d041	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Gas	E21C3d042	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Oil	E21C3d043	-	-									-	-	-	-
C3d - Muni Direct Install	Energy Star Wifi Thermostat, Propane	E21C3d044	-	-									-	-	-	-
C3d - Muni Direct Install	Evaporator Fan Control	E21C3d045	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Electric	E21C3d046	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Gas	E21C3d047	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Oil	E21C3d048	-	-									-	-	-	-
C3d - Muni Direct Install	Faucet Aerator, Propane	E21C3d049	-	-									-	-	-	-
C3d - Muni Direct Install	Hotel Occupancy Sensor	E21C3d050	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Electric	E21C3d051	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Gas	E21C3d052	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Oil	E21C3d053	-	-									-	-	-	-
C3d - Muni Direct Install	Insulation, Propane	E21C3d054	-	-									-	-	-	-
C3d - Muni Direct Install	Low Pressure Drop Filter	E21C3d055	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valv	E21C3d056	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valv	E21C3d057	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valv	E21C3d058	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead With Thermostatic Valv	E21C3d059	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Electric	E21C3d060	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Gas	E21C3d061	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Oil	E21C3d062	-	-									-	-	-	-
C3d - Muni Direct Install	Low-Flow Showerhead, Propane	E21C3d063	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Open Drip	E21C3d064	-	-									-	-	-	-
C3d - Muni Direct Install	Motors, Totally Enclosed Fan Cooled	E21C3d065	-	-									-	-	-	-
C3d - Muni Direct Install	Novelty Cooler Shutoff	E21C3d066	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Electric	E21C3d067	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Gas	E21C3d068	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Heating, Oil	E21C3d069	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C3d - Muni Direct Install	Pipe Wrap - Heating, Propane	E21C3d070	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Electric	E21C3d071	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Gas	E21C3d072	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Oil	E21C3d073	-	-									-	-	-	-
C3d - Muni Direct Install	Pipe Wrap - Hot Water, Propane	E21C3d074	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Electric	E21C3d075	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Gas	E21C3d076	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Oil	E21C3d077	-	-									-	-	-	-
C3d - Muni Direct Install	Pre Rinse Spray Valve, Propane	E21C3d078	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Electric	E21C3d079	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Gas	E21C3d080	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Oil	E21C3d081	-	-									-	-	-	-
C3d - Muni Direct Install	Programmable Thermostat, Propane	E21C3d082	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Electric	E21C3d083	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Gas	E21C3d084	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Oil	E21C3d085	-	-									-	-	-	-
C3d - Muni Direct Install	Steam Trap, Propane	E21C3d086	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive	E21C3d087	-	-									-	-	-	-
C3d - Muni Direct Install	Variable Frequency Drive with Motor	E21C3d088	-	-									-	-	-	-
C3d - Muni Direct Install	Vending Miser	E21C3d089	-	-									-	-	-	-
C3d - Muni Direct Install	Zero Loss Condensate Drain	E21C3d090	-	-									-	-	-	-
	Municipal Energy Solutions Subtotal				**308.5**	**324.0**	**3,457.4**	**3,614.8**	**29.4**	**30.5**	**28.7**	**8.5**	**(33.9)**	**(32.0)**	**(305.0)**	**(287.8)**

Unitil Energy Systems, Inc.
System Benefits Charge Calculation (LBR Component)
Effective May 1, 2022

Year	Forecasted May 1, 2022 Dec 31, 2022 LBR Revenue	Forecasted April 30, 2022 Deferral with Interest	Forecasted May 1, 2022 Dec 31, 2022 Interest	Total LBR Revenue	Forecasted May 1, 2022 Dec 31, 2022 Distribution (kWh	May 1, 2022 SBC Rate LBR Portion ($/kWh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
2022	$ -	$ 20,982	$ 226	$ 21,208	714,183,874	$ 0.00003

Col. A: Year
Col. B: Page 3, Line 2, Col. F to Col. M
Col. C: Page 3, Line 9, Col. E
Col. D: Page 3, Line 8, Col. F to Col. M
Col. E: Col. B + Col. C + Col. D
Col. F: Page 3, Line 12, Col. F to Col. M
Col. G: Col. E/Col. F

Unitil Energy System, Inc.
Monthly and Cumulative Savings and Lost Base Revenue
January 1, 2021 to December 31, 2021

Line	Description	Actual 12/31/2020	Estimate Jan-21	Estimate Feb-21	Estimate Mar-21	Estimate Apr-21	Estimate May-21	Estimate Jun-21	Estimate Jul-21	Estimate Aug-21	Estimate Sep-21	Estimate Oct-21	Estimate Nov-21	Estimate Dec-21	2021 Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized kWh Savings (2017)	1,344,216	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Residential Annualized kWh Savings (2018)	2,482,564	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Residential Annualized kWh Savings (2019)	4,692,054	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Residential Annualized kWh Savings (2020)	5,744,122	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Residential Annualized kWh Savings (2021) - Estimate	-	531,568	661,174	535,860	595,451	365,754	596,260	563,426	294,382	402,163	352,293	141,191	60,217	5,099,739
			Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	LBR Savings
6	Monthly Residential kWh Savings (2017 - 2019)	709,903	709,903	709,903	709,903	709,903	709,903	-	-	-	-	-	-	-	3,549,514
7	Average Residential Distribution Rate		0.03558	0.03558	0.03558	0.03558	0.03558	-	-	-	-	-	-	-	
8	Lost Residential Revenue		$ 25,258	$ 25,258	$ 25,258	$ 25,258	$ 25,258	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 126,292
9	Monthly Residential kWh Savings (2020)*	478,677	478,677	478,677	478,677	478,677	478,677	208,221	208,221	208,221	208,221	208,221	208,221	208,221	3,850,931
10	Average Residential Distribution Rate		0.03558	0.03558	0.03558	0.03558	0.03558	0.03942	0.03942	0.03942	0.03942	0.03942	0.03942	0.03942	
11	Lost Residential Revenue		$ 17,031	$ 17,031	$ 17,031	$ 17,031	$ 17,031	$ 8,208	$ 8,208	$ 8,208	$ 8,208	$ 8,208	$ 8,208	$ 8,208	$ 142,613
12	Monthly Residential kWh Savings		44,297	55,098	44,655	49,621	30,479	49,688	46,952	24,532	33,514	29,358	11,766	5,018	424,978
13	Cumulative Residential kWh Savings (2021)	-	44,297	99,395	144,050	193,671	224,151	273,839	320,791	345,323	378,837	408,194	419,960	424,978	3,277,487
14	Average Residential Distribution Rate		0.03558	0.03558	0.03558	0.03558	0.03558	0.03942	0.03942	0.03942	0.03942	0.03942	0.03942	0.03942	
15	Lost Residential Revenue		$ 1,576	$ 3,536	$ 5,125	$ 6,891	$ 7,975	$ 10,795	$ 12,646	$ 13,613	$ 14,934	$ 16,091	$ 16,555	$ 16,753	$ 126,489
16	**Total Residential Lost Revenue**		**$ 43,866**	**$ 45,826**	**$ 47,415**	**$ 49,180**	**$ 50,265**	**$ 19,003**	**$ 20,854**	**$ 21,821**	**$ 23,142**	**$ 24,299**	**$ 24,763**	**$ 24,961**	**395,394**

*Effective June 1, 2021, 2020 savings adjusted savings reflected in the test year

Line	Description	Actual 12/31/2020	Estimate Jan-21	Estimate Feb-21	Estimate Mar-21	Estimate Apr-21	Estimate May-21	Estimate Jun-21	Estimate Jul-21	Estimate Aug-21	Estimate Sep-21	Estimate Oct-21	Estimate Nov-21	Estimate Dec-21	2021 Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
17	C&I Annualized kWh Savings (2017)	6,004,884	-	-	-	-	-	-	-	-	-	-	-	-	-
18	C&I Annualized kWh Savings (2018)	6,708,144	-	-	-	-	-	-	-	-	-	-	-	-	-
19	C&I Annualized kWh Savings (2019)	6,410,154	-	-	-	-	-	-	-	-	-	-	-	-	-
20	C&I Annualized kWh Savings (2020)	9,599,726	-	-	-	-	-	-	-	-	-	-	-	-	-
21	C&I Annualized kWh Savings (2021) - Estimate	-	3,482	49,436	131,730	271,978	470,805	491,211	640,057	797,398	655,149	870,904	1,236,292	2,500,027	8,118,467
22	C&I Monthly kW Savings (2019)	1,139													
23	C&I Monthly kW Savings (2020)	1,211													
24	C&I Monthly kW Savings (2021) - Estimate	-	5	9	34	74	48	53	147	69	121	202	275	583	1,619
			Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	LBR Savings
25	Monthly C&I Savings (2017 & 2018)	1,059,419	1,059,419	1,059,419	1,059,419	1,059,419	1,059,419	-	-	-	-	-	-	-	
26	Average C&I Distribution Rate		0.03169	0.03169	0.03169	0.03169	0.03169	-	-	-	-	-	-	-	
27	Lost C&I Revenue		$ 33,573	$ 33,573	$ 33,573	$ 33,573	$ 33,573	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 167,865
28	Monthly C&I Savings (2019)	534,180	534,180	534,180	534,180	534,180	534,180	-	-	-	-	-	-	-	
29	Average C&I Distribution Rate		0.00031	0.00031	0.00031	0.00031	0.00031	-	-	-	-	-	-	-	
30	Lost C&I Revenue		$ 166	$ 166	$ 166	$ 166	$ 166	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 828
31	Monthly C&I Savings (2020)*	799,977	799,977	799,977	799,977	799,977	799,977	559,169	559,169	559,169	559,169	559,169	559,169	559,169	
32	Average C&I Distribution Rate		0.00031	0.00031	0.00031	0.00031	0.00031	0.00401	0.00401	0.00401	0.00401	0.00401	0.00401	0.00401	
33	Lost C&I Revenue		$ 248	$ 248	$ 248	$ 248	$ 248	$ 2,242	$ 2,242	$ 2,242	$ 2,242	$ 2,242	$ 2,242	$ 2,242	$ 16,936
34	Monthly C&I kWh Savings		290.14	4,120	10,977	22,665	39,234	40,934	53,338	66,450	54,596	72,575	103,024	208,336	
35	Cumulative C&I kWh Savings (2021)	-	290	4,410	15,387	38,052	77,286	118,220	171,558	238,008	292,604	365,179	468,203	676,539	2,465,736
36	Average C&I Distribution Rate		0.00031	0.00031	0.00031	0.00031	0.00031	0.00401	0.00401	0.00401	0.00401	0.00401	0.00401	0.00401	
37	Lost C&I Revenue		$ 0	$ 1	$ 5	$ 12	$ 24	$ 474	$ 688	$ 954	$ 1,173	$ 1,464	$ 1,877	$ 2,713	$ 9,387
38	Cumulative C&I kW Savings (2019)	1,139	1,139	1,139	1,139	1,139	1,139	0	0	0	0	0	0	0	
39	Average C&I Demand Rate		$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
40	Lost C&I Demand Revenue		$ 10,388	$ 10,388	$ 10,388	$ 10,388	$ 10,388	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,938
41	Cumulative C&I kW Savings (2020)*	1,211	1,211	1,211	1,211	1,211	1,211	849	849	849	849	849	849	849	
42	Average C&I Demand Rate		$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	
43	Lost C&I Demand Revenue		$ 11,049	$ 11,049	$ 11,049	$ 11,049	$ 11,049	$ 7,781	$ 7,781	$ 7,781	$ 7,781	$ 7,781	$ 7,781	$ 7,781	$ 109,709
44	Monthly C&I kW Savings (2021)		5	9	34	74	48	53	147	69	121	202	275	583	
45	Cumulative C&I kW Savings	-	5	14	48	122	170	223	370	439	559	761	1,036	1,619	
46	Average C&I Demand Rate		$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	$ 9.17	
47	Lost C&I Demand Revenue		$ 41	$ 124	$ 436	$ 1,110	$ 1,548	$ 2,044	$ 3,395	$ 4,024	$ 5,130	$ 6,981	$ 9,501	$ 14,847	$ 49,182
48	**Total C&I Lost Revenue**		**$ 55,464**	**$ 55,549**	**$ 55,864**	**$ 56,545**	**$ 56,995**	**$ 12,541**	**$ 14,106**	**$ 15,001**	**$ 16,326**	**$ 18,468**	**$ 21,402**	**$ 27,583**	**405,845**
49	**Total Lost Revenue**		**$ 99,330**	**$ 101,375**	**$ 103,279**	**$ 105,725**	**$ 107,260**	**$ 31,544**	**$ 34,960**	**$ 36,822**	**$ 39,468**	**$ 42,767**	**$ 46,164**	**$ 52,544**	**801,239**

*Effective June 1, 2021, 2020 savings adjusted savings reflected in the test year

Unitil Energy System, Inc.
Monthly and Cumulative Savings and Lost Base Revenue
January 1, 2022 to December 31, 2022

Line	Description	Estimate 12/31/2021	Estimate Jan-22	Estimate Feb-22	Estimate Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022 Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized kWh Savings (2020)*	2,498,651	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Residential Annualized kWh Savings (2021) - Estimate	5,099,739	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Residential Annualized kWh Savings (2022) - Estimate	-	531,568	661,174	535,860	-	-	-	-	-	-	-	-	-	1,728,602
			Jan-22	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**LBR Savings**
4	Monthly Residential kWh Savings (2020)	208,221	208,221	208,221	208,221	-	-	-	-	-	-	-	-	-	624,663
5	Average Residential Distribution Rate		0.03942	0.03942	0.03942	-	-	-	-	-	-	-	-	-	
6	Lost Residential Revenue		$ 8,208	$ 8,208	$ 8,208	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,624
7	Monthly Residential kWh Savings (2021)	424,978	424,978	424,978	424,978	-	-	-	-	-	-	-	-	-	1,274,935
8	Average Residential Distribution Rate		0.03942	0.03942	0.03942	-	-	-	-	-	-	-	-	-	
9	Lost Residential Revenue		$ 16,753	$ 16,753	$ 16,753	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,258
7	Monthly Residential kWh Savings		44,297	55,098	44,655	-	-	-	-	-	-	-	-	-	144,050
8	Cumulative Residential kWh Savings (2022)	-	44,297	99,395	144,050	-	-	-	-	-	-	-	-	-	287,743
9	Average Residential Distribution Rate		0.03942	0.03942	0.03942	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Lost Residential Revenue		$ 1,746	$ 3,918	$ 5,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,343
11	**Total Residential Lost Revenue**		**$ 26,707**	**$ 28,879**	**$ 30,639**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 86,225**

*Adjusted for savings reflected in the test year

Line	Description	Estimate 12/31/2021	Estimate Jan-22	Estimate Feb-22	Estimate Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022 Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
12	C&I Annualized kWh Savings (2020)*	9,599,726	-	-	-	-	-	-	-	-	-	-	-	-	-
13	C&I Annualized kWh Savings (2021) - Estimate	8,118,467	-	-	-	-	-	-	-	-	-	-	-	-	-
14	C&I Annualized kWh Savings (2022) - Estimate	-	3,482	49,436	131,730	-	-	-	-	-	-	-	-	-	184,647
15	C&I Monthly kW Savings (2020)*	1,211	-												
16	C&I Monthly kW Savings (2021) - Estimate	849	-	-	-	-	-	-	-	-	-	-	-	-	-
17	C&I Monthly kW Savings (2022) - Estimate	-	38	38	38	-	-	-	-	-	-	-	-	-	450
			Jan-22	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**LBR Savings**
18	Monthly C&I Savings (2020)	559,169	559,169	559,169	559,169	-	-	-	-	-	-	-	-	-	
19	Average C&I Distribution Rate		0.00401	0.00401	0.00401	-	-	-	-	-	-	-	-	-	
20	Lost C&I Revenue		$ 2,242	$ 2,242	$ 2,242	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,727
21	Monthly C&I kWh Savings (2021)	676,539	676,539	676,539	676,539	-	-	-	-	-	-	-	-	-	
22	Average C&I Distribution kWh Rate		0.00401	0.00401	0.00401	-	-	-	-	-	-	-	-	-	
23	Lost C&I Revenue		$ 2,713	$ 2,713	$ 2,713	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,139
24	Monthly C&I kWh Savings		290	4,120	10,977	-	-	-	-	-	-	-	-	-	
25	Monthly C&I kWh Savings (2022)	-	290	4,410	15,387	-	-	-	-	-	-	-	-	-	20,087
26	Average C&I Distribution kWh Rate		0.00401	0.00401	0.00401	-	-	-	-	-	-	-	-	-	
27	Lost C&I Revenue		$ 1	$ 18	$ 62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 81
28	Cumulative C&I kW Savings (2020)	849	849	849	849	-	-	-	-	-	-	-	-	-	
29	Average C&I Demand Rate		$ 9.17	$ 9.17	$ 9.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
30	Lost C&I Demand Revenue		$ 7,781	$ 7,781	$ 7,781	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,342
31	Cumulative C&I kW Savings (2021)	1,619	1,619	1,619	1,619	-	-	-	-	-	-	-	-	-	
32	Average C&I Demand Rate		$ 9.17	$ 9.17	$ 9.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
33	Lost C&I Demand Revenue		$ 14,847	$ 14,847	$ 14,847	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,542
34	Monthly C&I kW Savings (2022)		38	38	38	-	-	-	-	-	-	-	-	-	
35	Cumulative C&I kW Savings	-	38	75	113	-	-	-	-	-	-	-	-	-	
36	Average C&I Demand Rate		$ 9.17	$ 9.17	$ 9.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
37	Lost C&I Demand Revenue		$ 344	$ 688	$ 1,032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,063
38	**Total C&I Lost Revenue**		**$ 27,928**	**$ 28,289**	**$ 28,677**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**84,894**
39	**Total Lost Revenue**		**$ 54,635**	**$ 57,168**	**$ 59,316**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**171,119**

*Adjusted for savings reflected in the test year

Unitil Energy System, Inc.
Lost Base Revenue Reconciliation
January 1, 2021 to December 31, 2021

Line	Description	Actual Jan-21 Col. B	Actual Feb-21 Col. C	Actual Mar-21 Col. D	Actual Apr-21 Col. E	Actual May-21 Col. F	Actual Jun-21 Col. G	Actual Jul-21 Col. H	Actual Aug-21 Col. I	Actual Sep-21 Col. J	Actual Oct-21 Col. K	Actual Nov-21 Col. L	Actual Dec-21 Col. M	2021 Total Col. N
Total														
1	Beginning Balance	$ 204,234	$ 229,514	$ 256,878	$ 283,626	$ 327,832	$ 373,335	$ 330,810	$ 283,580	$ 236,906	$ 194,084	$ 173,162	$ 158,030	
2	Lost Revenues	$ 99,330	$ 101,375	$ 103,279	$ 105,725	$ 107,260	$ 31,544	$ 34,960	$ 36,822	$ 39,468	$ 42,767	$ 46,164	$ 52,544	$ 801,239
	REVENUE													
3	Revenue ($)	$ 74,647	$ 74,617	$ 77,275	$ 62,335	$ 62,724	$ 75,009	$ 83,037	$ 84,213	$ 82,865	$ 64,196	$ 61,737	$ 72,603	$ 875,257
4	Cumulative (Over)/Under Recovery	$ 228,917	$ 256,273	$ 282,881	$ 327,017	$ 372,369	$ 329,871	$ 282,733	$ 236,189	$ 193,510	$ 172,655	$ 157,589	$ 137,972	
	INTEREST													
5	Average Monthly Balance	$ 216,575	$ 242,894	$ 269,880	$ 305,322	$ 350,101	$ 351,603	$ 306,772	$ 259,885	$ 215,208	$ 183,370	$ 165,375	$ 148,001	
6	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7	Days per Month	31	28	31	30	31	30	31	31	30	31	30	31	365
8	Computed Interest	$ 598	$ 606	$ 745	$ 816	$ 966	$ 939	$ 847	$ 717	$ 575	$ 506	$ 442	$ 409	$ 8,165
9	**Ending Balance (Over)/Under Recovery**	$ 229,514	$ 256,878	$ 283,626	$ 327,832	$ 373,335	$ 330,810	$ 283,580	$ 236,906	$ 194,084	$ 173,162	$ 158,030	$ 138,380	

Line 1: Prior period ending balance (2020 EE Annual Report Filing June 1, 2021)
Line 2: Page 4, Line 49
Line 3: Actual revenue
Line 4: Line 1 + Line 2 - Line 3
Line 5: (Line 1 + Line 4)/2
Line 6: Prime Rate
Line 8: Line 7 * ((Line 5/# days per year) * Line 9))
Line 9: Line 4 + Line 8

Unitil Energy System, Inc.
Lost Base Revenue Reconciliation
January 1, 2022 to December 31, 2022

Line	Description	Estimate Jan-22	Estimate Feb-22	Estimate Mar-22	Estimate Apr-22	Estimate May-22	Estimate Jun-22	Estimate Jul-22	Estimate Aug-22	Estimate Sep-22	Estimate Oct-22	Estimate Nov-22	Estimate Dec-22	2022 Total
Total		Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
1	Beginning Balance	$ 138,380	$ 113,570	$ 95,270	$ 82,994	$ 20,982	$ 18,682	$ 16,079	$ 13,192	$ 10,046	$ 7,195	$ 4,922	$ 2,513	
2	Lost Revenues	$ 54,635	$ 57,168	$ 59,316	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 171,119
	REVENUE													
3	Revenue ($)	$ 79,792	$ 75,728	$ 71,837	$ 62,151	$ 2,355	$ 2,649	$ 2,928	$ 3,177	$ 2,875	$ 2,290	$ 2,419	$ 2,733	$ 310,934
4	Cumulative (Over)/Under Recovery	$ 113,223	$ 95,010	$ 82,748	$ 20,843	$ 18,627	$ 16,033	$ 13,151	$ 10,014	$ 7,172	$ 4,905	$ 2,503	$ (221)	
	INTEREST													
5	Average Monthly Balance	$ 125,802	$ 104,290	$ 89,009	$ 51,919	$ 19,805	$ 17,358	$ 14,615	$ 11,603	$ 8,609	$ 6,050	$ 3,712	$ 1,146	
6	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7	Days per Month	31	28	31	30	31	30	31	31	30	31	30	31	365
8	Computed Interest	$ 347	$ 260	$ 246	$ 139	$ 55	$ 46	$ 40	$ 32	$ 23	$ 17	$ 10	$ 3	$ 1,218
9	**Ending Balance (Over)/Under Recovery**	$ 113,570	$ 95,270	$ 82,994	$ 20,982	$ 18,682	$ 16,079	$ 13,192	$ 10,046	$ 7,195	$ 4,922	$ 2,513	$ (217)	
10	Class Sales (Residential inc. LI) -- kWh		44,974,274	40,391,317	38,722,142	34,128,082	34,411,248	44,563,884	51,023,852	39,606,404	32,448,335	35,960,935	40,740,854	
11	Class Sales (C&I) -- kWh		57,361,500	56,685,607	45,265,444	44,359,715	53,888,841	53,039,214	54,887,862	56,213,703	43,874,345	44,670,644	50,365,956	
12	Total Class Sales - kWh		102,335,774	97,076,924	83,987,586	78,487,797	88,300,089	97,603,098	105,911,714	95,820,107	76,322,680	80,631,579	91,106,810	
13	LBR SBC Rate (cents/kWh)		0.00074	0.00074	0.00074	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	

Line 1: Prior period ending balance
Line 2: Page 5, Line 39
Line 3: Estimated revenue
Line 4: Line 1 + Line 2 - Line 3
Line 5: (Line 1 + Line 4)/2
Line 6: Prime Rate
Line 8: Line 7 * ((Line 5/# days per year) * Line 9))
Line 9: Line 4 + Line 8
Line 10: Forecated Sales
Line 11: Forecated Sales
Line 12: Line 10 + Line 11

Unitil Energy System, Inc.
2020 Residential Installed kWh Savings
Savings Annualization

Line	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly Residential kWh Savings**	**134,045**	**243,706**	**882,553**	**402,367**	**529,210**	**722,187**	**561,503**	**1,094,035**	**631,791**	**468,711**	**74,014**	**-**	**5,744,122**
2														
3	**Monthly Residential Annualized kWh Savings**													
4	January 2020	11,170.45	11,170	11,170	11,170	11,170	11,170	11,170	11,170	11,170	11,170	11,170	11,170	134,045
5	February 2020		20,309	20,309	20,309	20,309	20,309	20,309	20,309	20,309	20,309	20,309	20,309	223,397
6	March 2020			73,546	73,546	73,546	73,546	73,546	73,546	73,546	73,546	73,546	73,546	735,461
7	April 2020				33,531	33,531	33,531	33,531	33,531	33,531	33,531	33,531	33,531	301,775
8	May 2020					44,101	44,101	44,101	44,101	44,101	44,101	44,101	44,101	352,806
9	June 2020						60,182	60,182	60,182	60,182	60,182	60,182	60,182	421,276
10	July 2020							46,792	46,792	46,792	46,792	46,792	46,792	280,751
11	August 2020								91,170	91,170	91,170	91,170	91,170	455,848
12	September 2020									52,649	52,649	52,649	52,649	210,597
13	October 2020										39,059	39,059	39,059	117,178
14	November 2020											6,168	6,168	12,336
15	December 2020												-	-
16	**Total 2020 Savings Realized in 2020**	**11,170**	**31,479**	**105,025**	**138,556**	**182,657**	**242,839**	**289,631**	**380,800**	**433,450**	**472,509**	**478,677**	**478,677**	**3,245,471**
17														
18	**2020 Residential kWh Savings Realized in 2021**	**-**	**20,309**	**147,092**	**100,592**	**176,403**	**300,911**	**280,751**	**638,187**	**421,194**	**351,533**	**61,678**	**-**	**2,498,651**

Unitil Energy System, Inc.
2020 C&I Installed kWh & kW Savings
Savings Annualization

Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly C&I kWh Savings**	**-**	**194,934**	**381,074**	**62,671**	**625,073**	**258,137**	**1,288,070**	**298,718**	**699,666**	**1,025,837**	**1,485,978**	**3,279,567**	**9,599,726**
2														
3	**Monthly C&I Annualized kWh Savings**													
4	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
5	February 2020		16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	178,690
6	March 2020			31,756	31,756	31,756	31,756	31,756	31,756	31,756	31,756	31,756	31,756	317,561
7	April 2020				5,223	5,223	5,223	5,223	5,223	5,223	5,223	5,223	5,223	47,003
8	May 2020					52,089	52,089	52,089	52,089	52,089	52,089	52,089	52,089	416,715
9	June 2020						21,511	21,511	21,511	21,511	21,511	21,511	21,511	150,580
10	July 2020							107,339	107,339	107,339	107,339	107,339	107,339	644,035
11	August 2020								24,893	24,893	24,893	24,893	24,893	124,466
12	September 2020									58,306	58,306	58,306	58,306	233,222
13	October 2020										85,486	85,486	85,486	256,459
14	November 2020											123,832	123,832	247,663
15	December 2020												273,297	273,297
16	**Total 2020 kWh C&I Savings Realized in 2020**	**-**	**16,245**	**48,001**	**53,223**	**105,313**	**126,824**	**234,163**	**259,056**	**317,362**	**402,848**	**526,680**	**799,977**	**2,889,692**
17														
18	**2020 C&I kWh Savings Realized in 2021**	**-**	**16,245**	**63,512**	**15,668**	**208,358**	**107,557**	**644,035**	**174,252**	**466,444**	**769,378**	**1,238,315**	**3,006,270**	**6,710,034**
19														
20														
21	**C&I Monthly kW 2020 Savings**	**-**	**29**	**47**	**8**	**60**	**50**	**154**	**20**	**99**	**136**	**219**	**388**	**1,211**
22														
23	**Monthly C&I Annualized kW Savings**		1	2	3	4	5	6	7	8	9	10	11	
24	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
25	February 2020		29	29	29	29	29	29	29	29	29	29	29	323
26	March 2020			47	47	47	47	47	47	47	47	47	47	472
27	April 2020				8	8	8	8	8	8	8	8	8	76
28	May 2020					60	60	60	60	60	60	60	60	481
29	June 2020						50	50	50	50	50	50	50	348
30	July 2020							154	154	154	154	154	154	925
31	August 2020								20	20	20	20	20	98
32	September 2020									99	99	99	99	397
33	October 2020										136	136	136	409
34	November 2020											219	219	437
35	December 2020												388	388
36	**Total 2020 kW C&I Savings Realized in 2020**	**-**	**29**	**77**	**85**	**145**	**195**	**349**	**369**	**468**	**604**	**823**	**1,211**	**4,356**
37														
38	**2020 C&I kW Savings Realized in 2021**	**-**	**29**	**94**	**25**	**241**	**249**	**925**	**137**	**793**	**1,228**	**2,186**	**4,273**	**10,182.09**

Unitil Energy Systems, Inc.
Calculation of Average Distribution Rate for Lost Revenue
Based on Actual Billing Determinants for January - May 2021 and Effective Distribution Rates*

	Rate Class	(1) Revenue Demand Charges	(2) Revenue kWh Charges	(3) = (1) + (2) Revenue Total Demand and kWh Charges	(4) Delivery kW	(5) Delivery kWh	(6) = (1) / (4) Average Distribution Rate $/kW	(7) = (2) / (5) Average Distribution Rate $/kWh[(a)]	(8) = (3) / (4) Average Distribution Rate $/kWh[(b)]
1	**Residential D**	$ -	$ 7,513,107	$ 7,513,107	-	211,160,962	**N/A**	**N/A**	**$ 0.03558**
2	Regular General G2	$ 5,182,543	$ 80,208	$ 5,262,751	493,884	130,987,963	$ 10.49	$ 0.00061	$ 0.04018
3	Large General Service Rate G1	$ 2,986,600	$ -	$ 2,986,600	401,418	129,346,653	$ 7.44	$ -	$ 0.02309
4	**Commercial and Industrial**	$ 8,169,143	$ 80,208	$ 8,249,351	895,302	260,334,616	**$ 9.12**	**$ 0.00031**	**$ 0.03169**

Note: See page 6 for details.
* Revenues include demand charges and kWh charges only.
Customer, meter and per luminaire charges are excluded.
(a) For 2019, 2020 and 2021 C&I Savings.
(b) For 2017 and 2018 C&I Savings (in 2020 calculation).

Unitil Energy Systems, Inc.
Calculation of Average Distribution Rate for Lost Revenue
Based on Actual Billing Determinants for June - December 2021 and Effective Distribution Rates*

	Rate Class	(1) Revenue: Demand Charges	(2) Revenue: kWh Charges	(3) = (1) + (2) Revenue: Total Demand and kWh Charges	(4) Delivery kW	(5) Delivery kWh	(6) = (1) / (4) Average Distribution Rate $/kW	(7) = (2) / (5) Average Distribution Rate $/kWh[(a)]	(8) = (3) / (4) Average Distribution Rate $/kWh[(b)]
1	**Residential D**	$ -	$ 12,154,959	$ 12,154,959	-	308,344,971	**N/A**	**N/A**	**$ 0.03942**
2	Regular General G2	$ 8,288,890	$ 814,298	$ 9,103,188	789,800	195,028,650	$ 10.49	$ 0.00418	$ 0.04668
3	Large General Service Rate G1	$ 4,497,352	$ 763,639	$ 5,260,991	604,403	198,864,288	$ 7.44	$ 0.00384	$ 0.02646
4	**Commercial and Industrial**	$ 12,786,242	$ 1,577,937	$ 14,364,179	1,394,202	393,892,938	**$ 9.17**	**$ 0.00401**	**$ 0.03647**

Note: See page 6 for details.
* Revenues include demand charges and kWh charges only.
Customer, meter and per luminaire charges are excluded.
(a) For 2019, 2020 and 2021 C&I Savings.
(b) For 2017 and 2018 C&I Savings (in 2020 calculation).

Unitil Energy Systems, Inc.
Calculation of Distribution Revenue at the Rate Level Effective January 1, 2021 - May 31, 2021
Based on Billing Determinants for January through May 2021

Rate Class	Customer Group		(a) 1/1/2021 Monthly Distribution Charge (1)	(b) Jan - May Billing Determinants (2)	(c) Calculated Revenue = (a) X (b): Customer/ Meter/ Luminaire	Demand	kWh	Total
Residential Rate R	Standard Rate	Customer Charge	$ 16.22	339,194	$ 5,501,724			
		All kWh	$ 0.03558	211,160,962			$ 7,513,107	$ 13,014,831
Total Rate R		**Customers**		**339,194**				
		Meters		**n/a**				
		KWH		**211,160,962**				
		Revenue			**$ 5,501,724**	**$ -**	**$ 7,513,107**	**$ 13,014,831**
General Rate G2	Standard Rate	Customer Charge	$ 29.19	52,700	$ 1,538,302			
		Demand charge (All KW)	$ 10.51	493,884		$ 5,190,717		
		All KWH	$ -	128,342,376			$ -	
		Transformer Ownership Credit, G2	$ (0.50000)	16,347		$ (8,174)		$ 6,729,019
	G2 - kWh Meter	Customer Charge	$ 18.38	1,857	$ 34,130			
		All KWH	$ 0.00883	196,338			$ 1,734	$ 35,864
	QR Water Heating and/or Space Heat	Customer Charge	$ 9.73	1,259	$ 12,250			
		All KWH	$ 0.03204	2,449,249			$ 78,474	$ 90,724
Total Rate G2		**Customers**		**55,816**				
		Meters		**n/a**				
		Billing demand		**493,884**				
		KWH		**130,987,963**				
		Revenue			**$ 1,584,683**	**$ 5,182,543**	**$ 80,208**	**$ 6,855,607**
Large General Rate G1	Standard Rate	Customer Charge Secondary Voltage	$ 162.18	77	$ 12,456			
		Customer Charge Primary Voltage	$ 86.49	1,260	$ 108,985			
		All kVA	$ 7.60	401,418		$ 3,050,778		
		All KWH	$ -	129,346,653			$ -	
		Transformer Ownership Credit, G1	$ (0.50000)	128,356		$ (64,178)		$ 3,108,042
Total Rate G1		**Customers Secondary Voltage**		**77**				
		Customers Primary Voltage		**1,260**				
		Meters		**n/a**				
		Billing demand		**401,418**				
		KWH		**129,346,653**				
		Revenue			**$ 121,441**	**$ 2,986,600**	**$ -**	**$ 3,108,042**

Outdoor Lighting Rate OL	100W Mercury Vapor Street	$13.28	13,919	$ 184,842			
	175W Mercury Vapor Street	$15.75	793	$ 12,493			
	250W Mercury Vapor Street	$17.85	771	$ 13,754			
	400W Mercury Vapor Street	$21.25	1,298	$ 27,584			
	1000W Mercury Vapor Street	$42.19	24	$ 1,013			
	250W Mercury Vapor Flood	$19.02	665	$ 12,652			
	400W Mercury Vapor Flood	$22.75	901	$ 20,505			
	1000W Mercury Vapor Flood	$37.70	144	$ 5,429			
	100W Mercury Vapor Power Bracket	$13.41	3,894	$ 52,213			
	175W Mercury Vapor Power Bracket	$14.87	557	$ 8,277			
	50W Sodium Vapor Street	$13.52	35,908	$ 485,479			
	100W Sodium Vapor Street	$15.22	1,309	$ 19,930			
	150W Sodium Vapor Street	$15.28	3,906	$ 59,691			
	250W Sodium Vapor Street	$19.14	12,893	$ 246,776			
	400W Sodium Vapor Street	$24.13	2,711	$ 65,421			
	1000W Sodium Vapor Street	$41.66	1,606	$ 66,885			
	150W Sodium Vapor Flood	$17.61	2,690	$ 47,379			
	250W Sodium Vapor Flood	$20.76	3,790	$ 78,671			
	400W Sodium Vapor Flood	$23.58	4,857	$ 114,525			
	1000W Sodium Vapor Flood	$42.03	2,467	$ 103,675			
	50W Sodium Vapor Power Bracket	$12.51	1,387	$ 17,355			
	100W Sodium Vapor Power Bracket	$14.04	904	$ 12,691			
	175W Metal Halide Street	$19.91	1	$ 20			
	250W Metal Halide Street	$21.65	-	$ -			
	400W Metal Halide Street	$22.45	-	$ -			
	175W Metal Halide Flood	$23.00	-	$ -			
	250W Metal Halide Flood	$24.83	-	$ -			
	400W Metal Halide Flood	$24.88	-	$ -			
	175W Metal Halide Power Bracket	$32.22	535	$ 17,222			
	250W Metal Halide Power Bracket	$18.63	-	$ -			
	400W Metal Halide Power Bracket	$19.81	-	$ -			
	1000W Metal Halide Flood (Contracts)	$21.17	-	$ -			
	42W 3780 K LED Area Light Fixture	$13.16	-	$ -			
	57W 5130K LED Area Light Fixture	$13.21	-	$ -			
	25W 2500K LED Cobra Head Fixture	$13.11	-	$ -			
	88W 8800K LED Cobra Head Fixture	$13.30	-	$ -			
	108W 10800K LED Cobra Head Fixture	$13.36	-	$ -			
	193W 19300K LED Cobra Head Fixture	$13.62	-	$ -			
	123W 11070K LED Flood Light Fixture	$13.41	-	$ -			
	194W 20340K LED Flood Light Fixture	$13.62	-	$ -			
	297W 32850K LED Flood Light Fixture	$13.93	-	$ -			
	Special Agreement Customer Installed LED - Avg.	$13.02	10,671	$ 138,888			
Total Rate OL	**Luminaires**		**108,601**				
	Customers		n/a				
	Meters		**-**				
	KWH	$ -	**7,625,729**				
	Revenue			**$ 1,813,368**	**$ -**	**$ -**	**$ 1,813,368**
Total Retail	**Customers**		**395,086**				
	Meters		**n/a**				
	Luminaires		**109,135**				
	Billing Demand		**895,302**				
	KWH		**479,121,307**				
	Revenue			**$ 9,021,216**	**$ 8,169,143**	**$ 7,593,315**	**$ 24,791,847**

(1) See page 14 for support of customer counts and kWh data.

Unitil Energy Systems, Inc.
Calculation of Distribution Revenue at the Rate Level Effective June 1, 2021 - December 31, 2021
Based on Billing Determinants for June through December 2021

Rate Class	Customer Group		(a) 6/1/2021 Monthly Distribution Charge (1)	(b) Jun - Dec Billing Determinants (2)	(c) Calculated Revenue = (a) X (b): Customer/ Meter/ Luminaire	Demand	kWh	Total
Residential Rate R	Standard Rate	Customer Charge	$ 16.22	481,475	$ 7,809,523			
		All kWh	$ 0.03942	308,344,971			$ 12,154,959	$ 19,964,482
Total Rate R		**Customers**		**481,475**				
		Meters		**n/a**				
		KWH		**308,344,971**				
		Revenue			**$ 7,809,523**	**$ -**	**$ 12,154,959**	**$ 19,964,482**
General Rate G2	Standard Rate	Customer Charge	$ 29.19	74,796	$ 2,183,293			
		Demand charge (All KW)	$ 10.51	789,800		$ 8,300,793		
		All KWH	$ 0.00384	192,820,651			$ 740,431	
		Transformer Ownership Credit, G2	$ (0.50000)	23,805		$ (11,902)		$ 11,224,517
	G2 - kWh Meter	Customer Charge	$ 18.38	2,603	$ 47,843			
		All KWH	$ 0.01267	230,780			$ 2,924	$ 50,767
	QR Water Heating and/or Space Heat	Customer Charge	$ 9.73	1,762	$ 17,144			
		All KWH	$ 0.03588	1,977,219			$ 70,943	$ 88,087
Total Rate G2		**Customers**		**79,161**				
		Meters		**n/a**				
		Billing demand		**789,800**				
		KWH		**195,028,650**				
		Revenue			**$ 2,248,280**	**$ 8,288,890**	**$ 814,298**	**$ 11,363,371**
Large General Rate G1	Standard Rate	Customer Charge Secondary Voltage	$ 162.18	126	$ 20,412			
		Customer Charge Primary Voltage	$ 86.49	1,766	$ 152,774			
		All kVA	$ 7.60	604,403		$ 4,593,461		
		All KWH	$ 0.00384	198,864,288			$ 763,639	
		Transformer Ownership Credit, G1	$ (0.50000)	192,218		$ (96,109)		$ 5,434,176
Total Rate G1		**Customers Secondary Voltage**		**126**				
		Customers Primary Voltage		**1,766**				
		Meters		**n/a**				
		Billing demand		**604,403**				
		KWH		**198,864,288**				
		Revenue			**$ 173,185**	**$ 4,497,352**	**$ 763,639**	**$ 5,434,176**

Outdoor Lighting Rate OL	100W Mercury Vapor Street		$13.28	13,919	$ 184,842			
	175W Mercury Vapor Street		$15.75	793	$ 12,493			
	250W Mercury Vapor Street		$17.85	771	$ 13,754			
	400W Mercury Vapor Street		$21.25	1,298	$ 27,584			
	1000W Mercury Vapor Street		$42.19	24	$ 1,013			
	250W Mercury Vapor Flood		$19.02	665	$ 12,652			
	400W Mercury Vapor Flood		$22.75	901	$ 20,505			
	1000W Mercury Vapor Flood		$37.70	144	$ 5,429			
	100W Mercury Vapor Power Bracket		$13.41	3,894	$ 52,213			
	175W Mercury Vapor Power Bracket		$14.87	557	$ 8,277			
	50W Sodium Vapor Street		$13.52	35,908	$ 485,479			
	100W Sodium Vapor Street		$15.22	1,309	$ 19,930			
	150W Sodium Vapor Street		$15.28	3,906	$ 59,691			
	250W Sodium Vapor Street		$19.14	12,893	$ 246,776			
	400W Sodium Vapor Street		$24.13	2,711	$ 65,421			
	1000W Sodium Vapor Street		$41.66	1,606	$ 66,885			
	150W Sodium Vapor Flood		$17.61	2,690	$ 47,379			
	250W Sodium Vapor Flood		$20.76	3,790	$ 78,671			
	400W Sodium Vapor Flood		$23.58	4,857	$ 114,525			
	1000W Sodium Vapor Flood		$42.03	2,467	$ 103,675			
	50W Sodium Vapor Power Bracket		$12.51	1,387	$ 17,355			
	100W Sodium Vapor Power Bracket		$14.04	904	$ 12,691			
	175W Metal Halide Street		$19.91	1	$ 20			
	250W Metal Halide Street		$21.65	-	$ -			
	400W Metal Halide Street		$22.45	-	$ -			
	175W Metal Halide Flood		$23.00	-	$ -			
	250W Metal Halide Flood		$24.83	-	$ -			
	400W Metal Halide Flood		$24.88	-	$ -			
	175W Metal Halide Power Bracket		$32.22	535	$ 17,222			
	250W Metal Halide Power Bracket		$18.63	-	$ -			
	400W Metal Halide Power Bracket		$19.81	-	$ -			
	1000W Metal Halide Flood (Contracts)		$21.17	-	$ -			
	42W 3780 K LED Area Light Fixture		$13.16	-	$ -			
	57W 5130K LED Area Light Fixture		$13.21	-	$ -			
	25W 2500K LED Cobra Head Fixture		$13.11	-	$ -			
	88W 8800K LED Cobra Head Fixture		$13.30	-	$ -			
	108W 10800K LED Cobra Head Fixture		$13.36	-	$ -			
	193W 19300K LED Cobra Head Fixture		$13.62	-	$ -			
	123W 11070K LED Flood Light Fixture		$13.41	-	$ -			
	194W 20340K LED Flood Light Fixture		$13.62	-	$ -			
	297W 32850K LED Flood Light Fixture		$13.93	-	$ -			
	Special Agreement Customer Installed LED - Avg.		$13.02	10,671	$ 138,888			
Total Rate OL		**Luminaires**		**108,601**				
		Customers		n/a				
		Meters		**-**				
		KWH	$ -	**4,010,049**				
		Revenue			**$ 1,813,368**	**$ -**	**$ -**	**$ 1,813,368**
Total Retail		**Customers**		**560,762**				
		Meters		**n/a**				
		Luminaires		**109,135**				
		Billing Demand		**1,394,202**				
		KWH		**706,247,958**				
		Revenue			**$ 12,044,356**	**$ 12,786,242**	**$ 13,732,896**	**$ 38,575,396**

(1) See page 14 for support of customer counts and kWh data.

Bill Impacts of Changes in System Benefits Charge - Unitil Energy Systems, Inc.
Rates Proposed for Effect May 1, 2022

	Current	May 1
System Benefits Charge ($/kWh) Residential	$ 0.00752	$ 0.00681
System Benefits Charge ($/kWh) C&I	$ 0.00752	$ 0.00681
Bill per month, including UES Default Service Charge		
Residential Rate R (625 kWh/month)	$ 109.78	$ 109.33
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)	$ 1,479.39	$ 1,472.29
Change from previous rate level - $ per month		
Residential Rate R (625 kWh/month)		$ (0.44)
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		$ (7.10)
Change from previous rate level - %		
Residential Rate R (625 kWh/month)		-0.4%
General Service Rate G, three-phase service (40 kW, 10,000 kWh/month)		-0.5%

Unitil Energy Systems, Inc.
Average Distribution Rate Support
January - December 2021

(a)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
No. of Customers								
				Customer Charge				
Rate Class	Jan-June	June	Jan-May (d)-(e)	in Effect	Customers (d)/(g)	Total 2021	Jun-Dec (i)-(f)	Customers (j)/(g)
Residential	$6,622,012	$1,120,289	$5,501,724	$16.22	339,194	$13,311,246	$7,809,523	481,475
G2 kWh Meter	$41,023	$6,893	$34,130	$18.38	1,857	81973.49	$47,843	2,603
G2 QR Water Heating and/or Space Heat	$14,692	$2,442	$12,250	$9.73	1,259	$29,394	$17,144	1,762
G2	$1,850,606	$312,304	$1,538,302	$29.19	52,700	$3,721,594.81	$2,183,293	74,796
G1 Primary Voltage	$131,041	$22,056	$108,985	$86.49	1,260	261758.52	$152,774	1,766
G1 Secondary Voltage	$15,311	$2,854	$12,456	$162.18	77	32868.03	$20,412	126
OL	$0	$0	$0	n/a	n/a	0	$0	n/a
	Jan - June	June	Jan - May		Customers	Total 2021	Jun - Dec	Customers
G2 Transformer Ownership Credits	($9,522)	($1,349)	($8,174)	($0.50)	16,347	($20,076)	($11,902)	23,805
G1 Transformer Ownership Credits	($78,079)	($13,900)	($64,178)	($0.50)	128,356	($160,287)	($96,109)	192,218
kWh Usage	Jan-June	June	Jan-May	Total 2021	June - Dec			
Residential	254,635,025	43,474,063	211,160,962	519,505,933	308,344,971			
G2 kWh Meter	228,466	32,128	196,338	427,118	230,780			
G2 QR Water Heating and/or Space Heat	2,703,123	253,874	2,449,249	4,426,468	1,977,219			
G2	156,247,567	27,905,191	128,342,376	321,163,027	192,820,651			
G1 Primary Voltage	63,225,898	17,923,788	45,302,110	197,903,124	152,601,014			
G1 Secondary Voltage	95,061,712	11,017,169	84,044,543	130,307,817	46,263,274			
OL	3,396,759	568,583	2,828,176	6,838,225	4,010,049			
				Calculated			Calculated	
Distribution Revenues			Jan-May	Dist rates	Total 2021	June -Dec	Dist rates	
Residential	$9,149,952	$1,636,823	$7,513,130	0.03558	$19,591,180	$12,078,050	0.03917	
G2 kWh Meter	$2,080	$347	$1,734	0.00883	$4,598	$2,864	0.01241	
G2 QR Water Heating and/or Space Heat	$87,085	$8,611	$78,474	0.03204	$148,919	$70,445	0.03563	
G2	$57,968	$57,967	$1	0	$691,225	$691,224	0.00358	
G1 Primary Voltage	$38,417	$38,417	$0	0	$433,328	$433,328	0.00284	
G1 Secondary Voltage	$22,152	$22,152	$0	0	$279,388	$279,388	0.00604	
Ol	$891,334	$149,733	$741,601	0.26222	$1,791,843	$1,050,243	0.2619	
Demand Usage (kW, kVA)								
G2 Demand	613,381	119,497	493,884		1,283,683	789,800		
G1 Demand	490,332	88,914	401,418		1,005,821	604,403		
Demand Revenue								
G2 Distribution Demand	$6,446,657	$1,255,921	$5,190,736	$10.51	$13,491,551	$8,300,815	$10.51	
G1 Distribution Demand	$3,726,525	$675,746	$3,050,778	$7.60	$7,644,239	$4,593,461	$7.60	

Note: G1 excludes backup/auxiliary service customer.

Program Cost-Effectiveness - 2022 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	1.96	1.96	3,321.9	3,321.9	1,698.8	-	131.7	2,600.5	20.7	34.7	299	6,729.9	126,196.4
A1 - Energy Star Homes	1.30	2.03	1,455.3	1,292.6	637.8	479.3	-	-	-	-	249	5,386.1	134,653.3
A2 - Home Performance with Energy Star	2.49	2.73	3,723.1	3,297.4	1,206.9	286.9	73.7	699.2	15.3	11.6	491	17,034.2	337,127.3
A3 - Energy Star Products	1.39	2.41	3,399.8	3,007.1	1,246.4	1,198.3	28.6	476.7	9.2	0.1	2,710	19,363.6	319,441.7
A4 - Residential Behavior	1.17	1.03	189.7	166.7	162.5	-	-	-	-	-	30,000	17,325.4	17,325.4
A6c - Residential Education	-	-	-	-	70.6	-	-	-	-	-		-	-
Sub-Total Residential	**1.73**	**2.21**	**12,089.8**	**11,085.7**	**5,023.0**	**1,964.5**	**234.0**	**3,776.4**	**45.2**	**46.4**	**33,749**	**65,839.3**	**934,744.1**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.71	3.34	7,118.5	6,302.8	1,888.3	2,268.7	-	-	-	-	438	49,140.0	712,616.1
C2 - Small Business Energy Solutions	1.49	2.75	4,682.0	4,248.7	1,544.9	1,595.2	-	-	-	-	2,294	22,845.2	402,181.1
C6c - C&I Education	-	-	-	-	38.0	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.61**	**3.04**	**11,800.5**	**10,551.6**	**3,471.1**	**3,863.9**	**-**	**-**	**-**	**-**	**2,732**	**71,985.2**	**1,114,797.2**
Total	**1.67**	**2.55**	**23,890.4**	**21,637.31**	**8,494.1**	**5,828.4**	**234.0**	**3,776.4**	**45.2**	**46.4**	**36,481**	**137,824.5**	**2,049,541.3**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322 and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 15% for Residential and 15% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual kWh Savings	234,042	0.6%	**kWh < 65%**
Annual MMBTU Savings (in kWh)	40,392,366	99.4%	
	40,626,408	100.0%	

Lifetime kWh Savings	3,776,414	0.6%	**kWh < 65%**
Lifetime MMBTU Savings (in kWh)	600,661,281	99.4%	
	604,437,695	100.0%	

Annual Net Savings as a % of 2019 Sales	0.78%

Spending per Customer	Low-Income	$ 316.00
	Residential	$ 37.35
	C&I	$ 237.46

Present Value Benefits - 2022 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environmental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 3,322**	$ 10	$ -	$ 52	$ 54	$ -	$ 42	$ 48	$ 29	$ 25	$ 8	**$ 269**	$ 1,042	$ 2	**$ 1,313**	$ 165	$ 1,844	**$ 2,009**	**$ 93**
A1 - Energy Star Homes	**$ 1,293**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 1,085	$ -	**$ 1,085**	$ 208	$ 163	**$ 370**	**$ -**
A2 - Home Performance with Energy Star	**$ 3,297**	$ 1	$ -	$ 10	$ 10	$ -	$ 15	$ 15	$ 6	$ 5	$ 3	**$ 65**	$ 2,773	$ 4	**$ 2,842**	$ 456	$ 426	**$ 881**	**$ 31**
A3 - Energy Star Products	**$ 3,007**	$ 0	$ -	$ 0	$ 0	$ -	$ 14	$ 18	$ (0)	$ (0)	$ 2	**$ 33**	$ 2,585	$ -	**$ 2,618**	$ 389	$ 393	**$ 782**	**$ 18**
A4 - Residential Behavior	**$ 167**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 153	$ -	**$ 153**	$ 13	$ 23	**$ 36**	**$ -**
A6c - Residential Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Residential	**$ 11,086**	**$ 12**	**$ -**	**$ 62**	**$ 64**	**$ -**	**$ 70**	**$ 81**	**$ 34**	**$ 30**	**$ 13**	**$ 367**	**$ 7,638**	**$ 6**	**$ 8,011**	**$ 1,230**	**$ 2,848**	**$ 4,079**	**$ 142**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 6,303**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 5,438	$ -	**$ 5,438**	$ 865	$ 816	**$ 1,681**	**$ -**
C2 - Small Business Energy Solutions	**$ 4,249**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 2,889	$ 829	**$ 3,718**	$ 531	$ 433	**$ 964**	**$ -**
C6c - C&I Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Commercial & Industrial	**$ 10,552**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,326**	**$ 829**	**$ 9,156**	**$ 1,396**	**$ 1,249**	**$ 2,645**	**$ -**
Total	**$ 21,637**	**$ 12**	**$ -**	**$ 62**	**$ 64**	**$ -**	**$ 70**	**$ 81**	**$ 34**	**$ 30**	**$ 13**	**$ 367**	**$ 15,964**	**$ 836**	**$ 17,166**	**$ 2,626**	**$ 4,097**	**$ 6,724**	**$ 142**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2022

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime MMBtu Savings	2,049,541	*1,537,156*		-	2.475%	-	$ 210,230	*$ 262,788*	$ -	Program Cost Effectiveness (Page 1 of 6)
2	Annual MMBtu Savings	137,824	*103,368*		-	1.100%	-	$ 93,436	*$ 116,794*	$ -	Program Cost Effectiveness (Page 1 of 6)
3	Total Resource Benefits	$ 17,166,476			-						Present Value Benefits (Page 2 of 6)
4	Total Utility Costs[1]	$ 8,494,145			-						Program Cost Effectiveness (Page 1 of 6)
5	Net Benefits	$ 8,672,330	*$ 6,504,248*	$ -	-	1.925%	-	$ 163,512	*$ 204,390*	$ -	Line 3 minus line 4
6	Total					5.500%	-	$ 467,178	*$ 583,972*	$ -	Sum of Rows 1, 2 & 5

		Granite State Test		
		Planned	Actual	Source
7	Total Benefits	$ 21,637,311		Program Cost Effectiveness (Page 1 of 6)
8	Performance Incentive	$ 467,178	$ -	from row 6 above
9	Total Utility Costs	$ 8,494,145	$ -	from row 4 above
10	**Portfolio GST BCR**	**2.41**	**-**	row 7 divided by rows 8+9

Costs, Benefits, and PI Expressed in 2022 Dollars.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

Program Cost-Effectiveness - 2023 Compliance Plan

	Benefit/Cost Ratios		Benefits ($000)										
	Total Resource Cost Test	Granite State Test	Total Resource Cost Test	Granite State Test	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Annual Net MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs													
B1 - Home Energy Assistance	2.10	2.10	3,622.8	3,622.8	1,722.6	-	135.7	2,679.7	-	74.8	308	6,934.9	130,039.8
A1 - Energy Star Homes	1.06	1.64	1,145.0	1,024.5	625.0	455.0	-	-	-	-	239	5,282.2	132,053.8
A2 - Home Performance with Energy Star	2.63	2.88	3,753.9	3,327.8	1,154.2	273.0	73.6	697.8	12.7	16.0	416	16,405.1	327,696.9
A3 - Energy Star Products	1.43	2.35	3,116.7	2,760.7	1,173.6	1,000.9	21.6	357.6	6.9	0.5	2,627	17,848.8	293,273.3
A4 - Residential Behavior	1.83	1.61	310.2	272.8	169.6	-	-	-	-	-	30,000	28,410.0	28,410.0
A6c - Residential Education	-	-	-	-	74.9	-	-	-	-	-	-	-	-
Sub-Total Residential	**1.80**	**2.24**	**11,948.7**	**11,008.6**	**4,919.9**	**1,729.0**	**230.9**	**3,735.1**	**19.5**	**91.4**	**33,590**	**74,880.9**	**911,473.8**
Commercial, Industrial & Municipal													
C1 - Large Business Energy Solutions	1.76	3.48	7,742.5	6,862.7	1,971.7	2,433.0	-	-	-	-	444	49,999.1	751,638.2
C2 - Small Business Energy Solutions	1.50	2.66	4,929.3	4,470.5	1,681.2	1,613.1	-	-	-	-	2,495	23,080.6	411,783.1
C6c - C&I Education	-	-	-	-	40.2	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.64**	**3.07**	**12,671.8**	**11,333.2**	**3,693.0**	**4,046.1**	**-**	**-**	**-**	**-**	**2,939**	**73,079.7**	**1,163,421.3**
Total	**1.71**	**2.59**	**24,620.4**	**22,341.8**	**8,612.9**	**5,775.1**	**230.9**	**3,735.1**	**19.5**	**91.4**	**36,529**	**147,960.6**	**2,074,895.1**

Notes:
(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the illustrative Total Resource Cost Test, NEI adders of 15% for Residential and 15% for C&I are applied to total benefits excluding water.
(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.
(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2023.

Annual kWh Savings	230,927	0.5%	**kWh < 65%**	**Lifetime** kWh Savings	3,735,144	0.6%	**kWh < 65%**
Annual MMBTU Savings (in kWh)	43,362,964	99.5%		**Lifetime** MMBTU Savings (in kWh)	608,091,752	99.4%	
	43,593,891	100.0%			**611,826,896**	100.0%	

Annual Net Savings as a % of 2019 Sales	0.84%

Spending per Customer	Low-Income	$	320.42
	Residential	$	35.93
	C&I	$	252.64

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)[1]	Resource Benefits ($000)														Non-Resource Benefits ($000)			Environmental Benefits ($000)[3]
		Electric											Non-Electric						
		CAPACITY					ENERGY												
	Granite State Test	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Other Fuels	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits[2]	Total Non-Resource Benefits	
Residential Programs																			
B1 - Home Energy Assistance	**$ 3,623**	$ 23	$ -	$ 115	$ 119	$ -	$ 11	$ 7	$ 62	$ 52	$ 7	**$ 396**	$ 1,101	$ 2	**$ 1,499**	$ 184	$ 1,939	**$ 2,124**	**$ 94**
A1 - Energy Star Homes	**$ 1,024**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 804	$ -	**$ 804**	$ 221	$ 121	**$ 341**	**$ -**
A2 - Home Performance with Energy Star	**$ 3,328**	$ 3	$ -	$ 17	$ 17	$ -	$ 11	$ 10	$ 10	$ 8	$ 3	**$ 79**	$ 2,762	$ 4	**$ 2,845**	$ 483	$ 426	**$ 909**	**$ 29**
A3 - Energy Star Products	**$ 2,761**	$ 0	$ -	$ 1	$ 1	$ -	$ 10	$ 13	$ (0)	$ (0)	$ 2	**$ 26**	$ 2,347	$ -	**$ 2,373**	$ 388	$ 356	**$ 744**	**$ 13**
A4 - Residential Behavior	**$ 273**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 249	$ -	**$ 249**	$ 24	$ 37	**$ 61**	**$ -**
A6c - Residential Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Residential	**$ 11,009**	**$ 27**	**$ -**	**$ 133**	**$ 137**	**$ -**	**$ 32**	**$ 30**	**$ 72**	**$ 60**	**$ 11**	**$ 501**	**$ 7,263**	**$ 7**	**$ 7,770**	**$ 1,299**	**$ 2,879**	**$ 4,178**	**$ 137**
Commercial/Industrial Programs																			
C1 - Large Business Energy Solutions	**$ 6,863**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 5,865	$ -	**$ 5,865**	$ 997	$ 880	**$ 1,877**	**$ -**
C2 - Small Business Energy Solutions	**$ 4,470**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 3,059	$ 819	**$ 3,878**	$ 593	$ 459	**$ 1,052**	**$ -**
C6c - C&I Education	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Commercial & Industrial	**$ 11,333**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,924**	**$ 819**	**$ 9,743**	**$ 1,590**	**$ 1,339**	**$ 2,929**	**$ -**
Total	**$ 22,342**	**$ 27**	**$ -**	**$ 133**	**$ 137**	**$ -**	**$ 32**	**$ 30**	**$ 72**	**$ 60**	**$ 11**	**$ 501**	**$ 16,187**	**$ 825**	**$ 17,513**	**$ 2,889**	**$ 4,218**	**$ 7,107**	**$ 137**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

	Portfolio Planned Versus Actual Performance - 2023										
	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime MMBtu Savings	2,074,895	*1,556,171*		-	2.475%	-	$ 213,170	*$ 266,463*	$ -	Program Cost Effectiveness (Page 4 of 6)
2	Annual MMBtu Savings	147,961	*110,970*		-	1.100%	-	$ 94,742	*$ 118,428*	$ -	Program Cost Effectiveness (Page 4 of 6)
3	Total Resource Benefits	$ 17,513,219			-						Present Value Benefits (Page 5 of 6)
4	Total Utility Costs[1]	$ 8,612,949			-						Program Cost Effectiveness (Page 4 of 6)
5	Net Benefits	$ 8,900,269	*$ 6,675,202*	$ -	-	1.925%	-	$ 165,799	*$ 207,249*	$ -	Line 3 minus line 4
6	Total					5.500%	-	$ 473,712	*$ 592,140*	$ -	Sum of Rows 1, 2 & 5

		Granite State Test		
		Planned	Actual	Source
7	Total Benefits	$ 22,341,790		Program Cost Effectiveness (Page 4 of 6)
8	Performance Incentive	$ 473,712	$ -	from row 6 above
9	Total Utility Costs	$ 8,612,949	$ -	from row 4 above
10	**Portfolio GST BCR**	**2.46**	**-**	row 7 divided by rows 8+9

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $489,107.85.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization	Air Sealing, Gas	G21B1a001	299	308	19.1	19.7	286.2	294.9	3.0	-	5.0	10.8	1,229.7	1,267.1	18,444.8	19,006.6
B1a - HEA (Weatherization	Faucet Aerator, Gas	G21B1a002	4	4	-	-	-	-	-	-	-	-	3.0	3.1	21.3	21.9
B1a - HEA (Weatherization	Hand Held Showerhead, Gas	G21B1a003	28	29	-	-	-	-	-	-	-	-	69.4	71.5	485.6	500.4
B1a - HEA (Weatherization	Insulation, Gas	G21B1a004	641	661	112.6	116.1	2,314.3	2,384.7	17.7	-	29.6	64.0	3,425.6	3,530.0	70,381.1	72,524.6
B1a - HEA (Weatherization	LED Bulb, General Service Lamps	G21B1a005	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Linear	G21B1a006	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Other Specialty	G21B1a007	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Bulb, Reflector	G21B1a008	-	-									-	-	-	-
B1a - HEA (Weatherization	LED Fixture	G21B1a009	-	-									-	-	-	-
B1a - HEA (Weatherization	Low Flow Showerhead, Gas	G21B1a010	6	6	-	-	-	-	-	-	-	-	7.7	8.0	54.0	55.7
B1a - HEA (Weatherization	Pipe Insulation - Hot Water, Gas	G21B1a011	1	1	-	-	-	-	-	-	-	-	13.7	14.2	206.1	212.4
B1b - HEA (HVAC Systems	Boiler Replacement, Gas	G21B1b001	59	61	-	-	-	-	-	-	-	-	1,542.7	1,589.7	29,312.0	30,204.7
B1b - HEA (HVAC Systems	Furnace Replacement, Gas	G21B1b002	12	12	-	-	-	-	-	-	-	-	360.6	371.6	6,129.7	6,316.4
B1b - HEA (HVAC Systems	Programmable Thermostat, Gas	G21B1b003	10	11	-	-	-	-	-	-	-	-	77.4	79.8	1,161.7	1,197.1
B1b - HEA (HVAC Systems	Wifi Thermostat, Gas	G21B1b004	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Hydronic	G21B1a015	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Insulation, Ducts	G21B1a016	-	-									-	-	-	-
B1a - HEA (Weatherization	Duct Sealing	G21B1a017	-	-									-	-	-	-
B1b - HEA (HVAC Systems	HVAC Repair: Boiler - Condensing, Water	G21B1b005	-	-									-	-	-	-
B1b - HEA (HVAC Systems	HVAC Repair: Boiler - Steam	G21B1b006	-	-									-	-	-	-
B1b - HEA (HVAC Systems	HVAC Repair: Boiler -Water	G21B1b007	-	-									-	-	-	-
B1b - HEA (HVAC Systems	HVAC Repair: Furnace - Condensing, Ducted	G21B1b008	-	-									-	-	-	-
B1b - HEA (HVAC Systems	HVAC Repair: Furnace - Ducted	G21B1b009	-	-									-	-	-	-
B1a - HEA (Weatherization	Tank Wrap	G21B1a018	-	-									-	-	-	-
B1a - HEA (Weatherization	Hot Water Setback	G21B1a019	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Indirect Water Heater (attached to ES FHW Boiler; Con	G21B1b010	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Integrated Water Heater w/Condensing Boiler >= 90%	G21B1b011	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Integrated Water Heater w/Condensing Boiler >= 95%	G21B1b012	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Tankless On-Demand Water Heater, >= .82	G21B1b013	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Tankless On-Demand Water Heater, UEF .87+	G21B1b014	-	-									-	-	-	-
B1b - HEA (HVAC Systems	ES Storage Water Heater, Med Draw UEF .64+, High D	G21B1b015	-	-									-	-	-	-
B1b - HEA (HVAC Systems	Condensing Water Heater, UEF of .80+	G21B1b016	-	-									-	-	-	-
B1a - HEA (Weatherization	Window Insert	G21B1a020	-	-									-	-	-	-
	Home Energy Assistance Subtotal				**131.7**	**135.7**	**2,600.5**	**2,679.7**	**20.7**	**-**	**34.7**	**74.8**	**6,729.9**	**6,934.9**	**126,196.4**	**130,039.8**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A1a - ES Homes	Cooling, Electric, SF	E21A1a001	-	-									-	-	-	-
A1a - ES Homes	Heating, Gas, SF	G21A1a002	170	169	-	-	-	-	-	-	-	-	4,690.2	4,662.6	117,254.7	116,565.0
A1a - ES Homes	Hot Water, Gas, SF	G21A1a003	-	-									-	-	-	-
A1a - ES Homes	Cooling, Electric, MF	E21A1a002	-	-									-	-	-	-
A1a - ES Homes	Heating, Gas, MF	G21A1a005	79	70	-	-	-	-	-	-	-	-	695.9	619.6	17,398.6	15,488.8
A1a - ES Homes	Hot Water, Gas, MF	G21A1a006	-	-									-	-	-	-
A1a - ES Homes	LED Bulb - SF	G21A1a007	-	-									-	-	-	-
A1a - ES Homes	LED Bulb (MF)	G21A1a008	-	-									-	-	-	-
A1a - ES Homes	Clothes Washer	G21A1a009	-	-									-	-	-	-
	ES Homes Subtotal				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5,386.1**	**5,282.2**	**134,653.3**	**132,053.8**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherizat	Air Sealing, Gas	G21A2a001	134	134	1.7	1.7	25.4	25.4	0.3	-	0.4	0.9	1,647.3	1,647.4	24,709.0	24,711.1
A2a - HPwES (Weatherizat	Faucet Aerator, Gas	G21A2a002	33	33	-	-	-	-	-	-	-	-	5.9	5.9	41.4	41.4
A2a - HPwES (Weatherizat	Hand Held Showerhead, Gas	G21A2a003	37	37	0.5	0.5	3.4	3.4	0.1	-	0.1	-	16.3	16.3	114.1	114.1
A2a - HPwES (Weatherizat	Insulation, Gas	G21A2a004	299	299	12.7	12.7	274.7	274.7	2.0	-	3.3	7.0	12,127.3	12,128.4	262,903.4	262,925.5
A2a - HPwES (Weatherizat	LED Bulb, General Service Lamps	G21A2a005	840	840	35.4	35.4	177.2	177.2	7.6	7.6	4.9	4.9	-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Linear	G21A2a006	-	-									-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Other Specialty	G21A2a007	202	202	10.1	10.1	50.5	50.5	2.2	2.2	1.4	1.4	-	-	-	-
A2a - HPwES (Weatherizat	LED Bulb, Reflector	G21A2a008	88	88	4.4	4.4	21.9	21.9	0.9	0.9	0.6	0.6	-	-	-	-
A2a - HPwES (Weatherizat	LED Fixture	G21A2a009	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Low Flow Showerhead, Gas	G21A2a010	48	48	-	-	-	-	-	-	-	-	23.8	23.8	166.9	166.9
A2a - HPwES (Weatherizat	Pipe Insulation - Hot Water, Gas	G21A2a011	12	12	0.3	0.3	4.7	4.7	0.0	-	0.1	-	23.8	23.8	357.4	357.4
A2b - HPwES (HVAC Syste	Ancillary Savings – Central AC	G21A2b007	1	1	0.5	0.5	2.3	2.3	-	-	0.3	0.3	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Mini-Split AC / HP	G21A2b009	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Boiler Circulator Pump	G21A2b005	80	80	1.3	1.3	26.7	26.7	0.4	0.4	-	-	197.8	197.8	3,956.4	3,956.7
A2b - HPwES (HVAC Syste	Ancillary Savings – Furnace	G21A2b006	62	62	5.1	5.1	86.8	86.8	1.5	1.5	-	-	-	-	-	-
A2b - HPwES (HVAC Syste	Ancillary Savings – Room AC	G21A2b008	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Hydronic	G21A2a015	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Insulation, Ducts	G21A2a016	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Duct Sealing	G21A2a017	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Tank Wrap	G21A2a018	-	-									-	-	-	-
A2a - HPwES (Weatherizat	Hot Water Setback	G21A2a019	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Boiler Replacement, Gas	G21A2b001	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Furnace Replacement, Gas	G21A2b002	-	-									-	-	-	-
A2b - HPwES (HVAC Syste	Programmable Thermostat, Gas	G21A2b003	219	219	1.3	1.3	18.9	18.9	0.2	-	0.3	0.7	95.7	95.7	1,434.8	1,434.9
A2b - HPwES (HVAC Syste	Wifi Thermostat, Gas	G21A2b004	512	401	0.4	0.3	6.6	5.2	0.1	-	0.1	0.2	2,896.3	2,265.9	43,444.0	33,988.9
	Home Performance with Energy Star Subtotal				**73.7**	**73.6**	**699.2**	**697.8**	**15.3**	**12.7**	**11.6**	**16.0**	**17,034.2**	**16,405.1**	**337,127.3**	**327,696.9**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A3c - ES HVAC Systems	Early Replacement Boiler, FHW - EE 90 AFUE (80%-9	G21A3b001	-	-									-	-	-	-
A3c - ES HVAC Systems	Early Replacement Boiler, FHW - Retirement: 90 AFUE	G21A3b002	-	-									-	-	-	-
A3c - ES HVAC Systems	Early Replacement Boiler, Steam - EE: 82%+ AFUE	G21A3b003	-	-									-	-	-	-
A3c - ES HVAC Systems	Early Replacement Boiler, Steam - Retirement: 82%+ A	G21A3b004	-	-									-	-	-	-
A3c - ES HVAC Systems	Boiler Reset Controls	G21A3b005	2	2	-	-	-	-	-	-	-	-	8.8	7.0	131.6	105.3
A3c - ES HVAC Systems	Condensing Boiler >= 90% AFUE (Up to 300 MBH)	G21A3b006	16	16	-	-	-	-	-	-	-	-	172.3	137.8	3,273.8	2,619.0
A3c - ES HVAC Systems	Condensing Boiler >= 95% AFUE (Up to 300 MBH)	G21A3b007	115	112	-	-	-	-	-	-	-	-	1,514.8	1,180.2	28,780.8	22,424.0
A3c - ES HVAC Systems	Furnace 95+ AFUE (<150) w/ECM Motor	G21A3b008	260	256	24.1	19.0	409.9	322.9	7.0	5.5	-	-	2,267.7	1,786.3	38,551.2	30,366.5
A3c - ES HVAC Systems	Furnace 97+ AFUE (<150) w/ECM Motor	G21A3b009	90	85	8.3	6.3	141.9	107.2	2.4	1.8	-	-	825.0	623.4	14,025.5	10,597.1
A3c - ES HVAC Systems	Heat Recovery Ventilator (-133 kWh penalty)	G21A3b010	-	-									-	-	-	-
A3c - ES HVAC Systems	Programmable Thermostat	G21A3b011	60	55	1.6	1.5	24.3	22.3	0.3	-	0.4	0.8	210.0	192.5	3,150.0	2,887.5
A3c - ES HVAC Systems	Indirect Water Heater (attached to ES FHW Boiler; Con	G21A3b012	20	18	-	-	-	-	-	-	-	-	80.0	72.0	1,600.0	1,440.0
A3c - ES HVAC Systems	Integrated Water Heater w/Condensing Boiler >= 90%	G21A3b013	-	-									-	-	-	-
A3c - ES HVAC Systems	Integrated Water Heater w/Condensing Boiler >= 95%	G21A3b014	245	237	-	-	-	-	-	-	-	-	3,136.0	3,030.1	59,584.0	57,571.1
A3c - ES HVAC Systems	Condensing Water Heater, UEF of .80+	G21A3b015	-	-									-	-	-	-
A3c - ES HVAC Systems	ES Storage Water Heater, Med Draw UEF .64+, High D	G21A3b016	17	16	(0.7)	(0.7)	(9.5)	(8.9)	(0.1)	(0.1)	(0.1)	(0.1)	51.0	48.0	663.0	624.0
A3c - ES HVAC Systems	Tankless On-Demand Water Heater, >= .82	G21A3b017	-	-									-	-	-	-
A3c - ES HVAC Systems	Tankless On-Demand Water Heater, UEF .87+	G21A3b018	110	105	(4.7)	(4.5)	(89.9)	(85.8)	(0.4)	(0.4)	(0.2)	(0.2)	803.0	766.5	15,257.0	14,563.5
A3c - ES HVAC Systems	WiFi Thermostat (Heating Only)	G21A3b019	1,775	1,725	-	-	-	-	-	-	-	-	10,295.0	10,005.0	154,424.7	150,075.4
A3c - ES HVAC Systems	WiFi Thermostat (Heating & Cooling)	G21A3b020	-	-									-	-	-	-
	ES Products Subtotal				**28.6**	**21.6**	**476.7**	**357.6**	**9.2**	**6.9**	**0.1**	**0.5**	**19,363.6**	**17,848.8**	**319,441.7**	**293,273.3**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A4a - Residential Behavior	Home Energy Reports	G21A4a001	30,000	30,000	-	-	-	-	-	-	-	-	17,325.4	28,410.0	17,325.4	28,410.0
	Residential Behavior Subtotal		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**17,325.4**	**28,410.0**	**17,325.4**	**28,410.0**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1a - LCI Retrofit	Custom Large Hot Water Retro	G21C1a001	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large HVAC Retro	G21C1a002	-	-									-	-	-	-
C1a - LCI Retrofit	Custom Large Other Retro	G21C1a003	34	40	-	-	-	-	-	-	-	-	17,876.6	20,923.6	307,569.0	359,993.3
C1a - LCI Retrofit	Custom Large Process Retro	G21C1a004	-	-									-	-	-	-
C1a - LCI Retrofit	Air Sealing, Gas	G21C1a017	-	-									-	-	-	-
C1a - LCI Retrofit	Insulation, Gas	G21C1a018	-	-									-	-	-	-
C1a - LCI Retrofit	Faucet Aerator, Gas	G21C1a005	-	-									-	-	-	-
C1a - LCI Retrofit	Low Flow Showerhead With Thermostatic Valve, Gas	G21C1a006	-	-									-	-	-	-
C1a - LCI Retrofit	Low Flow Showerhead, Gas	G21C1a007	-	-									-	-	-	-
C1a - LCI Retrofit	Pipe Wrap - Hot Water, Gas	G21C1a008	-	-									-	-	-	-
C1a - LCI Retrofit	Pre Rinse Spray Valve, Gas	G21C1a009	-	-									-	-	-	-
C1a - LCI Retrofit	Boiler Reset Controls, Gas	G21C1a010	-	-									-	-	-	-
C1a - LCI Retrofit	Boiler Tune-Ups	G21C1a011	1	1	-	-	-	-	-	-	-	-	222.1	186.6	444.2	373.1
C1a - LCI Retrofit	Energy Management System, Gas	G21C1a012	1	1	-	-	-	-	-	-	-	-	136.0	114.2	1,360.0	1,142.4
C1a - LCI Retrofit	Pipe Insulation - Heating, Gas	G21C1a013	1	1	-	-	-	-	-	-	-	-	169.4	142.3	2,540.3	2,133.8
C1a - LCI Retrofit	Steam Trap, Gas	G21C1a014	354	354	-	-	-	-	-	-	-	-	13,100.2	11,004.2	78,601.2	66,025.0
C1a - LCI Retrofit	Programmable Thermostat, Gas	G21C1a015	-	-									-	-	-	-
C1a - LCI Retrofit	WiFi Thermostat (Heating & Cooling)	G21C1a016	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Hot Water New	G21C1b001	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large HVAC New	G21C1b002	-	-									-	-	-	-
C1b - LCI New Equipment	Custom Large Other New	G21C1b003	35	35	-	-	-	-	-	-	-	-	17,371.4	17,371.4	315,843.1	315,843.2
C1b - LCI New Equipment	Custom Large Process New	G21C1b004	-	-									-	-	-	-
C1b - LCI New Equipment	Boiler 1701 to 2000 MBH 90 AFUE, Gas	G21C1b005	-	-									-	-	-	-
C1b - LCI New Equipment	Boiler 1000 to 1700 MBH 90 AFUE, Gas	G21C1b006	-	-									-	-	-	-
C1b - LCI New Equipment	Boiler 500 to 999 MBH 90 AFUE, Gas	G21C1b007	3	3	-	-	-	-	-	-	-	-	154.2	154.2	3,855.0	3,855.0
C1b - LCI New Equipment	Boiler 301 to 499 MBH 90 AFUE, Gas	G21C1b008	1	1	-	-	-	-	-	-	-	-	28.0	28.0	700.0	700.0
C1b - LCI New Equipment	Boiler to 300 MBH 90 AFUE, Gas	G21C1b009	-	-									-	-	-	-
C1b - LCI New Equipment	Boiler to 300 MBH 95 AFUE, Gas	G21C1b010	2	2	-	-	-	-	-	-	-	-	35.4	35.4	885.0	885.0
C1b - LCI New Equipment	Combo Condensing Boiler / Water Heater, Gas	G21C1b011	-	-									-	-	-	-
C1b - LCI New Equipment	Combo Furnace / Water Heater, Gas	G21C1b012	-	-									-	-	-	-
C1b - LCI New Equipment	Condensing Unit Heater, Gas	G21C1b013	-	-									-	-	-	-
C1b - LCI New Equipment	Furnace w/ ECM 95 AFUE, Gas	G21C1b014	4	4	-	-	-	-	-	-	-	-	22.8	19.2	410.4	344.7
C1b - LCI New Equipment	Furnace w/ ECM 97 AFUE, Gas	G21C1b015	-	-									-	-	-	-
C1b - LCI New Equipment	Infrared Heater, Gas	G21C1b016	2	2	-	-	-	-	-	-	-	-	24.0	20.2	408.0	342.7
C1b - LCI New Equipment	Faucet Aerator, Gas	G21C1b017	-	-									-	-	-	-
C1b - LCI New Equipment	Low Flow Showerhead With Thermostatic Valve, Gas	G21C1b018	-	-									-	-	-	-
C1b - LCI New Equipment	Low Flow Showerhead, Gas	G21C1b019	-	-									-	-	-	-
C1b - LCI New Equipment	Pre Rinse Spray Valve, Gas	G21C1b020	-	-									-	-	-	-
C1b - LCI New Equipment	Combination Oven, Gas	G21C1b021	-	-									-	-	-	-
C1b - LCI New Equipment	Convection Oven, Gas	G21C1b022	-	-									-	-	-	-
C1b - LCI New Equipment	Conveyor Oven, Gas	G21C1b023	-	-									-	-	-	-
C1b - LCI New Equipment	Fryer, Gas	G21C1b024	-	-									-	-	-	-
C1b - LCI New Equipment	Griddle, Gas	G21C1b025	-	-									-	-	-	-
C1b - LCI New Equipment	Rack Oven, Gas	G21C1b026	-	-									-	-	-	-
C1b - LCI New Equipment	Steam Cooker, Gas	G21C1b027	-	-									-	-	-	-
C1b - LCI New Equipment	C&I Large New Construction Code Compliance	G21C1b028	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Water Heater, Condensing Gas	G21C1c012	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Combination Oven, Gas	G21C1c001	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Convection Oven, Gas	G21C1c002	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Conveyor Oven, Gas	G21C1c003	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Fryer, Gas	G21C1c004	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Griddle, Gas	G21C1c005	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Pre-Rinse Spray Valve, Gas	G21C1c006	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1c - LCI Midstream	Midstream Rack Oven, Gas	G21C1c007	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Steam Cooker, Gas	G21C1c008	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Indirect Water Heater, Gas	G21C1c009	-	-									-	-	-	-
C1c - LCI Midstream	Midstream On Demand Tankless Water Heater, Gas	G21C1c010	-	-									-	-	-	-
C1c - LCI Midstream	Midstream Volume Water Heater, Gas	G21C1c011	-	-									-	-	-	-
	Large Business Energy Solutions Subtotal				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**49,140.0**	**49,999.1**	**712,616.1**	**751,638.2**

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2a - SCI Retrofit	Custom Small Hot Water Retro	G21C2a001	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small HVAC Retro	G21C2a002	-	-									-	-	-	-
C2a - SCI Retrofit	Custom Small Other Retro	G21C2a003	84	99	-	-	-	-	-	-	-	-	7,657.4	8,970.6	150,042.6	175,772.8
C2a - SCI Retrofit	Custom Small Process Retro	G21C2a004	-	-									-	-	-	-
C2a - SCI Retrofit	Air Sealing, Gas	G21C2a017	-	-									-	-	-	-
C2a - SCI Retrofit	Insulation, Gas	G21C2a018	-	-									-	-	-	-
C2a - SCI Retrofit	Faucet Aerator, Gas	G21C2a005	-	-									-	-	-	-
C2a - SCI Retrofit	Low Flow Showerhead With Thermostatic Valve, Gas	G21C2a006	-	-									-	-	-	-
C2a - SCI Retrofit	Low Flow Showerhead, Gas	G21C2a007	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Wrap - Hot Water, Gas	G21C2a008	100	100	-	-	-	-	-	-	-	-	21.0	21.0	315.0	315.0
C2a - SCI Retrofit	Pre Rinse Spray Valve, Gas	G21C2a009	-	-									-	-	-	-
C2a - SCI Retrofit	Boiler Reset Controls, Gas	G21C2a010	-	-									-	-	-	-
C2a - SCI Retrofit	Boiler Tune-Ups	G21C2a011	-	-									-	-	-	-
C2a - SCI Retrofit	Energy Management System, Gas	G21C2a012	-	-									-	-	-	-
C2a - SCI Retrofit	Pipe Insulation - Heating, Gas	G21C2a013	-	-									-	-	-	-
C2a - SCI Retrofit	Steam Trap, Gas	G21C2a014	35	40	-	-	-	-	-	-	-	-	367.0	352.3	2,201.7	2,113.7
C2a - SCI Retrofit	Programmable Thermostat, Gas	G21C2a015	350	400	-	-	-	-	-	-	-	-	1,225.0	1,400.0	18,375.0	21,000.0
C2a - SCI Retrofit	WiFi Thermostat (Heating & Cooling)	G21C2a016	18	20	-	-	-	-	-	-	-	-	63.0	70.0	945.0	1,050.0
C2b - SCI New Equipment	Custom Small Hot Water New	G21C2b001	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small HVAC New	G21C2b002	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Other New	G21C2b003	-	-									-	-	-	-
C2b - SCI New Equipment	Custom Small Process New	G21C2b004	-	-									-	-	-	-
C2b - SCI New Equipment	Boiler 1701 to 2000 MBH 90 AFUE, Gas	G21C2b005	11	12	-	-	-	-	-	-	-	-	1,818.3	1,666.2	45,457.5	41,655.6
C2b - SCI New Equipment	Boiler 1000 to 1700 MBH 90 AFUE, Gas	G21C2b006	11	12	-	-	-	-	-	-	-	-	1,290.5	1,182.6	32,263.6	29,565.2
C2b - SCI New Equipment	Boiler 500 to 999 MBH 90 AFUE, Gas	G21C2b007	25	28	-	-	-	-	-	-	-	-	1,285.0	1,439.2	32,125.1	35,979.9
C2b - SCI New Equipment	Boiler 301 to 499 MBH 90 AFUE, Gas	G21C2b008	11	12	-	-	-	-	-	-	-	-	308.0	336.0	7,700.0	8,400.0
C2b - SCI New Equipment	Boiler to 300 MBH 90 AFUE, Gas	G21C2b009	-	-									-	-	-	-
C2b - SCI New Equipment	Boiler to 300 MBH 95 AFUE, Gas	G21C2b010	18	20	-	-	-	-	-	-	-	-	350.5	389.4	8,761.5	9,735.0
C2b - SCI New Equipment	Combo Condensing Boiler / Water Heater, Gas	G21C2b011	-	-									-	-	-	-
C2b - SCI New Equipment	Combo Furnace / Water Heater, Gas	G21C2b012	-	-									-	-	-	-
C2b - SCI New Equipment	Condensing Unit Heater, Gas	G21C2b013	-	-									-	-	-	-
C2b - SCI New Equipment	Furnace w/ ECM 95 AFUE, Gas	G21C2b014	14	15	-	-	-	-	-	-	-	-	79.8	71.8	1,436.4	1,292.8
C2b - SCI New Equipment	Furnace w/ ECM 97 AFUE, Gas	G21C2b015	-	-									-	-	-	-
C2b - SCI New Equipment	Infrared Heater, Gas	G21C2b016	22	23	-	-	-	-	-	-	-	-	264.0	231.8	4,488.0	3,941.3
C2b - SCI New Equipment	Faucet Aerator, Gas	G21C2b017	997	1,097	-	-	-	-	-	-	-	-	1,694.7	1,565.9	16,893.9	15,610.0
C2b - SCI New Equipment	Low Flow Showerhead With Thermostatic Valve, Gas	G21C2b018	-	-									-	-	-	-
C2b - SCI New Equipment	Low Flow Showerhead, Gas	G21C2b019	450	450	-	-	-	-	-	-	-	-	1,192.5	1,192.5	11,925.0	11,925.0
C2b - SCI New Equipment	Pre Rinse Spray Valve, Gas	G21C2b020	60	65	-	-	-	-	-	-	-	-	159.0	172.3	1,192.5	1,291.9
C2b - SCI New Equipment	Combination Oven, Gas	G21C2b021	-	-									-	-	-	-
C2b - SCI New Equipment	Convection Oven, Gas	G21C2b022	15	18	-	-	-	-	-	-	-	-	535.5	642.6	6,426.0	7,711.2
C2b - SCI New Equipment	Conveyor Oven, Gas	G21C2b023	-	-									-	-	-	-
C2b - SCI New Equipment	Fryer, Gas	G21C2b024	-	-									-	-	-	-
C2b - SCI New Equipment	Griddle, Gas	G21C2b025	-	-									-	-	-	-
C2b - SCI New Equipment	Rack Oven, Gas	G21C2b026	-	-									-	-	-	-
C2b - SCI New Equipment	Steam Cooker, Gas	G21C2b027	-	-									-	-	-	-
C2b - SCI New Equipment	C&I Small New Construction Code Complaince	G21C2b028	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Combination Oven, Gas	G21C2c001	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Convection Oven, Gas	G21C2c002	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Conveyor Oven, Gas	G21C2c003	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Fryer, Gas	G21C2c004	28	32	-	-	-	-	-	-	-	-	2,192.4	2,087.2	26,308.4	25,046.0
C2c - SCI Midstream	Midstream Griddle, Gas	G21C2c005	2	2	-	-	-	-	-	-	-	-	75.8	63.1	909.6	757.7
C2c - SCI Midstream	Midstream Pre-Rinse Spray Valve, Gas	G21C2c006	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Rack Oven, Gas	G21C2c007	-	-									-	-	-	-

			Quantity		Net Annual MWh Savings		Net Lifetime MWh Savings		Annual Net Winter kW		Annual Net Summer kW		Total Net Annual MMBTU		Total Net Lifetime MMBTU	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2c - SCI Midstream	Midstream Steam Cooker, Gas	G21C2c008	-	-									-	-	-	-
C2c - SCI Midstream	Midstream Indirect Water Heater, Gas	G21C2c009	6	7	-	-	-	-	-	-	-	-	114.0	39.9	1,710.0	598.5
C2c - SCI Midstream	Midstream On Demand Tankless Water Heater, Gas	G21C2c010	12	14	-	-	-	-	-	-	-	-	106.8	57.3	2,029.2	1,089.0
C2c - SCI Midstream	Midstream Volume Water Heater, Gas	G21C2c011	25	30	-	-	-	-	-	-	-	-	2,045.0	1,128.8	30,675.0	16,932.6
C2c - SCI Midstream	Midstream Water Heater, Condensing Gas	G21C2c012	-	-									-	-	-	-
	Small Business Energy Solutions Subtotal				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**22,845.2**	**23,080.6**	**402,181.1**	**411,783.1**

Program Cost-Effectiveness - 2022 PLAN

	Granite State Test (Net)	*Utility Cost Test*	*Secondary Granite State Test*	**Total Resource Cost Test (Net)**	**Granite State Test (Net)**	*Utility Cost Test*	*Secondary Granite State Test [1]*	**Utility Costs ($000 - 2022$)[2]**	**Customer Costs ($000 - 2022$)[2]**	**Annual Adj. Gross MWh Savings**	**Annual Net MWh Savings**	**Lifetime Adj. Gross MWh Savings**	**Lifetime Net MWh Savings**	**Winter kW Savings**	**Summer kW Savings**	**Number of Customers Served**	**Annual Net MMBtu Savings**	**Lifetime Net MMBtu Savings**
Residential Programs																		
B1 - Home Energy Assistance	1.03	*0.83*	*1.05*	575.3	575.3	*464.9*	*584.4*	556.9	-	12.8	12.8	273.8	273.8	2.0	3.4	56	2,650.6	57,040.6
A1 - Energy Star Homes	1.83	*1.54*	*1.48*	616.3	547.4	*459.5*	*616.3*	298.5	116.6	-	-	-	-	-	-	106	2,418.0	57,950.0
A2 - Home Performance with Energy Star	1.14	*0.92*	*1.04*	426.4	378.0	*306.6*	*429.5*	332.9	80.5	5.0	5.0	74.7	74.7	1.5	0.1	75	1,795.2	38,165.8
A3 - Energy Star Products	1.95	*1.63*	*1.17*	362.9	321.2	*268.7*	*368.0*	164.6	150.6	7.9	7.9	132.4	132.4	2.4	0.0	182	1,938.0	34,437.7
A4 - Residential Behavior	1.38	*1.27*	*1.57*	64.0	56.3	*51.8*	*64.0*	40.7	-	-	-	-	-	-	-	11,200	5,847.4	5,847.4
Sub-Total Residential	**1.33**	***1.10***	***1.17***	**2,044.9**	**1,878.1**	***1,551.6***	***2,062.2***	**1,411.8**	**347.7**	**25.7**	**25.7**	**480.9**	**480.9**	**5.9**	**3.6**	**11,619**	**14,649.3**	**193,441.5**
Commercial, Industrial & Municipal																		
C1 - Large Business Energy Solutions	3.88	*3.27*	*2.16*	2,976.4	2,641.9	*2,229.7*	*2,976.4*	681.3	698.6	-	-	-	-	-	-	118	21,902.0	325,856.3
C2 - Small Business Energy Solutions	2.66	*2.17*	*2.24*	2,015.0	1,795.3	*1,464.5*	*2,015.0*	675.4	225.4	-	-	-	-	-	-	168	13,598.1	197,483.0
C6c - C&I Education	-	-	-	-	-	-	-	15.9	-	-	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**3.23**	***2.69***	***2.17***	**4,991.3**	**4,437.2**	***3,694.2***	***4,991.3***	**1,372.5**	**924.1**	**-**	**-**	**-**	**-**	**-**	**-**	**286**	**35,500.1**	**523,339.3**
Total	**2.27**	***1.88***	***1.74***	**7,036.3**	**6,315.4**	***5,245.8***	***7,053.6***	**2,784.3**	**1,271.7**	**25.7**	**25.7**	**480.9**	**480.9**	**5.9**	**3.6**	**11,905**	**50,149.3**	**716,780.9**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the Secondary Granite State Test, NEI adders of 15% for Residential and 15% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual Savings as a % of 2019 Sales	0.66%

Spending per Customer		
	Low-Income	$ 439.86
	Residential	$ 33.61
	C&I	$ 195.71

Program Cost-Effectiveness - 2023 PLAN

	Granite State Test (Net)	*Utility Cost Test*	*Secondary Granite State Test*	Total Resource Cost Test (Net)	Granite State Test (Net)	*Utility Cost Test*	*Secondary Granite State Test* [1]	Utility Costs ($000 - 2022$) [2]	Customer Costs ($000 - 2022$) [2]	Annual Adj. Gross MWh Savings	Annual Net MWh Savings	Lifetime Adj. Gross MWh Savings	Lifetime Net MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings
Residential Programs																		
B1 - Home Energy Assistance	1.01	*0.83*	*1.03*	484.1	484.1	*397.5*	*491.7*	479.3	-	10.9	10.9	232.4	232.4	0.0	-	56	2,208.4	47,567.5
A1 - Energy Star Homes	1.93	*1.61*	*1.57*	698.3	620.9	*516.4*	*698.3*	321.2	124.8	-	-	-	-	-	-	106	2,637.0	63,425.0
A2 - Home Performance with Energy Star	1.11	*0.92*	*1.03*	434.8	386.0	*319.7*	*437.7*	347.3	79.6	5.0	5.0	74.7	74.7	1.5	0.1	6	1,798.6	38,254.5
A3 - Energy Star Products	1.83	*1.57*	*1.17*	347.5	308.0	*263.8*	*347.3*	168.2	127.5	7.9	7.9	132.4	132.4	(0.0)	0.1	182	1,835.6	32,492.1
A4 - Residential Behavior	1.30	*1.19*	*1.48*	63.8	56.2	*51.3*	*63.8*	43.3	-	-	-	-	-	-	-	11,200	5,847.4	5,847.4
A6c - Res Education	-	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-	-
Sub-Total Residential	**1.35**	***1.12***	***1.19***	**2,028.6**	**1,855.1**	***1,548.8***	***2,039.0***	**1,379.2**	**331.9**	**23.8**	**23.8**	**439.5**	**439.5**	**1.6**	**0.2**	**11,550**	**14,327.0**	**187,586.5**
Commercial, Industrial & Municipal																		
C1 - Large Business Energy Solutions	3.83	*3.20*	*2.12*	2,163.0	1,922.1	*1,606.5*	*2,163.0*	502.0	520.3	-	-	-	-	-	-	108	14,307.9	220,365.6
C2 - Small Business Energy Solutions	3.10	*2.38*	*2.54*	1,718.2	1,540.6	*1,184.4*	*1,718.2*	497.4	179.1	-	-	-	-	-	-	140	10,830.0	156,347.9
C6c - C&I Education	-	-	-	-	-	-	-	17.9	-	-	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**3.40**	***2.74***	***2.26***	**3,881.3**	**3,462.6**	***2,791.0***	***3,881.3***	**1,017.4**	**699.4**	**-**	**-**	**-**	**-**	**-**	**-**	**248**	**25,137.8**	**376,713.5**
Total	**2.22**	***1.81***	***1.73***	**5,909.9**	**5,317.7**	***4,339.7***	***5,920.3***	**2,396.6**	**1,031.4**	**23.8**	**23.8**	**439.5**	**439.5**	**1.6**	**0.2**	**11,798**	**39,464.8**	**564,300.0**

Notes:

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the Secondary Granite State Test, NEI adders of 25% for Residential and 10% for C&I are applied to total benefits excluding water.

(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.

(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

Annual Savings as a % of 2019 Sales	0.52%

Spending per Customer			
	Low-Income	$	378.61
	Residential	$	35.38
	C&I	$	145.07

Present Value Benefits 2022 Plan

	Total Benefits ($000)			Resource Benefits ($000)																Non-Resource Benefits ($000)			Environ-mental Benefits ($000)
				Electric											Gas Benefit								
				CAPACITY					ENERGY														
	Granite State Test	*Utility Cost Test*	*Secondary Granite State Test*	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric DRIPE	Total Electric Benefit	Gas Benefit	Gas DRIPE	Total Gas Benefit	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits	Total Non-Resource Benefits	
Residential Programs																							
B1 - Home Energy Assistance	**$ 575**	*$ 465*	*$ 584*	$ 1	$ -	$ 5	$ 6	$ -	$ 4	$ 5	$ 3	$ 3	$ 1	**$ 28**	$ 457	$ 8	$ 465	$ -	**$ 493**	$ 82	$ -	**$ 82**	**$ 9**
A1 - Energy Star Homes	**$ 547**	*$ 460*	*$ 616*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 453	$ 7	$ 460	$ -	**$ 460**	$ 88	$ 69	**$ 157**	**$ -**
A2 - Home Performance with Energy Star	**$ 378**	*$ 307*	*$ 430*	$ 0	$ -	$ 0	$ 0	$ -	$ 2	$ 3	$ 0	$ 0	$ 0	**$ 5**	$ 301	$ 5	$ 307	$ 1	**$ 324**	$ 54	$ 48	**$ 103**	**$ 3**
A3 - Energy Star Products	**$ 321**	*$ 269*	*$ 368*	$ 0	$ -	$ 0	$ 0	$ -	$ 4	$ 5	$ (0)	$ (0)	$ 1	**$ 9**	$ 264	$ 5	$ 269	$ -	**$ 278**	$ 43	$ 42	**$ 85**	**$ 5**
A4 - Residential Behavior	**$ 56**	*$ 52*	*$ 64*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 50	$ 2	$ 52	$ -	**$ 52**	$ 5	$ 8	**$ 12**	**$ -**
	$ -	*$ -*	*$ -*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Residential	**$ 1,878**	*$ 1,552*	*$ 2,062*	**$ 1**	**$ -**	**$ 6**	**$ 6**	**$ -**	**$ 10**	**$ 12**	**$ 3**	**$ 3**	**$ 2**	**$ 43**	**$ 1,525**	**$ 27**	**$ 1,552**	**$ 1**	**$ 1,606**	**$ 272**	**$ 167**	**$ 439**	**$ 17**
	$ -	*$ -*	*$ -*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Commercial/Industrial Programs	**$ -**	*$ -*	*$ -*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
C1 - Large Business Energy Solutions	**$ 2,642**	*$ 2,230*	*$ 2,976*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 2,178	$ 51	$ 2,230	$ 24	**$ 2,254**	$ 388	$ 334	**$ 723**	**$ -**
C2 - Small Business Energy Solutions	**$ 1,795**	*$ 1,464*	*$ 2,015*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 1,429	$ 35	$ 1,464	$ 98	**$ 1,562**	$ 233	$ 220	**$ 453**	**$ -**
C3 - Municipal Energy Solutions																							
	$ -	*$ -*	*$ -*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	**$ -**	**$ -**
Sub-Total Commercial & Industrial	**$ 4,437**	*$ 3,694*	*$ 4,991*	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,608**	**$ 87**	**$ 3,694**	**$ 122**	**$ 3,816**	**$ 621**	**$ 554**	**$ 1,175**	**$ -**
Total	**$ 6,315**	*$ 5,246*	*$ 7,054*	**$ 1**	**$ -**	**$ 6**	**$ 6**	**$ -**	**$ 10**	**$ 12**	**$ 3**	**$ 3**	**$ 2**	**$ 43**	**$ 5,132**	**$ 114**	**$ 5,246**	**$ 123**	**$ 5,422**	**$ 893**	**$ 721**	**$ 1,614**	**$ 17**

(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322. Benefits are calculated based on net savings.
(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Present Value Benefits - 2023 PLAN

	Total Benefits ($000)			Resource Benefits ($000)									
				Electric									
				CAPACITY					ENERGY				
	Granite State Test	*Utility Cost Test*	*Secondary Granite State Test*	Summer Generation	Winter Generation	Transmission	Distribution	Reliability	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak
Residential Programs												
B1 - Home Energy Assistance	**$ 484**	*$ 397*	*$ 492*	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1	$ 5	$ 4
A1 - Energy Star Homes	**$ 621**	*$ 516*	*$ 698*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
A2 - Home Performance with Energy Star	**$ 386**	*$ 320*	*$ 438*	$ 0	$ -	$ 0	$ 0	$ -	$ 2	$ 3	$ 0	$ 0
A3 - Energy Star Products	**$ 308**	*$ 264*	*$ 347*	$ 0	$ -	$ 0	$ 0	$ -	$ (0)	$ (0)	$ (0)	$ (0)
A4 - Residential Behavior	**$ 56**	*$ 51*	*$ 64*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Residential	**$ 1,855**	*$ 1,549*	*$ 2,039*	**$ 0**	**$ -**	**$ 0**	**$ 0**	**$ -**	**$ 3**	**$ 3**	**$ 5**	**$ 5**
Commercial/Industrial Programs												
C1 - Large Business Energy Solutions	**$ 1,922**	*$ 1,607*	*$ 2,163*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
C2 - Small Business Energy Solutions	**$ 1,541**	*$ 1,184*	*$ 1,718*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
C3 - Municipal Energy Solutions												
Sub-Total Commercial & Industrial	**$ 3,463**	*$ 2,791*	*$ 3,881*	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total	**$ 5,318**	*$ 4,340*	*$ 5,920*	**$ 0**	**$ -**	**$ 0**	**$ 0**	**$ -**	**$ 3**	**$ 3**	**$ 5**	**$ 5**

	Resource Benefits ($000)							Non-Resource Benefits ($000)			Environ-mental Benefits ($000)
	Electric		Gas Benefit								
	Electric DRIPE	Total Electric Benefit	Gas Benefit	Gas DRIPE	Total Gas Benefit	Water Benefit	Total Resource Benefits	Fossil Emissions	Other Non-Resource Benefits	Total Non-Resource Benefits	
Residential Programs											
B1 - Home Energy Assistance	$ 1	**$ 12**	$ 391	$ 7	$ 397	$ -	**$ 409**	$ 75	$ -	**$ 75**	**$ 8**
A1 - Energy Star Homes	$ -	**$ -**	$ 509	$ 8	$ 516	$ -	**$ 516**	$ 104	$ 77	**$ 182**	**$ -**
A2 - Home Performance with Energy Star	$ 0	**$ 6**	$ 314	$ 5	$ 320	$ 1	**$ 326**	$ 60	$ 49	**$ 109**	**$ 3**
A3 - Energy Star Products	$ 0	**$ (0)**	$ 259	$ 5	$ 264	$ -	**$ 264**	$ 44	$ 40	**$ 84**	**$ (0)**
A4 - Residential Behavior	$ -	**$ -**	$ 49	$ 2	$ 51	$ -	**$ 51**	$ 5	$ 8	**$ 13**	**$ -**
Sub-Total Residential	**$ 1**	**$ 17**	**$ 1,522**	**$ 27**	**$ 1,549**	**$ 1**	**$ 1,567**	**$ 288**	**$ 173**	**$ 462**	**$ 10**
Commercial/Industrial Programs											
C1 - Large Business Energy Solutions	$ -	**$ -**	$ 1,570	$ 36	$ 1,607	$ 24	**$ 1,631**	$ 291	$ 241	**$ 532**	**$ -**
C2 - Small Business Energy Solutions	$ -	**$ -**	$ 1,156	$ 28	$ 1,184	$ 155	**$ 1,340**	$ 201	$ 178	**$ 378**	**$ -**
C3 - Municipal Energy Solutions											
Sub-Total Commercial & Industrial	**$ -**	**$ -**	**$ 2,727**	**$ 64**	**$ 2,791**	**$ 180**	**$ 2,971**	**$ 492**	**$ 419**	**$ 910**	**$ -**
Total	**$ 1**	**$ 17**	**$ 4,249**	**$ 91**	**$ 4,340**	**$ 181**	**$ 4,538**	**$ 780**	**$ 592**	**$ 1,372**	**$ 10**

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(2) Non-resource benefits include NEIs, which are only applied to the Home Energy Asssitance program in the GST primary cost test.
(3) Non-embedded environmental benefits are not included in the GST primary cost test.

Portfolio Planned Versus Actual Performance - 2022

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime MMBtu Savings	716,781	*537,586*		-	2.475%	-	$ 68,911	*$ 86,139*	$ -	Planned and Actual from Cost Eff Tab
2	Annual MMBtu Savings	50,149	*37,612*		-	1.100%	-	$ 30,627	*$ 38,284*	$ -	Planned and Actual from Cost Eff Tab
3	Total Resource Benefits	5,422,022	*3,524,315*		-		-			$ -	Planned and Actual from Cost Eff Tab
4	Total Utility Costs[1]	2,784,298	*1,809,793*		-		-			$ -	Planned and Actual from Cost Eff Tab
5	Net Benefits	2,637,725	*1,714,521*		-	1.925%	-	$ 53,598	*$ 66,997*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total					5.500%	-	**$ 153,136**	***$ 191,420***	$ -	

		Granite State Test		
		Planned	Actual	Source
7	Total Benefits (GST)	$ 6,315,352		Planned and Actual from Cost Eff Tab
8	Performance Incentive	$ 153,136	$ -	
9	Total Utility Costs	$ 2,784,298	$ -	
10	**Portfolio GST BCR**	**2.15**	**-**	

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

Portfolio Planned Versus Actual Performance - 2023

	Portfolio	Planned	Threshold	Actual	% of Plan	Design Coefficient	Actual Coefficient	Planned PI	*125% of Planned PI*	Actual PI	Source
1	Lifetime MMBtu Savings	564,300	*423,225*		-	2.475%	-	$ 59,316	*$ 66,248*	$ -	Planned and Actual from Cost Eff Tab
2	Annual MMBtu Savings	39,465	*29,599*		-	1.100%	-	$ 26,363	*$ 29,443*	$ -	Planned and Actual from Cost Eff Tab
3	Total Resource Benefits	4,537,940	*2,949,661*		-		-			$ -	Planned and Actual from Cost Eff Tab
4	Total Utility Costs[1]	2,396,601			-		-			$ -	Planned and Actual from Cost Eff Tab
5	Net Benefits	2,141,339	*1,391,870*		-	1.925%	-	$ 46,135	*$ 51,526*	$ -	Planned and Actual from ADR Cost Eff Tab
6	Total					5.500%	-	$ 131,813	$ 147,217	$ -	

		Granite State Test		
		Planned	Actual	Source
7	Total Benefits	$ 5,317,738		Planned and Actual from Cost Eff Tab
8	Performance Incentive	$ 131,813	$ -	from row 9 above
9	Total Utility Costs	$ 2,396,601		from row 7 above
10	**Portfolio GST BCR**	-	-	row 10 divided by rows 11+12

Costs, Benefits, and PI Expressed in 2022 Dollars. Nominal PI (2023$) is $136,096.96.

[1] Note that in order to avoid a circular reference in the calculation of performance incentive, "Total Utility Costs" does not include the value of PI.

Program Summary - 2021 - 2023 PLAN

Home Energy Assistance			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
B1a - HEA (Weatherization)	Air Sealing, Gas	G21B1a001	45	38	15	15	100%	100%	100%	100%	91%	91%	737	622	11,057	9,337
B1a - HEA (Weatherization)	Faucet Aerator, Gas	G21B1a002	-	-	7	7	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Hand Held Showerhead, Gas	G21B1a003	-	-	7	7	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Insulation, Gas	G21B1a004	45	38	25	25	100%	100%	100%	100%	91%	91%	1,638	1,383	40,950	34,580
B1a - HEA (Weatherization)	LED Bulb, General Service Lamps	G21B1a005	-	-	2	2	100%	100%	98%	98%	91%	91%	-	-		
B1a - HEA (Weatherization)	LED Bulb, Linear	G21B1a006	-	-	10	10	100%	100%	98%	98%	91%	91%	-	-		
B1a - HEA (Weatherization)	LED Bulb, Other Specialty	G21B1a007	-	-	2	2	100%	100%	98%	98%	91%	91%	-	-		
B1a - HEA (Weatherization)	LED Bulb, Reflector	G21B1a008	-	-	2	2	100%	100%	98%	98%	91%	91%	-	-		
B1a - HEA (Weatherization)	LED Fixture	G21B1a009	-	-	2	2	100%	100%	98%	98%	91%	91%	-	-		
B1a - HEA (Weatherization)	Low Flow Showerhead, Gas	G21B1a010	-	-	7	7	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Pipe Insulation - Hot Water, Gas	G21B1a011	-	-	15	15	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Visual Audit	G21B1a012	-	-	1	1	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Baseload Audit - SF	G21B1a013	-	-	1	1	100%	100%	100%	100%	91%	91%	-	-		
B1a - HEA (Weatherization)	Baseload Audit - MF	G21B1a014	-	-	1	1	100%	100%	100%	100%	91%	91%	-	-		
B1b - HEA (HVAC Systems)	Boiler Replacement, Gas	G21B1b001	6	4	19	19	100%	100%	100%	100%	91%	91%	218	146	4,150	2,766
B1b - HEA (HVAC Systems)	Furnace Replacement, Gas	G21B1b002	1	1	17	17	100%	100%	100%	100%	91%	91%	14	14	232	232
B1b - HEA (HVAC Systems)	Programmable Thermostat, Gas	G21B1b003	12	12	15	15	100%	100%	100%	100%	91%	91%	38	38	573	573
B1b - HEA (HVAC Systems)	Wifi Thermostat, Gas	G21B1b004	1	1	15	15	100%	100%	100%	100%	91%	91%	5	5	79	79
Home Energy Assistance Subtotal													**2,651**	**2,208**	**57,041**	**47,568**

Energy Star Homes			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A1a - ES Homes	Cooling, Electric, SF	G21A1a001	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
A1a - ES Homes	Heating, Gas, SF	G21A1a002	64	70	25	25	100%	100%	100%	100%	100%	100%	1,664	1,820	41,600	45,500
A1a - ES Homes	Hot Water, Gas, SF	G21A1a003	50	50	15	15	100%	100%	100%	100%	100%	100%	175	175	2,625	2,625
A1a - ES Homes	Cooling, Electric, MF	G21A1a002	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
A1a - ES Homes	Heating, Gas, MF	G21A1a005	32	36	25	25	100%	100%	100%	100%	100%	100%	504	567	12,600	14,175
A1a - ES Homes	Hot Water, Gas, MF	G21A1a006	25	25	15	15	100%	100%	100%	100%	100%	100%	75	75	1,125	1,125
A1a - ES Homes	LED Bulb	G21A1a007	-	-	5	5	100%	100%	100%	100%	100%	100%	-	-		
A1a - ES Homes	LED Fixture	G21A1a008	-	-	5	5	100%	100%	100%	100%	100%	100%	-	-		
A1a - ES Homes	Clothes Washer	G21A1a009	-	-	11	11	100%	100%	100%	100%	100%	100%	-	-		
A1a - ES Homes	Residential New Construction Code Com	G21A1a010	-	-	-	-	100%	100%	100%	100%	35%	35%	-	-		
	Energy Star Homes Subtotal												**2,418**	**2,637**	**57,950**	**63,425**

Home Performance with Energy Star			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A2a - HPwES (Weatherization)	Air Sealing, Gas	G21A2a001	32	32	15	15	100%	100%	99%	99%	104%	104%	395	395	5,930	5,930
A2a - HPwES (Weatherization)	Faucet Aerator, Gas	G21A2a002	8	8	7	7	100%	100%	99%	99%	104%	104%	1	1	9	9
A2a - HPwES (Weatherization)	Hand Held Showerhead, Gas	G21A2a003	8	8	7	7	100%	100%	99%	99%	104%	100%	5	5	37	35
A2a - HPwES (Weatherization)	Insulation, Gas	G21A2a004	43	44	25	25	100%	100%	99%	99%	104%	104%	1,107	1,133	27,671	28,314
A2a - HPwES (Weatherization)	LED Bulb, General Service Lamps	G21A2a005	-	-	2	2	100%	100%	98%	98%	100%	100%	-	-		
A2a - HPwES (Weatherization)	LED Bulb, Linear	G21A2a006	-	-	10	10	100%	100%	98%	98%	100%	100%	-	-		
A2a - HPwES (Weatherization)	LED Bulb, Other Specialty	G21A2a007	-	-	2	2	100%	100%	98%	98%	100%	100%	-	-		
A2a - HPwES (Weatherization)	LED Bulb, Reflector	G21A2a008	-	-	2	2	100%	100%	98%	98%	100%	100%	-	-		
A2a - HPwES (Weatherization)	LED Fixture	G21A2a009	-	-	2	2	100%	100%	98%	98%	100%	100%	-	-		
A2a - HPwES (Weatherization)	Low Flow Showerhead, Gas	G21A2a010	-	-	7	7	100%	100%	99%	99%	104%	100%	-	-		
A2a - HPwES (Weatherization)	Pipe Insulation - Hot Water, Gas	G21A2a011	-	-	15	15	100%	100%	99%	99%	104%	104%	-	-		
A2a - HPwES (Weatherization)	Baseload Audit - Electric Savings	G21A2a012	-	-	1	1	100%	100%	99%	99%	100%	100%	-	-		
A2a - HPwES (Weatherization)	Baseload Audit - Thermal Savings	G21A2a013	-	-	1	1	100%	100%	99%	99%	100%	100%	-	-		
A2a - HPwES (Weatherization)	Visual Audit	G21A2a014	30	25	1	1	100%	100%	99%	99%	100%	100%	-	-	-	-
			-	-	-	-	0%	100%	0%	99%	0%	100%	-	-		
A2b - HPwES (HVAC Systems)	Boiler Replacement, Gas	G21A2b001	-	-	19	19	100%	100%	99%	99%	100%	100%	-	-		
A2b - HPwES (HVAC Systems)	Furnace Replacement, Gas	G21A2b002	-	-	17	17	100%	100%	99%	99%	100%	100%	-	-		
A2b - HPwES (HVAC Systems)	Programmable Thermostat, Gas	G21A2b003	65	65	15	15	100%	100%	99%	99%	104%	104%	234	234	3,514	3,514
A2b - HPwES (HVAC Systems)	Wifi Thermostat, Gas	G21A2b004	5	5	15	15	100%	100%	100%	100%	104%	104%	30	30	452	452
	Home Performance with Energy Star Subtotal												**1,773**	**1,799**	**37,612**	**38,255**

Energy Start Appliances			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A3b - ES Appliances	Early Replacement Boiler, FHW - EE 90	G21A3b001	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Early Replacement Boiler, FHW - Retiren	G21A3b002	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Early Replacement Boiler, Steam - EE: 8	G21A3b003	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Early Replacement Boiler, Steam - Retire	G21A3b004	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Boiler Reset Controls	G21A3b005	10	10	15	15	100%	100%	100%	100%	100%	100%	51	51	765	765
A3b - ES Appliances	Condensing Boiler >= 90% AFUE (Up to	G21A3b006	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Condensing Boiler >= 95% AFUE (Up to	G21A3b007	35	35	19	19	100%	100%	100%	100%	100%	100%	518	518	9,842	9,842
A3b - ES Appliances	Furnace 95+ AFUE (<150) w/ECM Motor	G21A3b008	40	40	17	17	100%	100%	100%	100%	100%	100%	392	392	6,664	6,664
A3b - ES Appliances	Furnace 97+ AFUE (<150) w/ECM Motor	G21A3b009	40	40	17	17	100%	100%	100%	100%	100%	100%	412	412	7,004	7,004
A3b - ES Appliances	Heat Recovery Ventilator (-133 kWh pena	G21A3b010	1	1	20	20	100%	100%	100%	100%	100%	100%	8	8	154	154
A3b - ES Appliances	Programmable Thermostat	G21A3b011	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Indirect Water Heater (attached to ES FH	G21A3b012	-	-	20	20	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Integrated Water Heater w/Condensing B	G21A3b013	1	1	19	19	100%	100%	100%	100%	100%	100%	8	8	160	160
A3b - ES Appliances	Integrated Water Heater w/Condensing B	G21A3b014	23	15	19	19	100%	100%	100%	100%	100%	100%	294	192	5,594	3,648
A3b - ES Appliances	Condensing Water Heater (EF 0.95)	G21A3b015	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Stand Alone Storage Tank Water Heater	G21A3b016	-	-	13	13	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Tankless On-Demand Water Heater, >=	G21A3b017	-	-	19	19	100%	100%	100%	100%	100%	100%	-	-		
A3b - ES Appliances	Tankless On-Demand Water Heater, >=	G21A3b018	15	15	19	19	100%	100%	100%	100%	100%	100%	110	110	2,081	2,081
A3b - ES Appliances	WiFi Thermostat (Heating Only)	G21A3b019	10	10	15	15	100%	100%	100%	100%	100%	100%	58	58	870	870
A3b - ES Appliances	WiFi Thermostat (Heating & Cooling)	G21A3b020	15	15	15	15	100%	100%	100%	100%	100%	100%	87.0	87.0	1,305.0	1,305.0
	Energy Star Appliances Subtotal												**1,938**	**1,836**	**34,438**	**32,492**

Home Energy Reports			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
A4a - Residential Behavior	Home Energy Reports	G21A4a001	11,200	11,200	1	1	100%	100%	100%	100%	100%	100%	5,847	5,847	5,847	5,847
		Home Energy Reports Subtotal											**5,847**	**5,847**	**5,847**	**5,847**

Large Commercial and Industrial			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C1a - LCI Retrofit	Custom Large Hot Water Retro	G21C1a001	-	-	10	10	100%	100%	100%	100%	87%	87%	-	-		
C1a - LCI Retrofit	Custom Large HVAC Retro	G21C1a002	7	6	20	20	100%	100%	100%	100%	87%	87%	4,263	3,654	85,260	73,080
C1a - LCI Retrofit	Custom Large Other Retro	G21C1a003	9	5	13	13	100%	100%	100%	100%	87%	87%	4,307	2,393	55,985	31,103
C1a - LCI Retrofit	Custom Large Process Retro	G21C1a004	5	3	13	13	100%	100%	100%	100%	87%	87%	8,700	3,915	113,100	50,895
C1a - LCI Retrofit	Faucet Aerator, Gas	G21C1a005	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Low Flow Showerhead With Thermostati	G21C1a006	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Low Flow Showerhead, Gas	G21C1a007	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Pipe Wrap - Hot Water, Gas	G21C1a008	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Pre Rinse Spray Valve, Gas	G21C1a009	-	-	8	8	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Boiler Reset Controls, Gas	G21C1a010	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Boiler Tune-Ups	G21C1a011	-	-	1	1	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Energy Management System, Gas	G21C1a012	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Pipe Insulation - Heating, Gas	G21C1a013	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Steam Trap, Gas	G21C1a014	-	-	6	6	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	Programmable Thermostat, Gas	G21C1a015	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C1a - LCI Retrofit	WiFi Thermostat (Heating & Cooling)	G21C1a016	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Custom Large Hot Water New	G21C1b001	3	3	10	10	100%	100%	100%	100%	87%	87%	205	205	2,051	2,051
C1b - LCI New Equipment and Con	Custom Large HVAC New	G21C1b002	2	2	18	18	100%	100%	100%	100%	87%	87%	1,044	1,044	18,792	18,792
C1b - LCI New Equipment and Con	Custom Large Other New	G21C1b003	2	2	13	13	100%	100%	100%	100%	87%	87%	992	992	12,893	12,893
C1b - LCI New Equipment and Con	Custom Large Process New	G21C1b004	-	-	13	13	100%	100%	100%	100%	87%	87%	-	-		
C1b - LCI New Equipment and Con	Boiler 1701 to 2000 MBH 90 AFUE, Gas	G21C1b005	3	2	25	25	100%	100%	100%	100%	100%	100%	496	331	12,398	8,265
C1b - LCI New Equipment and Con	Boiler 1000 to 1700 MBH 90 AFUE, Gas	G21C1b006	1	1	25	25	100%	100%	100%	100%	100%	100%	95	95	2,363	2,363
C1b - LCI New Equipment and Con	Boiler 500 to 999 MBH 90 AFUE, Gas	G21C1b007	2	1	25	25	100%	100%	100%	100%	100%	100%	103	51	2,570	1,285
C1b - LCI New Equipment and Con	Boiler 301 to 499 MBH 90 AFUE, Gas	G21C1b008	4	4	25	25	100%	100%	100%	100%	100%	100%	112	112	2,800	2,800
C1b - LCI New Equipment and Con	Boiler to 300 MBH 90 AFUE, Gas	G21C1b009	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Boiler to 300 MBH 95 AFUE, Gas	G21C1b010	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Combo Condensing Boiler / Water Heate	G21C1b011	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Combo Furnace / Water Heater, Gas	G21C1b012	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Condensing Unit Heater, Gas	G21C1b013	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Furnace w/ ECM 95 AFUE, Gas	G21C1b014	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Furnace w/ ECM 97 AFUE, Gas	G21C1b015	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Infrared Heater, Gas	G21C1b016	10	10	17	17	100%	100%	100%	100%	100%	100%	120	120	2,040	2,040
C1b - LCI New Equipment and Con	Faucet Aerator, Gas	G21C1b017	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Low Flow Showerhead With Thermostati	G21C1b018	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Low Flow Showerhead, Gas	G21C1b019	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Pre Rinse Spray Valve, Gas	G21C1b020	55	55	8	8	100%	100%	100%	100%	100%	100%	627	627	5,016	5,016
C1b - LCI New Equipment and Con	Combination Oven, Gas	G21C1b021	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Convection Oven, Gas	G21C1b022	1	1	12	12	100%	100%	100%	100%	100%	100%	34	34	406	406
C1b - LCI New Equipment and Con	Conveyor Oven, Gas	G21C1b023	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Fryer, Gas	G21C1b024	7	6	12	12	100%	100%	100%	100%	100%	100%	548	470	6,577	5,638
C1b - LCI New Equipment and Con	Griddle, Gas	G21C1b025	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Rack Oven, Gas	G21C1b026	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	Steam Cooker, Gas	G21C1b027	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C1b - LCI New Equipment and Con	C&I Large New Construction Code Comp	G21C1b028	1	1	20	20	100%	100%	100%	100%	100%	36%	-	-	-	-
C1c - LCI Midstream	Midstream Water Heater, Condensing Ga	G21C1c012	1	1	15	15	30%	30%	100%	100%	0%	100%	-	9	-	133
C1c - LCI Midstream	Midstream Combination Oven, Gas	G21C1c001	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Convection Oven, Gas	G21C1c002	1	1	12	12	83%	83%	100%	100%	100%	100%	30	30	357	357
C1c - LCI Midstream	Midstream Conveyor Oven, Gas	G21C1c003	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Fryer, Gas	G21C1c004	1	1	12	12	83%	83%	100%	100%	100%	100%	64	64	771	771
C1c - LCI Midstream	Midstream Griddle, Gas	G21C1c005	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Pre-Rinse Spray Valve, Gas	G21C1c006	-	-	8	8	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Rack Oven, Gas	G21C1c007	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Steam Cooker, Gas	G21C1c008	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C1c - LCI Midstream	Midstream Indirect Water Heater, Gas	G21C1c009	1	1	15	15	30%	30%	100%	100%	100%	100%	6	6	84	84
C1c - LCI Midstream	Midstream On Demand Tankless Water H	G21C1c010	1	1	20	20	60%	60%	100%	100%	100%	100%	5	5	105	105
C1c - LCI Midstream	Midstream Volume Water Heater, Gas	G21C1c011	1	1	15	15	60%	60%	100%	100%	100%	100%	153	153	2,290	2,290
	Large Commercial & Industrial Subtotal												**21,902**	**14,308**	**325,856**	**220,366**

Small Commercial and Industrial			Quantity		Measure Life		Net to Gross		In Service Rate		Non-Electric Realization Rate		Net Annual MMBtu Savings		Net Lifetime MMBtu Savings	
Subprogram	Measure	Measure ID	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
C2a - SCI Retrofit	Custom Small Hot Water Retro	G21C2a001	-	-	10	10	100%	100%	100%	100%	87%	87%	-	-		
C2a - SCI Retrofit	Custom Small HVAC Retro	G21C2a002	12	8	14	14	100%	100%	100%	100%	87%	87%	5,220	3,480	73,080	48,720
C2a - SCI Retrofit	Custom Small Other Retro	G21C2a003	10	5	15	15	100%	100%	100%	100%	87%	87%	-	-	-	-
C2a - SCI Retrofit	Custom Small Process Retro	G21C2a004	8	4	20	20	100%	100%	100%	100%	87%	87%	487	244	9,744	4,872
C2a - SCI Retrofit	Faucet Aerator, Gas	G21C2a005	50	50	7	7	100%	100%	100%	100%	100%	100%	85	85	595	595
C2a - SCI Retrofit	Low Flow Showerhead With Thermostati	G21C2a006	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Low Flow Showerhead, Gas	G21C2a007	50	50	7	7	100%	100%	100%	100%	100%	100%	133	133	928	928
C2a - SCI Retrofit	Pipe Wrap - Hot Water, Gas	G21C2a008	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Pre Rinse Spray Valve, Gas	G21C2a009	-	-	8	8	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Boiler Reset Controls, Gas	G21C2a010	30	30	15	15	100%	100%	100%	100%	100%	100%	1,065	1,065	15,975	15,975
C2a - SCI Retrofit	Boiler Tune-Ups	G21C2a011	-	-	-	-	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Energy Management System, Gas	G21C2a012	-	-	-	-	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Pipe Insulation - Heating, Gas	G21C2a013	-	-	15	15	100%	100%	100%	100%	100%	100%	-	-		
C2a - SCI Retrofit	Steam Trap, Gas	G21C2a014	15	15	6	6	100%	100%	100%	100%	100%	100%	126	126	756	756
C2a - SCI Retrofit	Programmable Thermostat, Gas	G21C2a015	60	75	15	15	100%	100%	100%	100%	100%	100%	210	263	3,150	3,938
C2a - SCI Retrofit	WiFi Thermostat (Heating & Cooling)	G21C2a016	-	-	-	-	0%	100%	0%	100%	0%	100%	-	-		
C2b - SCI New Equipment and Con	Custom Small Hot Water New	G21C2b001	16	12	12	12	100%	100%	100%	100%	87%	87%	593	445	7,120	5,340
C2b - SCI New Equipment and Con	Custom Small HVAC New	G21C2b002	7	5	14	14	100%	100%	100%	100%	87%	87%	1,989	1,421	27,843	19,888
C2b - SCI New Equipment and Con	Custom Small Other New	G21C2b003	-	-	-	-	100%	100%	100%	100%	87%	87%	-	-		
C2b - SCI New Equipment and Con	Custom Small Process New	G21C2b004	-	-	-	-	100%	100%	100%	100%	87%	87%	-	-		
C2b - SCI New Equipment and Con	Boiler 1701 to 2000 MBH 90 AFUE, Gas	G21C2b005	1	1	25	25	100%	100%	100%	100%	100%	100%	165	165	4,133	4,133
C2b - SCI New Equipment and Con	Boiler 1000 to 1700 MBH 90 AFUE, Gas	G21C2b006	2	2	25	25	100%	100%	100%	100%	100%	100%	189	189	4,725	4,725
C2b - SCI New Equipment and Con	Boiler 500 to 999 MBH 90 AFUE, Gas	G21C2b007	5	4	25	25	100%	100%	100%	100%	100%	100%	257	206	6,425	5,140
C2b - SCI New Equipment and Con	Boiler 301 to 499 MBH 90 AFUE, Gas	G21C2b008	5	4	25	25	100%	100%	100%	100%	100%	100%	140	112	3,500	2,800
C2b - SCI New Equipment and Con	Boiler to 300 MBH 90 AFUE, Gas	G21C2b009	5	5	25	25	100%	100%	100%	100%	100%	100%	74	74	1,838	1,838
C2b - SCI New Equipment and Con	Boiler to 300 MBH 95 AFUE, Gas	G21C2b010	10	8	25	25	100%	100%	100%	100%	100%	100%	177	142	4,425	3,540
C2b - SCI New Equipment and Con	Combo Condensing Boiler / Water Heate	G21C2b011	-	-	25	25	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Combo Furnace / Water Heater, Gas	G21C2b012	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Condensing Unit Heater, Gas	G21C2b013	2	2	18	18	100%	100%	100%	100%	100%	100%	82	82	1,472	1,472
C2b - SCI New Equipment and Con	Furnace w/ ECM 95 AFUE, Gas	G21C2b014	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Furnace w/ ECM 97 AFUE, Gas	G21C2b015	-	-	18	18	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Infrared Heater, Gas	G21C2b016	10	10	17	17	100%	100%	100%	100%	100%	100%	120	120	2,040	2,040
C2b - SCI New Equipment and Con	Faucet Aerator, Gas	G21C2b017	130	130	10	10	100%	100%	100%	100%	100%	100%	221	221	2,210	2,210
C2b - SCI New Equipment and Con	Low Flow Showerhead With Thermostati	G21C2b018	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Low Flow Showerhead, Gas	G21C2b019	-	-	7	7	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Pre Rinse Spray Valve, Gas	G21C2b020	-	-	8	8	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Combination Oven, Gas	G21C2b021	5	5	12	12	100%	100%	100%	100%	100%	100%	561	561	6,726	6,726
C2b - SCI New Equipment and Con	Convection Oven, Gas	G21C2b022	2	2	12	12	100%	100%	100%	100%	100%	100%	68	68	811	811
C2b - SCI New Equipment and Con	Conveyor Oven, Gas	G21C2b023	-	-	12	12	100%	100%	100%	100%	100%	100%	-	-		
C2b - SCI New Equipment and Con	Fryer, Gas	G21C2b024	5	5	12	12	100%	100%	100%	100%	100%	100%	392	392	4,698	4,698
C2b - SCI New Equipment and Con	Griddle, Gas	G21C2b025	3	3	12	12	100%	100%	100%	100%	100%	100%	114	114	1,364	1,364
C2b - SCI New Equipment and Con	Rack Oven, Gas	G21C2b026	2	2	12	12	100%	100%	100%	100%	100%	100%	423	423	5,071	5,071
C2b - SCI New Equipment and Con	Steam Cooker, Gas	G21C2b027	1	1	12	12	100%	100%	100%	100%	100%	100%	371	371	4,448	4,448
C2b - SCI New Equipment and Con	C&I Small New Construction Code Comp	G21C2b028	-	-	20	20	100%	100%	100%	100%	100%	36%	-	-		
C2c - SCI Midstream	Midstream Combination Oven, Gas	G21C2c001	1	1	12	12	83%	83%	100%	100%	100%	100%	93	93	1,121	1,121
C2c - SCI Midstream	Midstream Convection Oven, Gas	G21C2c002	1	1	12	12	83%	83%	100%	100%	100%	100%	30	30	357	357
C2c - SCI Midstream	Midstream Conveyor Oven, Gas	G21C2c003	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C2c - SCI Midstream	Midstream Fryer, Gas	G21C2c004	2	2	12	12	83%	83%	100%	100%	100%	100%	130	130	1,565	1,565
C2c - SCI Midstream	Midstream Griddle, Gas	G21C2c005	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C2c - SCI Midstream	Midstream Pre-Rinse Spray Valve, Gas	G21C2c006	-	-	8	8	83%	83%	100%	100%	100%	100%	-	-		
C2c - SCI Midstream	Midstream Rack Oven, Gas	G21C2c007	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C2c - SCI Midstream	Midstream Steam Cooker, Gas	G21C2c008	-	-	12	12	83%	83%	100%	100%	100%	100%	-	-		
C2c - SCI Midstream	Midstream Indirect Water Heater, Gas	G21C2c009	2	1	15	15	30%	30%	100%	100%	100%	100%	11	6	171	86
C2c - SCI Midstream	Midstream On Demand Tankless Water H	G21C2c010	3	3	20	20	60%	60%	100%	100%	100%	100%	16	16	320	320
C2c - SCI Midstream	Midstream Volume Water Heater, Gas	G21C2c011	1	1	15	15	60%	60%	100%	100%	100%	100%	49	49	736	736
C2c - SCI Midstream	Midstream Water Heater, Condensing Ga	G21C2c012	1	1	15	15	30%	30%	100%	100%	100%	100%	9	9	135	135
	Small Commercial & Industrial Subtotal												**13,598**	**10,830**	**197,483**	**156,348**

THE STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY OF

MARISA B. PARUTA

PROPOSED 2022-2023 SYSTEM BENEFITS CHARGE RATE CHANGE

Docket No. DE 20-092

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, by whom you are employed and in what capacity.

A. My name is Marisa B. Paruta. I am employed by Eversource Energy Service Company as the Director of Revenue Requirements for Connecticut and New Hampshire. My primary responsibilities are supporting the coordination and implementation of revenue requirements calculations for Eversource in New Hampshire.

Q. Have you previously testified before the Commission?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is: (1) to present and support the calculation of the Energy Efficiency ("EE") component of the System Benefits Charge ("SBC") proposed for effect March 1, 2022, and January 1, 2023; and (2) to present and support the calculation of the lost base revenue ("LBR") component of the SBC proposed for effect May 1, 2022. My testimony explains what is contained in Attachment E3, which provides the calculations of the EE and LBR rate components of the SBC for Eversource. The testimony provides a detailed explanation of the changes made for the LBR rate component effective May 1, 2022 and January 1, 2023 in order to address the passage of HB 549 into law on February 24, 2022, amending RSA 374-F:3, VI ("HB 549").

II. EE COMPONENT OF THE SBC

Q. What is the proposed EE Component of the SBC?

A. The proposed statewide EE rate for effect on March 1, 2022 is $0.00528 per kWh and is estimated to be $0.00543 per kWh for effect on January 1, 2023. In accordance with HB549, the EE portion of the SBC resets to the 2020/2021 level for 2022, and for 2023, the EE portion of the SBC is "calculated using the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States Department of Labor plus 0.25 percent [adder to account for inflation] all as calculated by the department of energy."[1] The estimated rate for effect on January 1, 2023 will be updated on December 1, 2022 to account for any over or under collections and to incorporate the inflation adder, in accordance with HB 549.

Q. How was the EE rate calculated?

A. The EE portion of the SBC rate was set by HB 549 - explicitly for 2022, and then using the 2022 rate and adjusting it as discussed above for 2023. Pages 2 and 3 of Attachment

[1] House Bill 549, *An Act Relative to the System Benefits Charge and the Energy Efficiency and Sustainable Energy Board,* signed into law by the Governor on February 24, 2022.

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E3 provides the forecasted revenues and expenses and a preliminary reconciliation of the EE component of the SBC rate for 2022 and 2023.

III. LBR COMPONENT OF THE SBC

Q. What is the proposed LBR Component of the SBC?

A. Eversource's LBR rate has remained constant since January 1, 2020. As part of this SBC rate filing, the Company includes the preliminary 2021 LBR under recovery amount of $3,054 thousand[2] in the setting of the LBR component of the 2022 rate. This reconciliation calculates any over or under collection of revenues that occur as a result of differences between the actual revenues collected from the LBR rate set on January 1, 2020 and the preliminary calculated lost revenues for calendar year 2021. The over or under collections result from variances in, 1) actual sales volumes, as compared to the forecasted sales volumes, and 2) actual measure savings, as compared to the forecasted measure savings used to establish the LBR rate in 2020. Eversource is truing up LBR rates at this time under the direction of HB 549, which states, "the joint utility energy efficiency plan and programming framework and components, including utility performance incentive payments, lost base revenue calculations, and Evaluation, Measurement, and Verification process that were in effect on January 1, 2021, shall remain in effect until changed by an order or operation of law as authorized in subparagraphs (3) and (5)." Therefore, Eversource provides the following proposed LBR

[2] Attachment E3, Page 7, Line 4, Col. B

rates, consistent with this direction: $0.00185 per kWh for 2022 and $0.00205 per kWh for 2023.

Q. How was the LBR rate calculated?

A. The LBR rate calculations are provided on pages 4 through 8 of Attachment E3.

- Page 4 provides a summary of the LBR component of the SBC rate for 2022 and 2023 and includes the sum of the forecasted lost base revenue, the prior year carryover balance with interest, and the current year interest. The total amount is then divided by the forecasted deliveries to arrive at the proposed LBR component of the SBC rate.
- Pages 5 and 6 provide the supporting forecasted savings calculations for the 2022 and 2023 lost base revenues, respectively.
- Pages 7 and 8 provide forecasted reconciliations of monthly revenues collected from the LBR rate and estimated lost base revenues for 2022 and 2023, respectively.
- Page 9 provides a computation of the average sector distribution rates for use in the lost base revenue calculation.
- Page 10 provides the total SBC rate bill impacts for 2022 and 2023, as compared to current rates in effect February 1, 2022.
- Pages 11 and 12 provide additional details supporting the average rate calculation.

Q. Are there changes in the way that LBR is calculated in 2022 and 2023?

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A. LBR for 2022 and 2023 was calculated consistent with the way LBR was calculated and implemented on January 1, 2021, as directed by HB 549 and pursuant to the final working group report on LBR issued August 29, 2018[3], so there are no changes to the manner in which calculations are performed for these years. As demonstrated on Pages 5 and 6 of Attachment E3, measures installed after 2018 have their LBR calculated by adding two "separate" calculations: (1) the kWh savings are multiplied by the sector's kWh LBR Average Distribution Rate ("ADR"); and (2) the kW savings are multiplied by the sector's kW LBR ADR. The sum of these two calculations results in the total LBR for measures installed. For all measures installed on or after January 1, 2019, this method is used to calculate LBR for the life of the measure.

Q. Please describe how kWh savings are derived for the first month of a new measure's installation.

A. Consistent with section III and IV and Appendix A and B of the EERS Working Group Report on LBR, when calculating forecasted savings, a 50 percent factor is applied to reflect that installations occur across any given month rather than all occurring on the first of the month. When calculating actual savings in the calendar year reconciliation, the 50 percent convention is not used to reflect the full annual savings for the measures.

[3] EERS Working Group Report on LBR (August 29, 2018)

Q. Please describe how Eversource has accounted for 2018 test year savings from the most recently approved rate case in Docket No. DE 19-057, within the calculation of LBR.

A. Consistent with the Settlement Agreement approved by the New Hampshire Public Utilities Commission in Docket No. DE 19-057 on December 15, 2020 (Order No. 26,433), measures installed prior to the 2018 test year were incorporated into the cost of service and revenue requirement and therefore are not included in the calculation of LBR savings. For measures installed during the 2018 test year, those savings were not fully recognized in 2018 and the residual savings that were not recognized in the test year were not incorporated into the revenue requirement. Those residual savings not fully recognized in 2018 are what comprise the 2018 savings and LBR calculations. Those savings that were fully recognized in 2018 were part of the test year cost of service and revenue requirement.

Q. Please describe the derivation of the Average Distribution Rates used in the calculation of LBR.

A. Consistent with section V of the EERS Working Group Report, the ADR used in the forecasted LBR calculations for 2022 and 2023 utilize the current distribution rates in effect using billing determinants for the 12-month period ending December 31, 2021. The ADR used in the LBR preliminary reconciliation calculation for 2021 utilizes the distribution rates in effect during the 2021 period using billing determinants for the 12-month period ending December 31, 2021.

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Q. Please describe how Eversource has accounted for retirements in the calculation of LBR.

A. Consistent with sections III.F and IV.F. of the EERS Working Group Report, any savings associated with measures that are retiring within the calendar year are removed from the LBR calculation. A separate line showing retired measures is provided in the schedules supporting the LBR calculation.

Q. Please explain why the 2021 LBR reconciliation is considered a preliminary calculation.

A. The 2021 LBR reconciliation is a preliminary reconciliation because the 2021 savings have not been finalized at the time of this filing. The final reconciliation of the 2021 LBR and any resulting over or under recoveries will be calculated in the 2021 annual performance filing made on June 1, 2022. Any over or under recoveries will be incorporated into the 2023 LBR rate setting filed on July 1, 2022. A carrying charge is applied to the cumulative over or under recovery balance on a monthly basis using the Prime Rate.

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IV. TOTAL SBC AND BILL IMPACTS

Q. What is the total proposed SBC rate?

A. As shown on Page 1 of Attachment E3, which provides a summary of the calculation of the SBC rate, the total proposed SBC rate is $0.00863 per kWh. The SBC consists of the

EE and LBR rate components discussed above, as well as the Electric Assistance Program ("EAP") rate component of $0.00150 per kWh, which remains unchanged as of the date of this filing.

Q. Have you provided bill impacts associated with the proposed SBC?

A. Yes. The bill impacts for a typical residential and C&I customer are provided on Page 10 of Attachment E3. The bill impacts for the years 2022 and 2023 are measured against the current rates in effect as of February 1, 2022.

Q. Does the Company require Commission approval of the SBC billed to customers by a specific date?

A. Yes, according to HB 549, the Commission must issue a decision on the proposed 2022-2023 plan in time for programs and rates to be effective May 1, 2022, otherwise the plan will be deemed automatically approved. While HB 549 still requires a Commission order for adjustments to LBR and has no automatic approval provision, the Company respectfully requests that the Commission approve the proposed 2022-2023 plan and LBR rates in an order prior to May 1, 2022 so that a complete updated SBC rate can be implemented prior to the effective date of May 1, 2022.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 20-092

Electric and Gas Utilities

2022–2023 Triennial Energy Efficiency Plan
System Benefits Charge

DIRECT TESTIMONY

OF

HEATHER TEBBETTS

ATTACHMENT K

March 1, 2022

Liberty™

I. INTRODUCTION AND BACKGROUND

Q. Please state your full name, business address, and position.

A. My name is Heather M. Tebbetts and my business address is 9 Lowell Road, Salem, New Hampshire. I am Manager of Rates and Regulatory Affairs for Liberty Utilities Service Corp.

Q. On whose behalf are you appearing?

A. On behalf of Liberty Utilities (Granite State Electric) Corp. ("Granite State") and Liberty Utilities (EnergyNorth Natural Gas) Corp. ("EnergyNorth") (collectively "Liberty" or "the Companies").

Q. Please describe your educational background and training.

A. I graduated from Franklin Pierce University in 2004 with a Bachelor of Science degree in Finance. I received a Master of Business Administration from Southern New Hampshire University in 2007.

Q. Please describe your professional background.

A. I joined LUSC in October 2014. Prior to my employment at LUSC, I was employed by Public Service Company of New Hampshire ("PSNH") as a Senior Analyst in NH Revenue Requirements from 2010 to 2014. Prior to my position in NH Revenue Requirements, I was a Staff Accountant in PSNH's Property Tax group from 2007 to 2010 and a Customer Service Representative III in PSNH's Customer Service Department from 2004 to 2007.

Q. Have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support the calculation of the annual rates for Energy Efficiency ("EE") and Lost Base Revenue ("LBR") components of the System Benefits Charge ("SBC") for Granite State. I also explain how each rate was derived and provide additional, related information regarding bill impacts, the reconciliation of 2021 energy efficiency program revenues and costs, and a forecast of 2022 energy efficiency revenue and costs.

III. BACKGROUND

Q. Why are the Companies proposing new SBC and LBR rates at this time?

A. On September 1, 2020, the Companies, along with the New Hampshire Electric Cooperative, Inc., Public Service Company of New Hampshire d/b/a Eversource Energy, Unitil Energy Systems, Inc., and Northern Utilities (collectively, the "Joint Utilities") filed a triennial EE plan for approval by the Commission that included, among other things, updated SBC rates designed to fund New Hampshire's EE programs for the period 2021 through 2023. In Order No. 26,553 (Nov. 12, 2021) the Commission rejected the plan and proposed rates and set SBC rates at historical levels.[1] On February 24, 2022,

1 "[T]he Commission authorizes energy efficiency program spending at an overall level consistent with the 2018–20 Plan." Order No. 26,553 at 36.

the Governor signed House Bill 549, which established a new method for setting SBC rates, which has been codified at RSA 374-F:3, VI-a(d)(2) (referred to here as "HB 549"). The rates I propose below are consistent with the requirements of HB 549.

Q. Please summarize briefly the requirements established by HB 549.

A. The new legislation sets funding for EE based on 2020 levels with subsequent adjustments beginning January 1, 2023, which will be calculated based on inflation data, calculated by using the most recently available 3-year average of the consumer price index for wage earners (CPI-W[2]) as published by the United States Department of Labor, Bureau of Labor Statistics, plus 0.25 percent, all as calculated by the New Hampshire Department of Energy. HB 549 also establishes a mechanism to reconcile over- and under-collections that requires the New Hampshire utilities to submit a filing to the Commission each December in which they summarize their variances and propose rate changes to reconcile the differences. The Joint Utilities will submit tariff amendments altering solely the electric utilities' SBC rate and the gas utilities' local delivery adjustment charge ("LDAC") reconciled for over and under collections already occurred, for effect each December 1 for the following year.

2 https://www.bls.gov/opub/btn/volume-3/why-does-bls-provide-both-the-cpi-w-and-cpi-u.htm#_edn1

IV. PROPOSED LBR RATE

Q. What are the components of the SBC?

A. There are three components to the SBC: the energy efficiency funding (the "EE rate"), the low-income funding which rates are set in statute, and lost base revenue ("LBR") collections.

Q. What component of the SBC are you proposing to change?

A. The Company is proposing to collect its LBR for 2019 and 2020, which has not previously been included in the SBC.

Q. Is the new EE rate in effect now?

A. Yes. The Commission's Order No. 26,579 (Feb. 10, 2022) required that the Joint Utilities update their rates "as soon as practicable."[3] Granite State implemented the new EE rate effective as of March 1, 2022, and the Company is now proposing to collect the LBR component effective May 1, 2022.

Q. Does the Company have a preliminary energy efficiency rate for January 1, 2023?

A. Yes. The preliminary statewide EE portion of the SBC rate is estimated to be $0.00543 per kWh for effect on January 1, 2023.

Q. How was the rate calculated?

A. The rate was calculated using the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States

3 Order No. 26,579 page 5

Department of Labor plus 0.25 percent [to account for inflation] all as calculated by the Department of Energy ("DOE"), both in accordance with HB 549. The estimated rate for effect January 1, 2023, will be updated by December 1, 2022, to account for any over or under collections and to incorporate the inflation calculation in accordance with HB 549.

V. <u>UPDATED LBR RATES</u>

Q. What is the LBR rate?

A. The LBR rate is a mechanism that allows the utilities to recover their lost revenue resulting from the installation of Commission-approved energy efficiency measures beginning on January 1, 2017, as approved in Docket No. DE 15-137 by Order No. 25,932 (Aug. 2, 2016). The settling parties in that docket agreed, and the Commission approved, that the LBR for each utility will cease when a new revenue decoupling mechanism is implemented. Order No. 25,932 at 60. Granite State implemented decoupling as of July 1, 2021, and thus the need for the LBR mechanism ceased as of that date.

Q. What period is your proposed LBR rate based on?

A. 2019 and 2020.

Q. Is the LBR rate also affected by HB 549?

A. No.

Q. Then why is the Company proposing a new LBR rate at this time, particularly to recover lost base revenues from the past?

A. Granite State first sought recovery of these costs in September 2019 as part of the 2020 update to the 2018–2020 EE Plan, when it requested an update to the SBC to include the LBR for 2019 and a forecast for 2020. The Commission determined that the parties to that proceeding had not been given sufficient time to conduct discovery on Granite State's request and, accordingly, approved an SBC that excluded the LBR.[4] Granite State subsequently met with the parties to answer any questions about the calculations embedded in that filing and then included a similar proposal to recover 2019 and 2020 LBR costs as part of its 2021–2023 Triennial EE plan filed by the Joint Utilities in this docket in September 2020.[5] The Commission's November 2021 rejection of that EE plan included rejection of Granite State's proposed LBR. This filing is the earliest opportunity for Granite to again seek recovery of the outstanding LBR balances.

Q. How much is Granite State seeking to recover for 2019 and 2020?

A. The Company is seeking to recover $710,104. That figure is made up of cumulative kWh and kW savings from 2019 and 2020, along with an under recovery from 2019 due to lower than anticipated sales in 2019.

Q. Over what period does Granite State propose to recover this amount?

A. May 1 through December 31, 2022.

4 Order No. 26,323 (Dec. 31, 2019).
5 *See* 2021–2023 Triennial Plan filed in this docket on September 1, 2020, Exhibit 1 at Bates 720.

Q. Why did Granite State choose the period over which to recover the LBR revenues?

A. The calculation of LBR costs and their recovery has been set on an annual basis. To continue that practice so a reconciliation may be made to the January 1, 2023, SBC rate change for EE funding, the Company is requesting to recover the balance from May 1 through December 31, 2022.

Q. What rate does Granite State propose to put in effect during that time?

A. The proposed LBR component of the SBC, which totals $0.00114 cents per kWh.

Q. Please explain how you calculated that rate.

A. The total amount of the balance to be recovered for 2019 and 2020 is $710,104. To arrive at the rate, I took that total recovery amount and divided by the total kWh forecasted for the May 1 to December 31 period of 622,136,472. My calculations are summarized and also detailed in Attachment F3.

Table 1. Derivation of Proposed LBR Rate

Cumulative Balance	$710,104
Forecast consumption	622,136,472
Proposed LBR rate	$0.00114/kWh

Q. Will that amount be subject to later reconciliation?

A. Yes, the Company will reconcile the amount collected against the amount owed when the Company files for the 2023 SBC rate change. That rate change will incorporate the reconciled LBR amount.

Q. Will Granite State be seeking recovery of LBR revenues for 2021?

A. Yes, but only for the first half of the year. In Docket No. DE 19-064, Granite State's most recent rate case, the Commission approved the Settlement Agreement that provided for the Company to implement its decoupling mechanism as of July 1, 2021. *See* Order No. 26,376 at 9 (June 30, 2020). As such, the Company is including LBR for the first six months of 2021 prior to implementation of decoupling (i.e., January through June).

Q. Why are the lost revenues from 2021 not included in your current LBR request?

A. The request from the 2019 filing provided for recovery of LBR for 2019 and 2020 and, given that those years have not been recovered, the Company will seek recovery of the 2021 cumulative LBR in its reconciliation of the SBC for December 1, 2022, which will break up the recovery amounts.

Q. What is the estimated LBR amount the Company will for recovery for 2023?

A. The Company has not estimated the amount of LBR to be recovered for 2023 at this time.

VI. LDAC

Q. Is the Company requesting a change to the LDAC rate at this time?

A. No. Consistent with Order No. 26,306 dated October 31, 2019, in Docket No. DG 19-145 and HB 549, the LDAC rate for energy efficiency funding be set at $0.0640 per therm for residential customers and $0.0426 per therm for commercial customers. EnergyNorth does not collect LBR from its customers and as such there is no request for a rate change at this time.

Q. Please explain where the rate change for the LDAC occurs.

A. The LDAC rate is included in the Company's annual Cost of Gas proceeding, filed in September of each year. In that filing, the Company provides the reconciliation of the energy efficiency portion of the LDAC rate. In September 2022, the Company will present a new LDAC rate in accordance with HB 549.

Q. Does the Company have a preliminary energy efficiency rate for January 1, 2023?

A. Yes. The preliminary EE portion of the LDAC rate is estimated to be $0.0658 per therm for residential customers and $0.0438 for commercial customers for effect on January 1, 2023.

Q. How was the rate calculated?

A. The rate was calculated using the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States Department of Labor plus 0.25 percent [to account for inflation] all as calculated by the DOE both in accordance with HB 549. The estimated rate for effect January 1, 2023, will be updated by December 1, 2022, to account for any over or under collections and to incorporate the inflation calculation in accordance with HB 549.

VII. <u>MISCELLANEOUS</u>

Q. What other information is provided in Attachment F3?

A. The following information is provided in Attachment F3:

- Page 1 provides a summary of the energy efficiency budget and rates for 2022;

- Page 2 provides a reconciliation of 2021 energy efficiency funding;
- Page 3 provides a forecast of 2022 energy efficiency funding;
- Page 4 provides the LBR reconciliation;
- Page 5 provides the average distribution rates used to calculate the LBR;
- Page 6 provides bill impacts to residential and commercial customers;
- Pages 7 through 8 provide the rate support to calculate the average distribution rates on page 6; and
- Page 9 provides the summary of LBR

Q. Has the Company provided tariff pages in accordance with Puc 1603.05?

A. Yes, please see the tariff pages associated with the rate changes included at the end of this testimony for Granite State Electric for approval of the LBR.

VIII. BILL IMPACTS

Q. What is the total SBC proposed for May 1, 2022?

A. The total SBC rate proposed for May 1, 2022, is $0.00792 per kWh of which $0.00528 is the EE rate, $0.0015 is the low-income portion, and $0.00114 is the LBR rate.

Q. What are the bill impacts to a residential customer?

A. An average Granite State Electric residential customer using 650 kWh per month will see a bill increase of $0.74 or 0.48% per month.

IX. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

The cost of the Company's (i) Electric Assistance Program and (ii) energy efficiency core programs and any other such energy efficiency programs, as approved by the Commission.

The Company shall implement its Electric Assistance Program as approved by the Commission from time to time. The System Benefits Charge will fund the Company's Electric Assistance Program and such other system benefits as are required by law or approved by the Commission.

The Company will reconcile on an annual basis actual costs incurred of the Electric Assistance Program, including development, implementation, and ongoing administrative and maintenance costs against the actual amounts charged to customers through the portion of the System Benefits Charge attributable to the Electric Assistance Program, set at a level of 0.150¢ per kilowatt-hour in accordance with RSA 374-F:4, VIII (c), and shall be in addition to the portion of the System Benefits Charge relating to the Company's energy efficiency core programs stated below.

The Company shall implement its energy efficiency core programs as approved by the Commission from time to time. The Company's cost of implementing the energy efficiency core programs shall be recovered through the portion of the System Benefits Charge attributable to such programs, set at a level of 0.528¢ per kilowatt-hour in accordance with ~~Order No. 26,579 in Docket No. DE 20-092 Electric and Gas Utilities 2021-2023 New Hampshire Statewide Energy Efficiency Plan,~~ RSA 374-F:3, VI-a(d)(2) which shall be in addition to the portion of the System Benefits Charge relating to the Company's low income customer protection programs stated above. Any difference between the actual energy efficiency funds expended and the funds collected through the System Benefits Charge at 0.528¢ per kilowatt-hour during a calendar year shall, with interest calculated at the average prime rate for each month, be added to or subtracted from the amount to be expended in the following calendar year. If actual amounts are not available for any period, they shall be estimated for purposed of the above calculations and adjusted the following year based on actual data.

The Company shall implement its lost revenue mechanism as approved by the Commission in accordance with Order No. 25,932 in Docket No. DE 15-137 Energy Efficiency Resource Standard, set at a level of 0.114¢. The lost revenue portion of the System Benefits Charge shall be established annually based on a forecast of lost revenue for the prospective year. Any difference between the actual lost revenue and the amount of lost revenue recovered through the System Benefits Charge shall be refunded or recouped with interest during the succeeding year.

Any adjustment of the System Benefits Charge shall be in accordance with a notice filed with the Commission setting forth the amount of the increase or decrease, and the new System Benefits Charge amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Commission may authorize.

The cost of the Company's (i) Electric Assistance Program and (ii) energy efficiency core programs and any other such energy efficiency programs, as approved by the Commission.

The Company shall implement its Electric Assistance Program as approved by the Commission from time to time. The System Benefits Charge will fund the Company's Electric Assistance Program and such other system benefits as are required by law or approved by the Commission.

The Company will reconcile on an annual basis actual costs incurred of the Electric Assistance Program, including development, implementation, and ongoing administrative and maintenance costs against the actual amounts charged to customers through the portion of the System Benefits Charge attributable to the Electric Assistance Program, set at a level of 0.150¢ per kilowatt-hour in accordance with RSA 374-F:4, VIII (c), and shall be in addition to the portion of the System Benefits Charge relating to the Company's energy efficiency core programs stated below.

The Company shall implement its energy efficiency core programs as approved by the Commission from time to time. The Company's cost of implementing the energy efficiency core programs shall be recovered through the portion of the System Benefits Charge attributable to such programs, set at a level of 0.528¢ per kilowatt-hour in accordance with RSA 374-F:3, VI-a(d)(2) which shall be in addition to the portion of the System Benefits Charge relating to the Company's low income customer protection programs stated above. Any difference between the actual energy efficiency funds expended and the funds collected through the System Benefits Charge at 0.528¢ per kilowatt-hour during a calendar year shall, with interest calculated at the average prime rate for each month, be added to or subtracted from the amount to be expended in the following calendar year. If actual amounts are not available for any period, they shall be estimated for purposed of the above calculations and adjusted the following year based on actual data.

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System Benefits Charge

Electric Assistance Program (EAP)	0.150¢
Energy Efficiency Programs	0.528¢
Lost Revenue Mechanism	0.114¢
Total System Benefit Charge	0.792¢

42. Late Payment Charge

The rates and charges billed under this Tariff are net, billed monthly and payable upon presentation of the bill. However, Customers who receive Delivery Service under Residential Rate D, Residential Time-of-Day Rate D-10, OR General Service Rate G-3, may elect to pay for all service rendered under these rates, as well as Energy Service Rate ES, on a Levelized Payment Plan available upon application to the Company.

For Customers rendered Delivery Service under General Service Rate G-3, General Long Hour Service Rate G-2 or General Service Time-of-Use Rate G-1, all amounts previously billed but remaining unpaid after the due date printed on the bill shall be subject to a late payment charge of one and one-half percent (1 ½ %) thereof, such amounts to include any prior unpaid late payment charges.

The late payment charge is not applicable to Customers taking service under Rate D and Rate D-10, or past due balances of General Service Rate G-3 or Outdoor Lighting Rate M Customers who are abiding by the terms of an extended payment arrangement agreed to by the Company.

43. Provisions for Billing Charges Associated with Meter Diversions and Damage to Company Equipment in Connection Therewith

In case of loss or damage to the Company's property on a Customer's premises the Customer shall pay to the Company the value of the property or the cost of making good the loss or damage.

In those cases where, as a result of or in connection with diversion of electricity supplied by the Company to the Customer's premises, whether such diversion is carried out by bypassing the meter or other measuring device or by other means, the Company incurs expense for labor and/or materials, the Customer responsible therefore will be charged the costs incurred by the Company for such labor and materials. The costs so chargeable may include, but are not limited to, the cost of investigating the diversion and the miscellaneous charges for service associated therewith, the cost of supplying and installing an exchange meter, the cost of furnishing and installing tamper-resistant devices, the cost of testing the meter associated with the diversion and the cost of replacement of a meter which has been damaged.

System Benefits Charge

Electric Assistance Program (EAP)	0.150¢
Energy Efficiency Programs	0.528¢
Lost Revenue Mechanism	0.114~~000~~¢
Total System Benefit Charge	0.792~~678~~¢

42. Late Payment Charge

The rates and charges billed under this Tariff are net, billed monthly and payable upon presentation of the bill. However, Customers who receive Delivery Service under Residential Rate D, Residential Time-of-Day Rate D-10, OR General Service Rate G-3, may elect to pay for all service rendered under these rates, as well as Energy Service Rate ES, on a Levelized Payment Plan available upon application to the Company.

For Customers rendered Delivery Service under General Service Rate G-3, General Long Hour Service Rate G-2 or General Service Time-of-Use Rate G-1, all amounts previously billed but remaining unpaid after the due date printed on the bill shall be subject to a late payment charge of one and one-half percent (1 ½ %) thereof, such amounts to include any prior unpaid late payment charges.

The late payment charge is not applicable to Customers taking service under Rate D and Rate D-10, or past due balances of General Service Rate G-3 or Outdoor Lighting Rate M Customers who are abiding by the terms of an extended payment arrangement agreed to by the Company.

43. Provisions for Billing Charges Associated with Meter Diversions and Damage to Company Equipment in Connection Therewith

In case of loss or damage to the Company's property on a Customer's premises the Customer shall pay to the Company the value of the property or the cost of making good the loss or damage.

In those cases where, as a result of or in connection with diversion of electricity supplied by the Company to the Customer's premises, whether such diversion is carried out by bypassing the meter or other measuring device or by other means, the Company incurs expense for labor and/or materials, the Customer responsible therefore will be charged the costs incurred by the Company for such labor and materials. The costs so chargeable may include, but are not limited to, the cost of investigating the diversion and the miscellaneous charges for service associated therewith, the cost of supplying and installing an exchange meter, the cost of furnishing and installing tamper-resistant devices, the cost of testing the meter associated with the diversion and the cost of replacement of a meter which has been damaged.

RATES EFFECTIVE MAY 1, 2022
FOR USAGE ON AND AFTER MAY 1, 2022

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
D	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.06038	0.00064	**0.06102**	0.03703	(0.00080)	-	0.00792	-	**0.10517**	0.11119	**$ 0.21636**
Off Peak Water Heating Use 16 Hour Control[1]	All kWh	$ 0.05213	0.00064	**0.05277**	0.03703	(0.00080)	-	0.00792	-	**0.09692**	0.11119	**$ 0.20811**
Off Peak Water Heating Use 6 Hour Control[1]	All kWh	$ 0.05310	0.00064	**0.05374**	0.03703	(0.00080)	-	0.00792	-	**0.09789**	0.11119	**$ 0.20908**
Farm[1]	All kWh	$ 0.05699	0.00064	**0.05763**	0.03703	(0.00080)	-	0.00792	-	**0.10178**	0.11119	**$ 0.21297**
D-10	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	On Peak kWh	$ 0.12809	0.00064	**0.12873**	0.02848	(0.00080)	-	0.00792	-	**0.16433**	0.11119	**$ 0.27552**
	Off Peak kWh	$ 0.00172	0.00064	**0.00236**	0.02848	(0.00080)	-	0.00792	-	**0.03796**	0.11119	**$ 0.14915**
G-1	Customer Charge	$ 444.70		**444.70**						**444.70**		**$ 444.70**
	Demand Charge	$ 9.43		**9.43**						**9.43**		**$ 9.43**
	On Peak kWh	$ 0.00603	0.00064	**0.00667**	0.02957	(0.00080)	-	0.00792	-	**0.04336**		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24594**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17758**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.13321**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.11420**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11779**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12660**
	Off Peak kWh	$ 0.00178	0.00064	**0.00242**	0.02957	(0.00080)	-	0.00792	-	**0.03911**		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24169**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17333**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.12896**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.10995**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11354**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12235**
G-2	Customer Charge	$ 74.11		**74.11**						**74.11**		**$ 74.11**
	Demand Charge	$ 9.48		**9.48**						**9.48**		**$ 9.48**
	All kWh	$ 0.00239	0.00064	**0.00303**	0.03418	(0.00080)	-	0.00792	-	**0.04433**		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24691**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17855**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.13418**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.11517**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11876**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12757**
G-3	Customer Charge	$ 17.03		**17.03**						**17.03**		**$ 17.03**
	All kWh	$ 0.05398	0.00064	**0.05462**	0.03104	(0.00080)	-	0.00792	-	**0.09278**	0.11119	**$ 0.20397**
T	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.04871	0.00064	**0.04935**	0.02795	(0.00080)	-	0.00792	-	**0.08442**	0.11119	**$ 0.19561**
V	Minimum Charge	$ 17.03		**17.03**						**17.03**		**$ 17.03**
	All kWh	$ 0.05552	0.00064	**0.05616**	0.02456	(0.00080)	-	0.00792	-	**0.08784**	0.11119	**$ 0.19903**

[1] Rate is a subset of Domestic Rate D

Dated: XX XX, 2022
Effective: May 1, 2022

Issued by: /s/Neil Proudman
Neil Proudman
Title: President

Authorized by NHPUC Order No.___ in Docket No. DE 20-092, dated ___

RATES EFFECTIVE MAY 1, 2022
FOR USAGE ON AND AFTER MAY 1, 2022

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
	Customer Charge	$14.74		**$14.74**								**$14.74**
	Monday through Friday											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	$0.00792	-	**$0.05430**	$0.10659	**$0.16089**
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	$0.00792	-	**$0.08023**	$0.12161	**$0.20184**
D-11	Critical Peak	$0.09478	$0.00064	**$0.09542**	$0.23553	($0.00080)	-	$0.00792	-	**$0.33807**	$0.12636	**$0.46443**
	Saturday through Sunday and Holidays											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	$0.00792	-	**$0.05430**	$0.10659	**$0.16089**
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	$0.00792	-	**$0.08023**	$0.12161	**$0.20184**
	Customer Charge	$11.35		**$11.35**								**$11.35**
	Monday through Friday											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	$0.00792	-	**$0.05430**	$0.10659	**$0.16089**
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	$0.00792	-	**$0.08023**	$0.12161	**$0.20184**
Rate EV	Critical Peak	$0.09478	$0.00064	**$0.09542**	$0.23553	($0.00080)	-	$0.00792	-	**$0.33807**	$0.12636	**$0.46443**
	Saturday through Sunday and Holidays											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	$0.00792	-	**$0.05430**	$0.10659	**$0.16089**
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	$0.00792	-	**$0.08023**	$0.12161	**$0.20184**
	Luminaire Charge											
	HPS 4,000	$8.72		**$8.72**								**$8.72**
	HPS 9,600	$10.08		**$10.08**								**$10.08**
	HPS 27,500	$16.73		**$16.73**								**$16.73**
	HPS 50,000	$20.81		**$20.81**								**$20.81**
	HPS 9,600 (Post Top)	$11.83		**$11.83**								**$11.83**
	HPS 27,500 Flood	$16.91		**$16.91**								**$16.91**
M	HPS 50,000 Flood	$22.58		**$22.58**								**$22.58**
	Incandescent 1,000	$11.19		**$11.19**								**$11.19**
	Mercury Vapor 4,000	$7.74		**$7.74**								**$7.74**
	Mercury Vapor 8,000	$8.69		**$8.69**								**$8.69**
	Mercury Vapor 22,000	$15.54		**$15.54**								**$15.54**
	Mercury Vapor 63,000	$26.26		**$26.26**								**$26.26**
	Mercury Vapor 22,000 Flood	$17.78		**$17.78**								**$17.78**
	Mercury Vapor 63,000 Flood	$34.44		**$34.44**								**$34.44**
	Luminaire Charge											
	30 Watt Pole Top	$5.66		**$5.66**								**$5.66**
	50 Watt Pole Top	$5.90		**$5.90**								**$5.90**
	130 Watt Pole Top	$9.10		**$9.10**								**$9.10**
LED-1	190 Watt Pole Top	$17.44		**$17.44**								**$17.44**
	30 Watt URD	$13.18		**$13.18**								**$13.18**
	90 Watt Flood	$8.96		**$8.96**								**$8.96**
	130 Watt Flood	$10.31		**$10.31**								**$10.31**
	30 Watt Caretaker	$5.07		**$5.07**								**$5.07**
	Pole -Wood	$9.87		**$9.87**								**$9.87**
	Fiberglass - Direct Embedded	$10.28		**$10.28**								**$10.28**
Poles	Fiberglass w/Foundation <25 ft	$17.35		**$17.35**								**$17.35**
	Fiberglass w/Foundation >=25 ft	$29.01		**$29.01**								**$29.01**
	Metal Poles - Direct Embedded	$20.68		**$20.68**								**$20.68**
	Metal Poles with Foundation	$24.95		**$24.95**								**$24.95**
M & LED-1	All kWh	$0.04152	$0.00064	**$0.04216**	$0.02179	($0.00080)	$0.00000	$0.00792	$0.00000	**$0.07107**	$0.11119	**$0.18226**
LED-2	All kWh	$0.04152	$0.00064	**$0.04216**	$0.02179	($0.00080)	$0.00000	$0.00792	$0.00000	**$0.07107**	$0.11119	**$0.18226**

Dated: XX XX, 2022
Effective: May 1, 2022

Issued by: /s/Neil Proudman
Neil Proudman
Title: President

Authorized by NHPUC Order No. ___in Docket No. DE 20-092, dated ___

NHPUC No. 21 - ELECTRICITY
LIBERTY UTILITIES

~~Tenth~~ Revised Page 126
Superseding ~~Ninth~~ Revised Page 126
Summary of Rates

RATES EFFECTIVE ~~MARCH 1, 2022~~
FOR USAGE ON AND AFTER ~~MARCH 1, 2022~~

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
D	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.06038	0.00064	**0.06102**	0.03703	(0.00080)	-	~~0.00678~~	-	~~**0.10403**~~	0.11119	~~**$ 0.21522**~~
Off Peak Water Heating Use 16 Hour Control[1]	All kWh	$ 0.05213	0.00064	**0.05277**	0.03703	(0.00080)	-	~~0.00678~~	-	~~**0.09578**~~	0.11119	~~**$ 0.20697**~~
Off Peak Water Heating Use 6 Hour Control[1]	All kWh	$ 0.05310	0.00064	**0.05374**	0.03703	(0.00080)	-	~~0.00678~~	-	~~**0.09675**~~	0.11119	~~**$ 0.20794**~~
Farm[1]	All kWh	$ 0.05699	0.00064	**0.05763**	0.03703	(0.00080)	-	~~0.00678~~	-	~~**0.10064**~~	0.11119	~~**$ 0.21183**~~
D-10	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	On Peak kWh	$ 0.12809	0.00064	**0.12873**	0.02848	(0.00080)	-	~~0.00678~~	-	~~**0.16319**~~	0.11119	~~**$ 0.27438**~~
	Off Peak kWh	$ 0.00172	0.00064	**0.00236**	0.02848	(0.00080)	-	~~0.00678~~	-	~~**0.03682**~~	0.11119	~~**$ 0.14801**~~
G-1	Customer Charge	$ 444.70		**444.70**						**444.70**		**$ 444.70**
	Demand Charge	$ 9.43		**9.43**						**9.43**		**$ 9.43**
	On Peak kWh	$ 0.00603	0.00064	**0.00667**	0.02957	(0.00080)	-	~~0.00678~~	-	~~**0.04222**~~		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24480**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17644**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.13207**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.11306**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11665**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12546**
	Off Peak kWh	$ 0.00178	0.00064	**0.00242**	0.02957	(0.00080)	-	~~0.00678~~	-	~~**0.03797**~~		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24055**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17219**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.12782**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.10881**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11240**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12121**
G-2	Customer Charge	$ 74.11		**74.11**						**74.11**		**$ 74.11**
	Demand Charge	$ 9.48		**9.48**						**9.48**		**$ 9.48**
	All kWh	$ 0.00239	0.00064	**0.00303**	0.03418	(0.00080)	-	~~0.00678~~	-	~~**0.04319**~~		
										Effective 2/1/22, usage on or after	0.20258	**$ 0.24577**
										Effective 3/1/22, usage on or after	0.13422	**$ 0.17741**
										Effective 4/1/22, usage on or after	0.08985	**$ 0.13304**
										Effective 5/1/22, usage on or after	0.07084	**$ 0.11403**
										Effective 6/1/22, usage on or after	0.07443	**$ 0.11762**
										Effective 7/1/22, usage on or after	0.08324	**$ 0.12643**
G-3	Customer Charge	$ 17.03		**17.03**						**17.03**		**$ 17.03**
	All kWh	$ 0.05398	0.00064	**0.05462**	0.03104	(0.00080)	-	~~0.00678~~	-	~~**0.09164**~~	0.11119	~~**$ 0.20283**~~
T	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.04871	0.00064	**0.04935**	0.02795	(0.00080)	-	~~0.00678~~	-	~~**0.08328**~~	0.11119	~~**$ 0.19447**~~
V	Minimum Charge	$ 17.03		**17.03**						**17.03**		**$ 17.03**
	All kWh	$ 0.05552	0.00064	**0.05616**	0.02456	(0.00080)	-	~~0.00678~~	-	~~**0.08670**~~	0.11119	~~**$ 0.19789**~~

[1] Rate is a subset of Domestic Rate D

Dated: ~~February 25, 2022~~
Effective: ~~March 1, 2022~~

Issued by: /s/Neil Proudman
Neil Proudman
Title: President

~~Authorized by NHPUC Order No. 26,579 in Docket No. DE 20-092, dated February 10, 2022~~

RATES EFFECTIVE ~~MARCH 1, 2022~~
FOR USAGE ON AND AFTER ~~MARCH 1, 2022~~

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
	Customer Charge	$14.74		**$14.74**								**$14.74**
	Monday through Friday											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	~~$0.00678~~	-	~~**$0.05316**~~	$0.10659	~~**$0.15975**~~
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	~~$0.00678~~	-	~~**$0.07909**~~	$0.12161	~~**$0.20070**~~
D-11	Critical Peak	$0.09478	$0.00064	**$0.09542**	$0.23553	($0.00080)	-	~~$0.00678~~	-	~~**$0.33693**~~	$0.12636	~~**$0.46329**~~
	Saturday through Sunday and Holidays											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	~~$0.00678~~	-	~~**$0.05316**~~	$0.10659	~~**$0.15975**~~
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	~~$0.00678~~	-	~~**$0.07909**~~	$0.12161	~~**$0.20070**~~
	Customer Charge	$11.35		**$11.35**								**$11.35**
	Monday through Friday											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	~~$0.00678~~	-	~~**$0.05316**~~	$0.10659	~~**$0.15975**~~
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	~~$0.00678~~	-	~~**$0.07909**~~	$0.12161	~~**$0.20070**~~
Rate EV	Critical Peak	$0.09478	$0.00064	**$0.09542**	$0.23553	($0.00080)	-	~~$0.00678~~	-	~~**$0.33693**~~	$0.12636	~~**$0.46329**~~
	Saturday through Sunday and Holidays											
	Off Peak	$0.04441	$0.00064	**$0.04505**	$0.00213	($0.00080)	-	~~$0.00678~~	-	~~**$0.05316**~~	$0.10659	~~**$0.15975**~~
	Mid Peak	$0.06657	$0.00064	**$0.06721**	$0.00590	($0.00080)	-	~~$0.00678~~	-	~~**$0.07909**~~	$0.12161	~~**$0.20070**~~
	Luminaire Charge											
	HPS 4,000	$8.72		**$8.72**								**$8.72**
	HPS 9,600	$10.08		**$10.08**								**$10.08**
	HPS 27,500	$16.73		**$16.73**								**$16.73**
	HPS 50,000	$20.81		**$20.81**								**$20.81**
	HPS 9,600 (Post Top)	$11.83		**$11.83**								**$11.83**
	HPS 27,500 Flood	$16.91		**$16.91**								**$16.91**
M	HPS 50,000 Flood	$22.58		**$22.58**								**$22.58**
	Incandescent 1,000	$11.19		**$11.19**								**$11.19**
	Mercury Vapor 4,000	$7.74		**$7.74**								**$7.74**
	Mercury Vapor 8,000	$8.69		**$8.69**								**$8.69**
	Mercury Vapor 22,000	$15.54		**$15.54**								**$15.54**
	Mercury Vapor 63,000	$26.26		**$26.26**								**$26.26**
	Mercury Vapor 22,000 Flood	$17.78		**$17.78**								**$17.78**
	Mercury Vapor 63,000 Flood	$34.44		**$34.44**								**$34.44**
	Luminaire Charge											
	30 Watt Pole Top	$5.66		**$5.66**								**$5.66**
	50 Watt Pole Top	$5.90		**$5.90**								**$5.90**
	130 Watt Pole Top	$9.10		**$9.10**								**$9.10**
LED-1	190 Watt Pole Top	$17.44		**$17.44**								**$17.44**
	30 Watt URD	$13.18		**$13.18**								**$13.18**
	90 Watt Flood	$8.96		**$8.96**								**$8.96**
	130 Watt Flood	$10.31		**$10.31**								**$10.31**
	30 Watt Caretaker	$5.07		**$5.07**								**$5.07**
	Pole -Wood	$9.87		**$9.87**								**$9.87**
	Fiberglass - Direct Embedded	$10.28		**$10.28**								**$10.28**
Poles	Fiberglass w/Foundation <25 ft	$17.35		**$17.35**								**$17.35**
	Fiberglass w/Foundation >=25 ft	$29.01		**$29.01**								**$29.01**
	Metal Poles - Direct Embedded	$20.68		**$20.68**								**$20.68**
	Metal Poles with Foundation	$24.95		**$24.95**								**$24.95**
M & LED-1	All kWh	$0.04152	$0.00064	**$0.04216**	$0.02179	($0.00080)	$0.00000	~~$0.00678~~	$0.00000	~~**$0.06993**~~	$0.11119	~~**$0.18112**~~
LED-2	All kWh	$0.04152	$0.00064	**$0.04216**	$0.02179	($0.00080)	$0.00000	~~$0.00678~~	$0.00000	~~**$0.06993**~~	$0.11119	~~**$0.18112**~~

Dated: ~~February 25, 2022~~
Effective: ~~March 1, 2022~~

Issued by: /s/Neil Proudman
Neil Proudman
Title: President

~~Authorized by NHPUC Order No. 26,579 in Docket No. DE 20-092, dated February 10, 2022~~

THE STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY OF

CAROL M. WOODS

PROPOSED 2022-2023 SYSTEM BENEFITS CHARGE RATE CHANGE

Docket No. DE 20-092

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, by whom you are employed and in what capacity.

A. My name is Carol M. Woods. I am employed by New Hampshire Electric Cooperative as Energy Solutions Executive. My responsibilities include management of planning and regulatory support for the company's energy efficiency programs.

Q. Have you previously testified before the Commission?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support the calculation of the Energy Efficiency ("EE") component of the System Benefits Charge ("SBC") proposed for effect March 1, 2022, and January 1, 2023. My testimony explains what is contained in Attachment G3, which provides the calculation of the EE rate components of the SBC for New Hampshire Electric Cooperative.

II. EE COMPONENT OF THE SBC

Q. What is the proposed EE Component of the SBC?

A. The proposed statewide EE rate for effect on March 1, 2022 is $0.00528 per kWh and is estimated to be $0.00543 per kWh for effect on January 1, 2023. In accordance with HB 549, which was passed into law on February 24, 2022, amending RSA 374-F:3, VI ("HB 549"), the EE portion of the SBC resets to the 2020/2021 level for 2022, and for 2023, the EE portion of the SBC is "calculated using the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States Department of Labor plus 0.25 percent [adder to account for inflation] all as calculated by the Department of Energy."[1] The estimated rate for effect on January 1, 2023 will be updated on December 1, 2022 to incorporate the inflation adder, in accordance with HB 549.

Q. How was the EE rate calculated?

A. The EE portion of the SBC rate was set by HB 549 - explicitly for 2022, and then using the 2022 rate and adjusting it as discussed above for 2023. Pages 2 and 3 of Attachment G3 provides the forecasted revenues and expenses and a preliminary reconciliation of the EE component of the SBC rate for 2022 and 2023.

III. TOTAL SBC AND BILL IMPACTS

[1] House Bill 549, *An Act Relative to the System Benefits Charge and the Energy Efficiency and Sustainable Energy Board,* signed into law by the Governor on February 24, 2022.

Q. What is the total proposed SBC?

A. As shown on Page 1 of Attachments G3, which provides a summary of the calculation of the SBC rate, the total proposed SBC is \$0.00678 per kWh. The SBC consists of the EE rate components discussed above and the Electric Assistance Program ("EAP") rate component of \$0.00150 per kWh, which remains unchanged as of the date of this filing.

Q. Have you provided bill impacts associated with the proposed SBC?

A. Yes. The bill impact for a typical residential and C&I member is provided on Page 4 of Attachment G3.

Q. Do the utilities require Commission approval of the SBC billed to members by a specific date?

A. No, as discussed above, the statewide EE rate is set in HB 549.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

UNITIL ENERGY SYSTEMS, INC.

AND

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY OF

CHRISTOPHER J. GOULDING

ATTACHMENT K

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 20-092

MARCH 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher J. Goulding, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. Mr. Goulding, what is your position and what are your responsibilities?

A. I am the Director of Rates and Revenue Requirements for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's utility subsidiaries including Unitil Energy Systems, Inc., ("UES") and Northern Utilities ("Northern"). My responsibilities include all rate and regulatory filings related to the financial requirements of UES and Northern as well as Unitil's other subsidiaries.

Q. Please describe your business and educational background.

A. In 2000 I was hired by NSTAR Electric & Gas Company ("NSTAR," now Eversource Energy) and held various positions with increasing responsibilities in Accounting, Corporate Finance and Regulatory. I was hired by Unitil Service Corp. in early 2019 to perform my current job responsibilities. I earned a Bachelor of Science degree in Business Administration from Northeastern

University in 2000 and a Master's in Business Administration from Boston College in 2009.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. Yes.

Q. What is the purpose of your testimony?

A. For UES, the purpose of my testimony is: (1) to present the Energy Efficiency ("EE") component of the System Benefits Charge ("SBC") that was effective February 14, 2022, and the preliminary rate for effect January 1, 2023; (2) to present and support the calculation of the UES lost base revenue ("LBR") component of the Systems Benefit Charge ("SBC") proposed for effect May 1, 2022 to December 31, 2022; and (3) to present the total SBC rate including the Electric Assistance Program ("EAP) portion of the SBC. My testimony provides a detailed explanation of Attachment H3 which provides the changes made for the LBR rate component effective May 1, 2022 to comply with the directives or Order No. 26,560 issued in Docket No. DE 20-092 on January 7, 2022.

For Northern, the purpose of the my testimony is: (1) to present the Energy Efficiency Charge ("EEC") that is effective March 1, 2022, and the preliminary rate for effect January 1, 2023 in order to address the passage of HB 549 into law on February 24, 2022; and (2) to detail how the current Lost Revenue Rate ("LRR") for NU complies with Order No. 26,560 issued in Docket No. DE 20-092 and does not need to be updated at this time.

II. EE COMPONENT OF THE SBC

Q. What is the proposed EE component of the SBC?

A. The statewide EE rate for effect March 1, 2022 is $0.00528 per kWh and is estimated to be $0.00543 per kWh for effect on January 1, 2023. This resets the EE portion of the SBC to the 2020/2021 level for 2022, and for 2023 was "calculated using the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States Department of Labor plus 0.25 percent [to account for inflation] all as calculated by the department of energy" both in accordance with HB 549. The estimated rate for effect January 1, 2023 will be updated by December 1, 2022 to account for any over or under collections and to incorporate the inflation calculation in accordance with HB 549.

Q. How was the EE rate calculated?

A. The EE portion of the 2022 SBC rate was set by the legislature in HB 549 and then for 2023, the 2022 rate was adjusted as discussed above for 2023.

Q. What is the currently effective EE rate for UES?

A. The EE rate for UES that has been in effect since February 14, 2022 is $0.00528 per kWh consistent with Order No. 26,579 issued on February 10, 2022 in Docket No. DE 20-092, therefore the EE portion of the SBC rate is not changing on March 1, 2022.

III. LBR COMPONENT OF THE SBC (UES)

Q. What is the proposed LBR component of the SBC?

A. The table below shows the current LBR component of the SBC rate that has been in effect since January 1, 2020 and the proposed rate for effect May 1, 2022.

Unitil	Current SBC Rate LBR Portion ($/kWh)	Proposed May 1, 2022 SBC Rate LBR Portion ($/kWh)	Change
SBC LBR Charge ($/kWh)	$0.00074	$0.00003	($0.00071)

Q. Please explain how the LBR rate was calculated.

A. As shown on page 1 of Attachment H3, the sum of the forecast lost base revenue, plus the prior year balance, plus current year interest, is divided by the forecasted sales to arrive at the proposed rates. Pages 2 and 3 provide the monthly savings for 2021 and 2022 and the lost revenue calculations. Pages 4 provides a preliminary reconciliation of the actual monthly revenues collected from the LBR rate during 2021. Page 5 provides a reconciliation of the actual and forecasted monthly revenues collected from the LBR rate during 2022. Pages 6 and 7 calculate the 2020 savings not reflected in the 2020 test year billing determinants and not reflected in Temporary rates that became effective on June 1, 2021 in Docket No. DE 21-030. Pages 8 and 9 provide a computation of the average sector distribution rates for use in the lost revenue calculation. Additional details supporting the actual average rate calculation has been provided on page 10, 11 and 13. Page 12 provides the bill impacts associated with the proposed change to the SBC rate on May 1, 2022 due to the LBR component of the SBC being decreased.

Q. Please explain why the LBR component has decreased significantly.

A. The primary drivers of the decrease in the LBR component of the SBC rate are (1) the removal of 2017, 2018, 2019 and 2020 test year impacted savings from the LBR calculation effective with the implementation of temporary rates on June 1, 2021 in Docket No. DE 21-030; and (2) and ceasing to accrue LBR after March 31, 2022 to account for the Company's proposed transition to decoupling on April 1, 2022 in Docket No. DE 21-030.

Q. Is your calculation of the 2021 and 2022 lost revenues and transition to decoupling consistent with the Section 4.4 of UES's pending rate case settlement in Docket No. DE 21-030?

A. Yes.

Q. Will UES have a LBR component of the SBC on January 1, 2023?

A. Assuming the transition to decoupling occurs on April 1, 2022 as filed in the UES rate case, there will be a final reconciliation that is necessary that could result in the need for a LBR component of the SBC rate for January 1, 2023 unless the final reconciliation is addressed as part of another reconciling mechanism.

IV. TOTAL SBC AND BILL IMPACTS (UES)

Q. What is the total proposed SBC rate?

A. For UES, the total SBC rates effective February 14, 2022, proposed for May 1, 2022 and the preliminary rate for January 1, 2023 are shown in the table below:

Effective	SBC Rate EE Portion ($/kWh)	SBC Rate EAP Portion ($/kWh)	SBC Rate LBR Portion ($/kWh)	Total SBC Rate ($/kWh)
Feb 14, 2022 to April 30, 2022	$0.00528	$0.00150	$0.00074	$0.00752
May 1, 2022 to December 31, 2022	$0.00528	$0.00150	$0.00003	$0.00681
January 1, 2023 to December 31, 2023	$0.00543	$0.00150	$0.00000	$0.00693

Q. Have you provided bill impacts associated with the proposed May 1, 2022 SBC?

A. Yes, page 12 of Attachment H3 contains the bill impacts for an average residential customer and for a small general service customer assuming 40 kW and 10,000 kWh of usage per month.

Q. Does the Company require Commission approval of the SBC billed to customers by a specific date?

A. Yes, the Company respectfully requests that the Commission approve the LBR portion of the SBC rates by Friday April 29, 2022 so that a complete updated SBC rate can be implemented effective May 1, 2022.

V. EEC FOR NORTHERN

Q. What is the proposed EEC?

A. The residential EEC for effect March 1, 2022 is $0.0499 per therm and estimated to be $0.0513 per therm for January 1, 2023. The C&I EEC for effect March 1, 2022 is $0.0247 per therm and estimated to be $0.0254 per therm for effect on January 1, 2023. For Northern, the March 1 rates are established consistent with HB 549 and NHPUC Order No. 26,303 in Docket No. DG 19-154 dated October 29, 2019.

Q. How were the preliminary January 1, 2023 EECs calculated?

A. The January 1, 2023 EECs are calculated by inflating the March 1, 2022 EECs by the most recently available 3-year average of the consumer price index ("CPI-W") as published by the Bureau of Labor Statistics of the United States Department of Labor plus 0.25 percent [to account for inflation] in accordance with HB 549. The estimated rates for effect January 1, 2023 will be updated by December 1, 2022 to account for any over or under collections and to incorporate the updated inflation calculation in accordance with HB 549.

VI. LRR FOR NORTHERN

Q. When were the LRRs for Northern last updated and what are the current LRRs for Northern?

A. The current LRRs for Northern were last updated in DG 21-131 with the rates effective November 1, 2021. The current residential LRR is $0.0066 per therm and the current C&I LRR is $0.0006 per therm.

Q. Did the LRRs that were effective November 1, 2021 account for Northern's rate case filing in DG 21-104?

A. Yes, the LRRs approved in DG 21-131 account for the company's proposal to transition to decoupling on August 1, 2022 and temporary rates effective October 1, 2021.

Q. How was the timing of the Northern rate case reflected in the LRRs effective November 1, 2021?

A. The LRRs effective November 1, 2021 remove any savings prior to and reflected in the test year from the calculation effective with temporary rates on October 1, 2022 and cease accruing lost revenue effective with the implementation of decoupling which is proposed for August 1, 2022.

Q. Is it necessary to do a future reconciliation of Northern's LRR calculation?

A. Yes. The lost revenue calculation has certain assumptions related to the 2021 savings and the first seven months of 2022 savings. Once the savings are finalized as part the Energy Efficiency Annual Report (mid 2022 for 2021 activity and mid 2023 for 2022 activity), a final reconciliation of the LRRs will be necessary.

VII. BILL IMPACTS (NORTHERN)

Q. For Northern, what are the current EECs, the EECs effective March 1, 2022 and the preliminary rates for January 1, 2023?

A. The rates have been provided in the table below:

Effective	Residential EEC Rate ($/therm)	C&I EEC Rate ($/therm)
Current Rate through February 28, 2022	$0.0476	$0.0326
March 1, 2022 to December 31, 2022	$0.0499	$0.0247
January 1, 2023 to December 31, 2023	$0.0513	$0.0254

Q. What is the bill impact for an average residential heating customer?

A. An average residential customer using 732 therms annually would see an increase in their annual bill of $1.68 associated with the increase in the EEC from $0.0476 per therm to $0.499 per therm.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Avoided Energy Supply Components in New England: 2021 Report

Prepared for AESC 2021 Study Group

Released March 15, 2021
Amended May 14, 2021

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AMENDMENTS TO THE AESC 2021 STUDY

This is the second public release of the AESC 2021 Study. This document updates and amends the version originally released on March 15, 2021. The following text summarizes these changes.

- Text in Chapter 12: *Sensitivity Analysis* is now populated. Corresponding text was added to the executive summary (in the subsection titled "Sensitivities").
- We updated text in Chapter 2: *Avoided Natural Gas Costs* related to the calculation of the medium-term Henry Hub natural gas price forecast. Text in the March 15 edition referred to a methodology used in earlier drafts. This text has now been updated to reflect our final methodology. We also modified text in the natural gas section of the Executive Summary to reflect this update. We note that these are changes to the text only; all of the modeled avoided costs are unchanged.
- We clarified which avoided transmission and distribution (T&D) costs are included in summary tables like ES-Table 1. These tables only included avoided T&D costs related to pooled transmission facilities (PTF) and do not include non-PTF avoided T&D costs or avoided costs related to local T&D systems.
- We made a cosmetic correction to the Y-axis in Figure 17.
- In Section 8.1. *Non-embedded GHG costs*, the paragraph that begins with "In AESC 2018, the cost of avoided CO_2 was reported to be $68 per short ton…" was edited for clarity.
- We corrected a typographical error in Table 56 so that the "CES-E" program correctly refers to Massachusetts, rather than Maine.
- Numbering of figures, tables, footnotes, and pages has changed due to the inclusion of new text in Chapter 12: *Sensitivity Analysis* and other edits throughout the document.
- We have corrected a formula error in each of the AESC 2021 User Interface workbooks, on the sheet named "NonEmbedded_Calcs." In practical terms, this increases the non-embedded GHG cost for Vermont (assuming a New England marginal abatement cost-basis) by 1 percent. There are no other changes to other regions. No updates were required to tables or text in this document.

There are no further amendments, notes, or errata at this time.

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LIST OF ACRONYMS

AESC	Avoided energy supply component/ cost
AEO	Annual Energy Outlook
Bcf	Billion cubic feet
CAGR	Compound annual growth rate
CEC	Clean Energy Certificate
CES	Clean Energy Standard
CCS	Carbon capture and sequestration
DOER	Massachusetts Department of Energy Resources
DRIPE	Demand reduction induced price effects
EIA	U.S. Energy Information Administration
FCA	Forward capacity auction
FCM	Forward capacity market
GWSA	Global Warming Solutions Act
HDD	Heating degree day
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent system operator
LDC	Local distribution company
LMP	Locational marginal price
LNG	Liquefied natural gas
LSE	Load-serving entity
MMcf	Million cubic feet
Net ICR	Net installed capacity requirement
PTF	Pool transmission facilities
REC	Renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable natural gas
RPS	Renewable portfolio standard
VoLL	Value of lost load

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1. EXECUTIVE SUMMARY

This document is the 2021 Avoided Energy Supply Component (AESC) Study (AESC 2021). AESC 2021 contains cost streams of marginal energy supply components that can be avoided in future years due to reductions in the use of electricity, natural gas, and other fuels as a result of program-based energy efficiency or other demand-side measures across all six New England states.

The AESC Study provides estimates of avoided costs associated with energy efficiency measures for program administrators throughout New England states for purposes of both internal decision-making and regulatory filings. To determine the values of energy efficiency and other demand-side measures, avoided costs are calculated and provided for each New England state in a hypothetical future in which the New England program administrators do not install any new demand-side measures in 2021 or later years. New to this year's study, AESC 2021 features four different counterfactuals:

- **Counterfactual #1:** A future in which program administrators install no new energy efficiency, building electrification, or active demand management (demand response and energy storage) resources in 2021 or later years.
- **Counterfactual #2:** A future in which program administrators install no new building electrification resources in 2021 or later years. This future does model some amount of energy efficiency and active demand management resources installed by the program administrators.
- **Counterfactual #3:** A future in which program administrators install no new energy efficiency resources in 2021 or later years. This future does model some amount of building electrification and active demand management resources installed by the program administrators.
- **Counterfactual #4:** A future in which program administrators install no new energy efficiency resources in 2021 or later years. This future does model some amount of building electrification installed by the program administrators but does not include any active demand management resources installed by the program administrators.

Because each AESC counterfactual represents a hypothetical future that lacks some amount of anticipated demand-side measures, AESC 2021 should not be used to infer information about actual future market conditions, energy prices, or resource builds in New England. Furthermore, actual prices in the future will be different than the long-term prices calculated in this study since actual future prices will be subject to short-term variations in energy markets that are unknowable at this point in time. Note also that these caveats may also apply to sensitives modeled in the AESC 2021 Study (see Chapter 12 for more information).

As in previous AESC studies, this study examines avoided costs of energy, capacity, natural gas, fuel oil, other fuels, other environmental costs, and demand reduction induced price effects (DRIPE). Also, AESC 2021 relies upon a combination of models to estimate each one of these avoided costs for each future year. As in AESC 2018, this study provides avoided energy costs on an hourly basis. This allows users of the report to estimate avoided costs specific to a broad array of active demand response programs, including active load management and peak load shifting programs. Other avoided costs (e.g., natural gas, fuel oil) are provided at the time resolutions that are most appropriate for their markets (e.g., daily, seasonal, or annual).

On a 15-year levelized basis, in real 2021 dollars, the AESC 2021 Study estimates that direct avoided retail energy costs are approximately 4 cents per kWh for Counterfactual #1, and direct avoided gas costs are $6 per MMBtu, although these vary on the specific location and end-use. Compared to 2018 AESC, we find:

- 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 in the 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, CO_2, and nitrogen oxides, NO_X) 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). AESC 2021 also presents additional methodologies for quantifying localized and non-PTF transmission and distribution avoided costs.
- 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.

AESC 2021 provides detailed projections of avoided costs by year for an initial 15-year period based on modeling (2021 through 2035), and a second period based on extrapolation of values from this first period (2036 through 2055).[1] All values in this document are described in terms of real 2021 dollars, unless noted otherwise. In many cases, we provide 15-year (2021–2035) levelized values of avoided costs for ease of reporting and comparison with earlier AESC studies. See Appendix E: *Common Financial Parameters* for more information on financial parameters used in this analysis.

1.1. Background to the AESC Study

As in previous AESC studies, the AESC 2021 Study was sponsored by a group of electric and gas utilities and other efficiency program administrators (together, referred to as program administrators). The study sponsors, along with other parties (including representatives from state governments, consumer advocacy organizations, and environmental advocacy organizations and their consultants) formed a Study Group to oversee the design and production of the analysis and report.

Study sponsors for the AESC 2021 Study include: Berkshire Gas Company, Cape Light Compact, Liberty Utilities, National Grid USA, Eversource (Connecticut Light and Power, NSTAR Electric and Gas Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas), New Hampshire Electric Co-op, Columbia Gas of Massachusetts, Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc. and Northern Utilities), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, Efficiency Maine, and the State of Vermont. Other parties represented in the Study Group include: Acadia Center, Connecticut Department of Energy and Environmental Protection, Connecticut Energy Efficiency Board, Maine Public Utilities Commission, Massachusetts Energy Efficiency Advisory Council, Massachusetts Clean Energy Center, Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Department of Environmental Protection, Massachusetts Attorney General, Massachusetts Low-Income Energy Affordability Network (LEAN), New Hampshire Office of Consumer Advocate, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Rhode Island Energy Efficiency and Resource Management Council, Rhode Island Office of Energy Resources, Vermont Department of Public Service, and Vermont Energy Investment Corporation / Efficiency Vermont.

After developing the scope for the 2021 study, the study sponsors selected Synapse Energy Economics (Synapse) as the lead contractor of the study. Synapse was joined by subcontractors Resource Insight, Sustainable Energy Advantage, Les Deman Consulting, and North Side Energy (together, the Synapse Team).

[1] This extrapolation is described in detail in Appendix A: *Usage Instructions*.

1.2. Summary of avoided costs

The following section provides a summary of the avoided costs for each category of costs calculated under the AESC 2021 Study. These categories include costs that can be applied to energy efficiency measures that avoid electricity (energy, capacity, DRIPE, RPS, etc.) while others are related to energy efficiency measures that avoid other types of energy consumption. ES-Table 1 provides an illustration of summer on-peak avoided cost components for electricity for the West/Central Massachusetts (WCMA) zone for Counterfactual #1, and how these components compare to the avoided costs from the previous AESC 2018 study for informational purposes. ES-Table 2, ES-Table 3, and ES-Table 4 provide analogous comparative information for Counterfactuals #2, #3, and #4, respectively.

In general, the Synapse Team finds that lower wholesale natural gas prices drive lower avoided energy costs, relative to AESC 2018. We also find that avoided cost of RPS compliance in AESC 2021 are generally higher than those projected in AESC 2018. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification). We find that projections of flatter supply curves in future years cause avoided capacity, energy DRIPE, and capacity DRIPE values to be lower.

Note that comparisons between 15-year levelized costs in AESC 2021 and AESC 2018 are not directly "apples-to-apples." While both calculations display levelized costs over 15 years (in real 2021 dollars), each levelization calculation is done over two different 15-year periods (2018 to 2032 for AESC 2018, and 2021 to 2035 for AESC 2021). Assumptions on prices and loads aside, the time periods spanned by each of these levelization calculations may contain fundamentally different data on the New England electric system, including differences in terms of online units and market rules.

ES-Table 1. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #1 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.18	-0.93	-44%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.85	-1.48	-28%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.28	0.86	208%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.30**	**-1.55**	**-20%**	
GHG non-embedded	**2.69**	**2.83**	**4.74**	**1.91**	**67%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.20	-0.99	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.61**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.77**	**-1.72**	**-10%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $49/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $12/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 2. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #2 versus AESC 2018

	AESC 2018	**AESC 2018**	**AESC 2021**	**AESC 2021, relative to AESC 2018**		***Notes***
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.16	-0.95	-45%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.63	-1.69	-32%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	0.98	0.56	136%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**5.77**	**-2.08**	**-26%**	
GHG non-embedded	**2.69**	**2.83**	**5.08**	**2.25**	**79%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-33%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.39	-0.64	-62%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.08	-1.11	-51%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.47**	**-1.75**	**-54%**	**-**
Total	**15.68**	**16.49**	**14.43**	**-2.05**	**-12%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $48/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $31/MWh
9. Avoided RPS compliance cost of $9/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.46/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 3. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #3 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.22	-0.88	-42%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.92	-1.40	-26%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.40	0.98	237%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.54**	**-1.31**	**-17%**	
GHG non-embedded	**2.69**	**2.83**	**4.68**	**1.85**	**65%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.21	-0.98	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.62**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.96**	**-1.52**	**-9%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $51/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $13/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 4. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #4 versus AESC 2018

	AESC 2018 *2018 cents/kWh*	AESC 2018 *2021 cents/kWh*	AESC 2021 *2021 cents/kWh*	AESC 2021, relative to AESC 2018 *2021 cents/kWh*	*% Difference*	*Notes*
Avoided Retail Capacity Costs	2.00	2.11	1.22	-0.89	-42%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.90	-1.42	-27%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.40	0.98	237%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.52**	**-1.33**	**-17%**	
GHG non-embedded	**2.69**	**2.83**	**4.69**	**1.86**	**66%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.21	-0.98	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.62**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.94**	**-1.54**	**-9%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $50/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $13/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

Natural gas

At a high level, AESC 2021 assumes that Henry Hub natural gas prices are lower, and stay lower longer, relative to the assumptions used in AESC 2018. The levelized price basis for the New England market, as measured by the Algonquin Citygate price, is also lower.

On a 15-year levelized basis (see ES-Table 5), AESC 2021 projects a Henry Hub price of $3.15 per MMBtu (levelized over 2021 to 2035), 34.0 percent lower than the AESC 2018 value of $4.78 per MMBtu (levelized over 2018 to 2032). We attribute the decrease in Henry Hub prices to higher volumes of associated gas production and another downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions compared to AESC 2018.[2] Breakeven costs have been on a downward trend as a result of improvements in horizontal drilling technology and better information on the geology and geophysics of shale reservoirs.[3] Algonquin Citygate Hub prices show a slightly larger decline because the basis projections are lower in AESC 2021 (a smaller differential to Henry Hub) as a result of additional pipeline capacity and changing pricing dynamics between northeast and Gulf Coast gas markets.

ES-Table 5. Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials for AESC 2021 and AESC 2018

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2018 (2018–2032)	2021 $/MMBtu	$4.78	$6.59	$1.24
AESC 2021 (2021–2035)	2021 $/MMBtu	$3.15	$4.20	$1.05
Percent change	%	-34.0%	-36.2%	-

Notes: All values are in 2021 $/MMBtu. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2018 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

The avoided costs of natural gas for retail customers are summarized below (see ES-Table 6). For both southern New England and northern New England avoided natural gas costs are lower in AESC 2021 compared to AESC 2018, but because pipeline expansion costs are assumed to be higher, the change in avoided costs is not as large as the reduction in wholesale commodity prices. Northern New England avoided costs remain slightly lower relative to southern New England because natural gas delivered through Canada has become a significant marginal resource, as new pipeline capacity from the Marcellus Shale region has reduced the Dawn Hub price basis compared to the Henry Hub. Since the northern New England market is closer to this source of supply, the avoidable pipeline delivery cost is lower than it is for southern New England. For Vermont (not shown in ES-Table 6) avoided natural gas costs are also lower than in AESC 2018 because of lower projected natural gas prices at the Dawn Hub.

[2] Associated gas is essentially a byproduct in the production of crude oil. This gas will be produced (or flared) as long as oil production is economic, irrespective of the price of natural gas.

[3] U.S. Energy Information Administration (EIA). "Drilling Productivity Report." https://www.eia.gov/petroleum/drilling/. February 16, 2021.

ES-Table 6. Avoided costs of gas for all retail customers by end-use assuming no avoidable margin

	Units	Southern New England	Northern New England
AESC 2018 (2018–2032)	2021 $/MMBtu	$7.91	$7.57
AESC 2021 (2021–2035)	2021 $/MMBtu	$6.48	$6.39
Percent change	%	-18%	-16%

Note: AESC also calculates the avoided cost of gas for retail customers assuming some avoidable margin, and avoided costs for customers in Vermont. This additional detail is described in Chapter 0:

Avoided Natural Gas Costs.

ES-Table 8 compares the natural gas avoided costs described in ES-Table 6 with a non-embedded cost for GHGs. For consistency with ES-Table 1 and other similar tables, the non-embedded GHG cost shown here is the marginal abatement cost derived from the New England electric sector. We observe that the non-embedded GHG cost is roughly equal to the avoided cost of natural gas, which matches our observations in ES-Table 1, where the non-embedded cost is slightly greater than the avoided cost of energy.

ES-Table 7. Avoided costs of gas, with and without non-embedded GHG cost

	Units	Southern New England	Northern New England
Avoided cost (from ES-Table 6)	2021 $/MMBtu	$6.48	$6.39
Non-embedded GHG cost	2021 $/MMBtu	$7.32	$7.32
Avoided cost with non-embedded GHG cost	2021 $/MMBtu	$13.80	$13.71

Note: Avoided costs differ depending on region, and whether or not retail margins are included. The "non-embedded GHG cost" shown here is the marginal abatement cost derived from the New England electric sector.

Fuel oil and other fuels

In general, we find that avoided levelized costs for residential fuel oil and other fuels are generally higher than was estimated in AESC 2018, except for the levelized costs for commercial residual fuel oil and biofuels which are lower than was estimated in AESC 2018. The primary sources of these differences are changes in historical prices from the State Energy Data System (SEDS) and changes in the projected price of crude oil, which underlies many of the cost projections. ES-Table 8 displays the levelized avoided fuel costs for AESC 2021. New in AESC 2021 are avoided cost projections for motor gasoline and motor diesel.

ES-Table 8. Avoided costs of retail fuels (15-year levelized, 2021 $ per MMBtu)

	Residential						Commercial		Transportation	
	No. 2 Distill-ate	Pro-pane	Kero-sene	Bio-Fuel (B20)	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Resid-ual	Motor Gasoline	Motor Diesel
AESC 2018	$23.36	$32.78	$20.95	$24.06	$14.12	$22.76	$19.46	$17.13	-	-
AESC 2021	$24.04	$38.79	$29.59	$21.64	$20.84	$22.47	$22.25	$15.74	$22.07	$22.76
Percent change	2.9%	18.3%	41.3%	-10.1%	47.6%	-1.3%	14.3%	-8.2%	-	-

The retail fuels avoided costs for AESC 2021 are similar to those of AESC 2018 for distillate fuels. The more significant differences between AESC 2021 and AESC 2018 observed in other fuels are primarily driven by changes in the starting prices based on recent historical data. There have been significant residential price increases for propane in recent years, perhaps associated with distribution costs. For non-wood products, AESC 2021 starts with the 2018 New England fuel prices in the U.S. Energy Information Administration (EIA) State Energy Data System (SEDS). It then makes adjustments to match the most recent national prices from the EIA Short Term Energy Outlook (STEO). For the near term, fuel oil prices follow the STEO's crude oil price forecast for 2021. Meanwhile, for 2022 and later years, we rely on projections in the AEO 2021 Reference case. For biofuels, the B20 blend shown in the table is discounted at about 10 percent below distillate. All sector propane prices are consistently higher than distillate prices for all years in SEDS.

For residential wood fuels, AESC 2021 surveyed various state energy sources, which gave much higher cord wood prices than those used in AESC 2018. Wood pellet prices were however about the same. Wood prices are then projected to increase in the future following the trend in crude oil prices reflecting competitive market factors.

Capacity

AESC 2021 develops capacity prices for annual commitment periods starting in June 2021 under each of the four counterfactuals (see ES-Table 9). The capacity prices (and resulting avoided capacity costs) are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market (FCM). The forecast capacity prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules. These prices are applied differently for cleared resources, non-cleared energy efficiency, and non-cleared demand response.

On a 15-year levelized basis, Counterfactual #1 of the AESC 2021 forecast is 47 percent lower than what was estimated as a 15-year levelized price in the 2018 AESC study. Counterfactual #2 is 48 percent lower, while Counterfactual #3 and #4 are both 45 percent lower. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while Counterfactuals #1, #3, and #4 feature relatively similar capacity prices, due to similar projections of annual loads. Market-clearing prices in the out-years are principally determined by future changes in supply (including additions of battery storage, solar, wind, and occasionally new natural gas-fired power plants; as well as and retirements of thermal generation) and future changes in demand. Small year-on-year variations are due to changes in load, new resources coming online, and other resources retiring.

ES-Table 9. AESC 2018 capacity prices (2021 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2020 EE	AESC 2021				AESC 2018
				Counter-factual #1	Counter-factual #2	Counter-factual #3	Counter-factual #4	
2021/2022	12	$4.63	$4.77	$4.77	$4.63	$4.77	$4.77	$4.99
2022/2023	13	$3.73	$3.96	$3.96	$3.73	$3.96	$3.96	$5.10
2023/2024	14	$1.92	$2.47	$2.47	$1.92	$2.47	$2.47	$5.21
2024/2025	15	$2.46	$2.75	$2.75	$2.46	$2.75	$2.75	$5.50
2025/2026	16			$2.72	$2.69	$2.59	$2.59	$5.95
2026/2027	17			$2.88	$2.69	$2.75	$2.75	$6.46
2027/2028	18			$3.11	$3.33	$3.46	$3.43	$6.95
2028/2029	19			$3.30	$3.30	$3.65	$3.62	$7.45
2029/2030	20			$3.59	$3.41	$3.94	$3.92	$7.95
2030/2031	21			$3.42	$3.77	$3.97	$3.94	$6.95
2031/2032	22			$3.67	$3.81	$3.79	$3.77	$7.45
2032/2033	23			$3.90	$3.86	$4.02	$3.99	$7.95
2033/2034	24			$3.86	$4.02	$3.95	$3.92	$6.95
2034/2035	25			$4.67	$4.47	$5.09	$4.95	$7.45
2035/2036	26			$3.66	$3.86	$3.73	$3.71	$7.95
15-year levelized cost				**$3.51**	**$3.45**	**$3.65**	**$3.63**	**$6.63**
Percent difference				**-47%**	**-48%**	**-45%**	**-45%**	

Notes: Levelization periods are 2021/2022 to 2035/2036 for AESC 2021 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 0.81 percent for AESC 2021 and 1.34 percent for AESC 2018.

Energy

AESC 2021 modeling results feature a lower ratio of summer peak prices to the annual average compared to previous AESC studies. This difference can be attributed to: (1) increased levels of solar generation, which are largely coincident with this period and which have a marginal cost of zero dollars per MWh, (2) difference in month-to-month wholesale gas costs (which are driven by new recent historical data on month-to-month gas costs), and (3) higher levels of zero-marginal cost imports. These are the same factors that drove the change in energy prices in AESC 2015 and AESC 2018.

ES-Table 10 shows levelized costs (over 15 years) for the WCMA reporting region. Prices are shown for all hours, and for the four conventional AESC costing periods. On an annual average basis, the 15-year levelized prices in Counterfactual #1 of the AESC 2021 study are 20 percent lower than the prices modeled in the 2018 AESC study. Key drivers of these lower prices include lower Henry Hub natural gas prices, lower RGGI prices, more low- or zero-variable operating cost renewables (caused by changes to the RPS in states like Connecticut and Rhode Island), and the addition of a new transmission line from Canada. Note that these factors are not listed in a particular order. Energy prices observed in other counterfactuals are similar to Counterfactual #1. Counterfactual #2 features the largest divergence, as a result of its lower projection of load. This decrease is larger than the change in avoided energy costs observed between the 2015 AESC study and the 2018 AESC study.

ES-Table 10. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	$51.17	$58.66	$54.17	$45.22	$38.69
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
AESC 2021 Counterfactual 4	$41.29	$47.40	$45.62	$33.17	$29.87
Pcnt Change: Counterfactual 1	-20%	-20%	-17%	-28%	-23%
Pcnt Change: Counterfactual 2	-26%	-27%	-23%	-32%	-28%
Pcnt Change: Counterfactual 3	-19%	-19%	-16%	-26%	-23%
Pcnt Change: Counterfactual 4	-19%	-19%	-16%	-27%	-23%

Notes: All prices have been converted to 2021 $ per MWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Prices are wholesale.

ES-Table 11 compares 15-year levelized costs between AESC 2018 and AESC 2021 for each of the six New England states, for Counterfactual #1. These values incorporate the relevant costs of RPS compliance, as well as a wholesale risk premium.

ES-Table 11. Avoided energy costs, AESC 2021 vs. AESC 2018 (15-year levelized costs, 2021 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	1	Connecticut	$0.059	$0.057	$0.043	$0.040
	2	Massachusetts	$0.062	$0.060	$0.047	$0.044
	3	Maine	$0.057	$0.056	$0.042	$0.039
	4	New Hampshire	$0.058	$0.057	$0.043	$0.040
	5	Rhode Island	$0.065	$0.064	$0.050	$0.047
	6	Vermont	$0.054	$0.053	$0.039	$0.036
AESC 2018	1	Connecticut	$0.063	$0.059	$0.049	$0.043
	2	Massachusetts	$0.062	$0.058	$0.049	$0.043
	3	Maine	$0.058	$0.054	$0.045	$0.039
	4	New Hampshire	$0.063	$0.060	$0.051	$0.044
	5	Rhode Island	$0.061	$0.057	$0.048	$0.042
	6	Vermont	$0.062	$0.058	$0.049	$0.042
Delta	1	Connecticut	-$0.005	-$0.002	-$0.006	-$0.003
	2	Massachusetts	-$0.001	$0.003	-$0.002	$0.001
	3	Maine	$0.000	$0.002	-$0.003	$0.000
	4	New Hampshire	-$0.005	-$0.003	-$0.008	-$0.004
	5	Rhode Island	$0.003	$0.007	$0.002	$0.005
	6	Vermont	-$0.008	-$0.005	-$0.010	-$0.006
Percent Change	1	Connecticut	-7%	-3%	-12%	-7%
	2	Massachusetts	-1%	5%	-4%	2%
	3	Maine	0%	4%	-6%	1%
	4	New Hampshire	-8%	-5%	-15%	-8%
	5	Rhode Island	6%	12%	5%	12%
	6	Vermont	-13%	-8%	-20%	-14%

Notes: These costs are the sum of wholesale energy costs and wholesale costs of RPS compliance, increased by a wholesale risk premium of 8 percent, except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2021 dollars per kWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Values do not include losses.

RPS compliance

Relative to AESC 2018, AESC 2021 sees much higher prices for meeting RPS compliance (see ES-Table 12). This difference is attributable to increased supply-demand tension in the near term, resulting in higher REC prices compared to AESC 2018, particularly for states that have recently adjusted their RPS policies. Even with higher prices, the remainder of the study period is characterized by surplus, with policy-mandated purchases exceeding incremental RPS demands. The cost of RPS compliance has also increased as a result of the addition of new RPS categories such as Clean Energy Standard-Existing (CES-E) and Clean Peak Energy Portfolio Standard (CPS) categories in Massachusetts. Increases in the cost of RPS compliance in states that have not increased RPS targets (e.g., New Hampshire) are due to an increase in REC demand in the New England-wide REC market, of which all six states are participants.

ES-Table 12. Avoided cost of RPS compliance (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
AESC 2018	$4.00	$0.55	$3.84	$5.25	$2.57	$2.12
AESC 2021 Counterfactual 1	$7.93	$7.37	$11.81	$8.10	$14.99	$3.90
AESC 2021 Counterfactual 2	$4.77	$3.55	$9.04	$6.41	$5.66	$2.67
AESC 2021 Counterfactual 3	$8.84	$8.56	$12.93	$8.67	$16.81	$4.44
AESC 2021 Counterfactual 4	$8.84	$8.56	$12.93	$8.67	$16.81	$4.44
Pcnt Change: Counterfactual 1	98%	1233%	208%	54%	482%	84%
Pcnt Change: Counterfactual 2	19%	541%	135%	22%	120%	26%
Pcnt Change: Counterfactual 3	121%	1448%	237%	65%	553%	110%
Pcnt Change: Counterfactual 4	121%	1448%	237%	65%	553%	110%

Note: Each state has multiple Classes or Tiers. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. AESC 2018 values are from AESC 2018 Chapter 7, and have been converted into 2021 dollars. All values include a 9 percent loss factor.

Non-embedded environmental compliance

AESC 2021 provides several approaches to enable individual states to address specific policy directives regarding greenhouse gas (GHG) impacts. ES-Table 13 and ES-Table 14 compare these costs.

- A "damage cost" approximated by the social cost of carbon (SCC). There are many different options for a social cost of carbon. The Synapse Team recommends using a value that applies low discount rates, considers global damages, and considers the impact of high-risk situations. One source for this value is the December 2020 SCC Guidance published by the State of New York. Using a 2 percent discount rate (the one also recommended by New York for most decision-making), we recommend a 15-year levelized SCC of $128 per short ton in AESC 2021. We also recommend that program administrators continually review this value (e.g., for the purposes of mid-term modifications) as updates to the federally-recommended SCC are expected in early 2022.

- An approach based on global marginal abatement costs. In AESC 2021, we estimate a total environmental cost based on the cost of large-scale carbon capture and sequestration (CCS) equal to $92 per short ton of CO_2-eq. This is lower than the $105 per short ton of CO_2-eq value (in 2021 dollars) described in AESC 2018. This lower cost reflects the declining costs of this technology.

- An approach based on New England marginal abatement costs, assuming a cost derived from electric sector technologies. In AESC 2021, this is a total environmental cost of $125 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard. This compares to a cost of $72 per short ton of CO_2-eq emissions (in 2021 dollars) based on a projection of future costs of offshore wind energy, as described in AESC 2018. This increased cost reflects updated information on this technology in the United States, as well as lower energy costs in this edition of AESC.

- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors. In AESC 2021, this is a total environmental cost of $493 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for renewable natural gas (RNG) derived from power-to-gas technology. This approach may be useful for policymakers who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050).

ES-Table 13. Comparison of GHG costs under different approaches (2021 $ per short ton) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	$128	-	-
Global marginal abatement cost	$105	$92	-$13	-12%
New England-based marginal abatement cost, derived from the electric sector	$72	$125	$53	75%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	$493	-	-

Notes: All values shown are levelized over 15 years. All AESC 2021 values except the SCC are levelized using a 0.81 percent discount rate (SCC uses a 2.0 percent discount rate). All AESC 2018 values are levelized using a 1.34 percent discount rate, then converted into 2021 dollars. In AESC 2018, damage costs were discussed, but not quantified. AESC 2018 did not discuss or estimate a New England-based marginal abatement cost derived from multiple sectors. Values shown above remove energy prices, but not embedded costs. Values shown above do not include losses.

ES-Table 14. Comparison of GHG costs under different approaches (2021 cents per kWh) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	4.87	-	-
Global marginal abatement cost	4.64	3.41	-1.23	-26%
New England-based marginal abatement cost, derived from the electric sector	2.83	4.74	1.91	67%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	19.72	-	-

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75. All values are quoted using a summer on-peak seasonal marginal emission rate, and include a 9 percent energy loss factor.

In addition, AESC 2021 establishes a non-embedded NO_X emission cost of $14,700 per short ton, based on a review of findings in the literature, which translates into an avoided wholesale cost for NO_X of $0.77 per MWh.

DRIPE

DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Reference case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs.

Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

AESC 2021 models DRIPE benefits associated with reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets. DRIPE results in AESC 2021 differ from those in AESC 2018 because of updated information changes in utility long-term energy purchases, updated market data, and new commodity forecasts. Generally speaking, we find (a) lower energy DRIPE and capacity DRIPE values, due to projections of flatter supply curves compared to AESC 2018, (b) lower natural gas DRIPE values due to lower commodity prices and flatter supply curves, and (c) lower oil DRIPE values, due to changes in the underlying projection of crude oil prices.

Transmission and distribution

In AESC 2021, we present four separate threads for analysis of avoided transmission and distribution (T&D) costs, building on the foundation established in the 2018 AESC and updating or expanding the analysis presented. The four aspects are:

1. Updating the avoided costs for PTF facilities based on future costs;
2. Reviewing utility approaches to generic avoided cost values for non-PTF transmission and distribution and evaluating these approaches on a common evaluation rubric to facilitate cross-comparison and learning;
3. Reviewing utility approaches to calculating geographically localized avoided costs, such as for non-wire alternatives (NWA); and
4. Developing an approach to the avoided cost of natural gas system T&D.

Of these items, only the first was performed in AESC 2018. In that study, we found the PTF cost to be $99 per kW-year (in 2021 dollars). In AESC 2021, we find the PTF value to be $84 per kW-year, a decrease of 15 percent. This change is due to a switch to a forward-looking methodology, versus the historical cost methodology used in AESC 2018.

Reliability

As in AESC 2018, AESC 2021 examines how changing electric load levels can change reliability in several ways, which differ among generation, transmission, and distribution. Our analysis addresses the effect of increased reserve margins based on generation reliability, the potential and obstacles in estimating the effect of load levels on T&D overloads and outages, and VoLL. We then develop estimates of the value of increased generation reliability per kilowatt of peak load reduction.

In AESC 2021, we find a default average VoLL value of $73 per kWh. This value is almost three times as large as the value derived in AESC 2018 ($26 per kWh in 2021 dollars). The change in the VoLL component is a result of updated information on VoLLs. This VoLL is then applied to the calculation of reliability benefits resulting from dynamics in New England’s FCM to estimate cleared and uncleared benefits linked to improving generation reliability. In AESC 2021, we find 15-year levelized values of

$0.47 per kW-year for cleared benefits and $8.45 per kW-year for uncleared benefits. These are 32 percent lower and 21 percent higher, respectively, than the same values estimated in AESC 2018, after adjusting for inflation. For cleared reliability, despite a higher VoLL, overall benefits are lower as a result of flatter supply curve assumptions for the capacity market. Changes to the capacity market have less of an impact on uncleared resources, which exist outside the capacity market. As a result, an increase in the VoLL produces an increase in the uncleared reliability value.

New in AESC 2021, we provide an example methodology to estimate benefits related to T&D reliability This estimate is based on data for National Grid Massachusetts. This value would likely differ for each jurisdiction. As a result, the methodology provided can be interpreted as guidance for calculating avoided costs.

Sensitivities

The following sections detail the inputs and results of the sensitivity analysis. In AESC 2021, we evaluate avoided costs under three different sensitivities. These sensitivities include:

- A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 (“High Gas Price Sensitivity”)
- A climate policy sensitivity, where avoided costs for energy efficiency are calculated under a hypothetical regional climate policy with increased levels of electrification and clean energy (“No New EE Climate Policy Sensitivity”)
- A climate policy sensitivity which models energy efficiency along with increased levels of electrification and clean energy (“All-In Climate Policy Sensitivity”)

For each of these sensitivity cases, we find the following:

- In the High Gas Price Sensitivity, energy prices are 27 percent higher, capacity prices are 2 percent lower, RPS compliance costs are 8 percent lower, and non-embedded GHG costs are 21 percent lower. All prices are compared to Counterfactual #1.[4]
- In the No New EE Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 52 percent higher, and RPS compliance costs are 12 percent higher. All prices are compared to Counterfactual #3. This sensitivity features a new avoided cost (the incremental regional clean energy policy compliance cost, or IRCEP), which captures the incremental cost of the region reaching 90 percent non-fossil generation by 2035. This category increases total levelized avoided costs by 0.9 percent
- In the All-In Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 42 percent higher, and RPS compliance costs are 11 percent higher. All prices are

[4] All of the summary costs described here are framed in terms of 15-year levelized costs for summer on-peak for the WCMA region.

compared to Counterfactual #2. The new IRCEP cost category increases total avoided costs by 0.4 percent, all else being equal.

In the High Gas Price Sensitivity, energy prices are higher due to higher gas prices, which is the fuel that powers the marginal resource in most hours. The non-embedded GHG cost is lower because one of the inputs to this value is the energy price (in situations like this one, where the non-embedded GHG cost is based on the New England-derived marginal abatement cost). Generally speaking, higher energy prices will produce lower non-embedded GHG costs.

In the climate policy sensitivities, we find that energy prices typically only have minor changes relative to the comparative counterfactual. Capacity prices tend to be much higher, and are largely caused by high capacity prices in the early- to mid-2030s. In these years, the system switches to winter peaking and demand increases quickly. Costs of RPS compliance are also higher due to increased demand for electricity. Finally, we find that the additional cost of compliance associated with the region reaching 90 percent non-fossil generation by 2035 is low, on a levelized basis. This is due to several factors, including the fact that many states in New England are already reaching very high non-fossil percentages by 2035, and because the cost of compliance is zero in the near term (as the policy does not come into effect until the mid-2020s).

2. AVOIDED NATURAL GAS COSTS

The following sections first discuss the drivers of natural gas commodity prices (i.e., the long-term price for natural gas at Henry Hub and other price points upstream of New England). The wholesale natural gas price is the market price of gas that is sold to local distribution companies (LDC), electricity generators, and other large end-users at interstate pipeline delivery points. The discussion then addresses factors impacting the price basis for natural gas sold in New England and ends with a discussion of the methodology used to quantify avoided costs of natural gas. The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the LDC (the "citygate cost"); and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). As with previous versions of AESC, natural gas avoided costs are presented with and without the retail margin.

Natural gas prices in AESC 2021 are significantly lower than in AESC 2018. Lower price forecasts have been a persistent trend over the past decade as a result of assumptions in the AEO Reference cases that were too conservative in terms of shale gas reserves, productivity, drilling costs, and production growth.

2.1. Introduction

The dampening effect of the COVID-19 pandemic on end-use consumer demand for natural gas and other fuels resulted in 2020 experiencing the lowest Henry Hub prices in over two decades. Producers reacted to this reduction in demand by shutting-in production and reducing drilling. However, low gas prices caused natural gas-fired generation to take market share from coal-fired electric generation and made liquified natural gas (LNG) exports from the United States highly attractive. As a result, total demand for natural gas in 2020 was nearly identical to 2019. As the supply-demand balance began to tighten in the fall of 2020, Henry Hub prices began to escalate, providing producers an incentive to increase drilling and production, but dampening the economics of gas-fired electric generation. Against this backdrop, the latest Annual Energy Outlook (AEO), published by the EIA in early February 2021, projects a slow return to "normal," indicating long-lasting effects on the energy sector from the COVID-19 pandemic. AEO projects that it will take until 2023 for natural gas production to return to its pre-pandemic peak, and that it will take until 2026 for domestic consumption to reach a new peak. Over the longer term, the projections for gas prices in AEO 2021 are not substantially different than prices projected in AEO 2020.

Responses to the pandemic in the physical natural gas market were not mimicked by the financial market or trading activity during 2020. This meant that trading was not substantially different from the prior year's record high activity.[5] AEO 2021 projects that prices will begin a sustained rebound in 2025 as

[5] While Federal Energy Regulatory Commission (FERC) Form 552 filings reported record volumes in 2019, Chicago Mercantile Exchange (CME) and Intercontinental Exchange (ICE) reported slightly lower trading volumes. Natural gas is also traded on other platforms, such as NASDAQ.

producers pursue less-economic reserves. Prices and financial trading volumes continue to indicate a very active market, anchored by NYMEX Henry Hub futures.[6] Although prices and outlooks fluctuate, there remains an active wholesale natural gas market in New England for gas that is sold to LDCs, electricity generators, and other large end-users at interstate pipeline delivery points. Note that recent energy market disruptions and macroeconomic impacts due to the COVID-19 pandemic widen the uncertainty band of any price forecast.[7]

2.2. Gas prices and commodity costs

The following sections provide an overview of historical natural gas prices and projected future wholesale natural gas prices.

Background

The U.S. fuel extraction industry appeared past its prime at the start of the 21st century, but early in the 2010s, shale gas and oil suddenly became an industry with significant growth potential. Order-of-magnitude drilling economics improvements have changed the market's perception of both natural gas and crude oil from increasing-cost commodities to flat-to-declining-cost commodities. Capital became widely available to small- and medium-sized companies willing to expand drilling in new shale and tight-sand formations, to build new processing and transport infrastructure, and to consume growing gas volumes in domestic sectors or export the surplus to growing overseas LNG markets. Indeed, in 2000 the United States consumed about 64 billion cubic feet per day (Bcfd) of natural gas, of which 10 Bcf per day was imported, while in 2020 consumption was about 83 Bcfd and over 7 Bcfd was exported.[8]

In the three years since the AESC 2018 analysis, these trends have been extended through significant production growth, mainly in Texas and Appalachia. This time period has also seen increasing domestic consumption, mainly through electric generation, and surging exports of LNG which are primarily from new terminals on the Gulf Coast and Eastern Seaboard. However, the upstream (production) side has seen a geographical shift. Natural gas in Appalachia had been in surplus for several years because of lags

[6] NYMEX Henry Hub futures prices are traded for 120 months out. There are also futures prices and price differentials (basis) for other regional natural gas hubs traded on the NYMEX or other organized exchanges. Cornerstone Research: *Characteristics of U.S. Natural Gas Transaction* (Jul 2020) reported that trading volumes during the first of this year indicate and increase in 2020; p. 10.

[7] Prices quoted on the NYMEX and other active futures exchanges represent a collective market view of supply and demand conditions in the future. However, there is a risk when using any price forecast in business decisions. Physical players such as LDCs and producers purchase or sell futures to hedge price risk. A futures contract provides insurance against price volatility. Buying and selling entities including traders know they run the risk that they will incur an opportunity cost—buying or selling at too low or too high a price. To many, this is an acceptable risk, giving up potential profits for a known price. Others may prefer purchasing derivative financial instruments that can be used to cover some of the opportunity cost risks; for example, protective collars can be purchased that provide additional downside or upside price protection, and the risk of purchasing too much or too little gas due to adverse weather can be hedged via weather derivatives.

[8] U.S. EIA, *Natural Gas Annual*, available at https://www.eia.gov/naturalgas/annual/. The 2019 edition was released on September 30, 2020. Historical data is published in the EIA's *Monthly Energy Review*.

in pipeline infrastructure, resulting in falling prices in the region. Simultaneously, high oil prices created a boom in shale oil plays, mainly in the Permian Basin. Surging oil production also resulted in a large increase in associated gas production.[9] Since the beginning of 2018, Permian gas production has more than doubled, compared to a 30 percent increase in Appalachian volumes. However, drilling activity dropped sharply in the second and third quarters of 2020 resulting in a decline in associated gas production and a flattening of Appalachian output.

All the primary gas markets were affected by these production shifts, by new infrastructure, and by new gas-fired electric generation. In New England, for example, gas-fired power now accounts for about half of the installed generating capacity in the six-state region, which is three times what it was 20 years ago. Volumes also increased at most gas trading hubs and the ability to arbitrage regional price differentials rose with additional pipeline capacity and new commodity trading platforms. Although a few small, incremental pipeline projects were added over the past few years, New England avoided large-scale investments in natural gas infrastructure; nonetheless, the region still exhibited a downward gas price trend over the past decade.

Over the past two years, the New England gas market has seen a small increase (see Section 2.3. *New England natural gas market*). However, the primary sources of gas supply to New England and the delivery pipelines are unchanged. As in prior AESC studies, we conclude that there are three main components to New England gas costs.

1. The natural gas price at the point of purchase at a market trading hub or at the production site (the "supply area" price or "commodity cost");
2. The pipeline transportation cost from the trading hub or supply area to the LDC citygate or electric generating plant; and
3. The retail distribution margin from the citygate to the end-user's burner tip.

Supply area natural gas prices

Natural gas consumed in New England is sourced from various points in the United States and Canada. These sources vary depending on the purchasing entity and contractual arrangements, as well as seasonal differences such as storage and LNG. Gas is purchased at hubs in New England, such as the Algonquin (AGT) Hub, or hubs further south, in Canada, or in other locations. As in the rest of North America, because of the integrated pipeline network, gas prices in New England are strongly correlated to the Henry Hub benchmark. Therefore, similar to previous AESC studies, Henry Hub serves as the foundation for developing price projections relevant to New England markets. The rationale for this choice is that Henry Hub has been the U.S. gas price benchmark since the early 1990s and is likely to continue that role in the foreseeable future. There are many reasons for choosing Henry Hub.

[9] Associated natural gas or associated-dissolved natural gas is natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).

1. Foremost, perhaps, is that it the most highly traded natural gas pricing point in the United States. According to the Chicago Mercantile Exchange (CME), the NYMEX Henry Hub contract (symbol "NG") is the third-largest physical commodity futures contract in the world by volume.[10] The New York Mercantile Exchange (NYMEX) trades Henry Hub monthly gas with contracts extending for 120 months.

2. Many natural gas purchase and sales contracts for natural gas are tied to the NYMEX Henry Hub price because of transparency and liquidity. Moreover, they allow market participants the ability to hedge and to manage risk.

3. For many of the other trading points (hubs) throughout the United States, Henry Hub serves as the derivative pricing market in the form of basis trades, i.e., the difference between the Henry Hub price and the price at a different hub.

4. EIA (in the AEO) and many other organizations base their price forecasts on Henry Hub.

5. The burgeoning surplus of gas in Appalachia and other regions is being increasingly funneled to LNG export terminals along the Gulf Coast (Texas and Louisiana). From the end of 2017 through 2020, export capacity has increased from roughly 3 Bcfd to 10 Bcfd. Nearly 10 percent of U.S. gas demand now comes from LNG exports, with the bulk of that along the Gulf Coast. Pipelines have correspondingly increased capacity to meet this demand. Even more LNG export capacity is in the planning stage. The AEO and most other forecasts envision that LNG exports will be the marginal market for natural gas at least over the next decade and that the Henry Hub pricing point in Louisiana will be a primary signal in this new market dynamic.

Although natural gas prices quoted by the NYMEX are volatile, they represent the current collective wisdom of the gas market. Prices change daily as physical buyers and sellers and financial players continually assess new data and reformulate expectations about the future gas market. Near-term factors such as storage balances, weather, and demand and supply expectations have a larger influence in the front of the price curve. These prices influence decisions by producers, consumers, and investors that can affect the future demand and supply balance. Most NYMEX participants are "hedgers" who use the futures market to reduce the risk of financial losses from price changes, i.e., lock-in a price to buy or sell gas. With more hedging in the winter months when gas demand peaks, there is marked seasonality in natural gas trading. Most hedging is short-term, i.e., over the next 12 to 18 months, so there is more liquidity (larger volume of transactions) in the near months of the natural gas market). Liquidity falls significantly beyond 18 months. Thus, similar to previous AESC studies, the short-term natural gas price forecast relies entirely on NYMEX Henry Hub futures. In addition, we use the seasonality in monthly prices observed in the 2022–2023 NYMEX futures complex to develop long-term monthly trends for the Henry Hub gas price over the 2021–2035 study period.

[10] Details on the NYMEX Henry Hub Contract can be found on the CME website: http://www.cmegroup.com/trading/energy/nymex-natural-gas-futures.html. There is seasonality in the 12-year NYMEX Henry Hub futures complex and we are using that seasonality to convert the annual AEO forecasts to monthly forecasts. CME data was downloaded for use in the AESC 2021 Study on February 1, 2021.

As with previous AESC studies, we rely on AEO for longer-term Henry Hub price forecasts. The most recent current AEO was published in February 2021 (AEO 2021).[11] There are numerous reasons for choosing AEO for longer-term price forecasts; foremost is the extensive documentation and transparency of the inputs and models used by EIA. There are many companies, consultants, and other organizations that forecast natural gas and other prices. However, there is no way to evaluate them without complete datasets, assumptions, or documentation on model algorithms.[12] The EIA forecasts are public, transparent, and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among various fuels. Previous AESC studies have relied on the AEO Reference Case, which generally assumes current legislation and environmental regulations. Specifically, AEO 2021 assumes government actions for which implementing regulations were available as of the end of September 2020 and macroeconomic assumptions based on third and fourth quarter 2020 assessments.[13] These macroeconomic assumptions include the effects of the COVID-19 pandemic on natural gas and other energy sectors.

EIA has recognized an increased level of uncertainty in its projections due to the impacts of the COVID-19 pandemic on energy markets and the wider economy.[14] The COVID-19 pandemic represents a novel forecasting challenge. As in previous outlooks, the Reference case for AEO 2021 is a projection rooted in experience to date and the current short- and medium-term economic outlook. But the influence of the pandemic in this forecast and the necessity of conjecturing what the recovery will look like means that the longer-term view may be particularly uncertain.

The Reference case in AEO 2021 anticipates that economywide demand for energy in the United States will not return to 2019 levels until 2029.[15] On average, the Henry Hub price forecast for the AEO 2021 reference case is approximately 2.6 percent lower than the corresponding forecast from AEO 2020. Meanwhile, alternative scenarios explored in AEO 2021 ("side cases") consider the impacts of differing economic growth rates resulting in a return to pre-pandemic economic activity and energy consumption levels in shorter or longer order.

For AESC 2021, we use the current NYMEX Henry Hub futures forecast for short-term prices (through 2023) and AEO 2021 for medium- and long-term prices.[16] We believe that the current NYMEX Henry Hub

[11] U.S. EIA. 2021. Annual Energy Outlook (AEO) 2021. https://www.eia.gov/outlooks/aeo/.

[12] AESC 2021 differs from its predecessors in that the timing of this year's study allows for the use of the most recent AEO projection. Previous AESC studies, by virtue of their study timeline, frequently used AEO projections that were a year or more out-of-date at the time of AESC's publication.

[13] Assumptions are documented in several reports. See EIA's AEO assumptions at https://www.eia.gov/outlooks/aeo/assumptions/.

[14] U.S. EIA, 2021. AEO 2021 narrative, p 4, at https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf.

[15] Ibid.

[16] The gas price forecast methodology employed in AESC 2021 differs from that of AESC 2018 only in that we do not transition from the NYMEX futures value, used for the preliminary forecast years, to the AEO forecast series for the later forecast years

price forecast incorporates an independent and collective view of the market supply and demand balances over the next three years. It also incorporates current expectations on the effects and duration of the COVID-19 pandemic. Meanwhile, AEO 2021 represents a neutral, third-party projection of Henry Hub prices based on recent trends and expectations, accounting for the COVID-19 pandemic, but ultimately reflecting conventional trends outlasting the impacts of the pandemic.[17] Factors influencing the longer-term forecasts of energy demand beyond the period of uncertainty associated with the COVID-19 pandemic include economic and population growth; increasing reliance on renewables and consumption of natural gas and electricity; and technological, behavioral, and policy shifts.

The following section provides highlights of the AEO 2021 Reference case and other AEO cases.

AEO 2021 Reference case

Compared to the recent past, the AEO 2021 Reference case projects the U.S. natural gas industry growing more slowly in the decades ahead. Gas production in the United States (dry gas) increased by 57 percent from 2010 to 2019 while AEO 2021 has production growing by only 23 percent from 2024–2050.[18] Similarly, consumption slows markedly in all sectors. The decline is most pronounced in the residential sector, which sees flat-to-declining gas use in the future.

In AEO 2021, real Henry Hub prices (in 2021 dollars) are projected to fall from $3.23 per MMBtu in 2021 to $2.78 per MMBtu in 2023. Prices then increase by 2.4 percent per year, reaching a price of $3.68 per MMBtu in 2035. Producers require higher prices to expand into less prolific and more expensive-to-produce areas to meet the growth in gas demand and LNG exports.

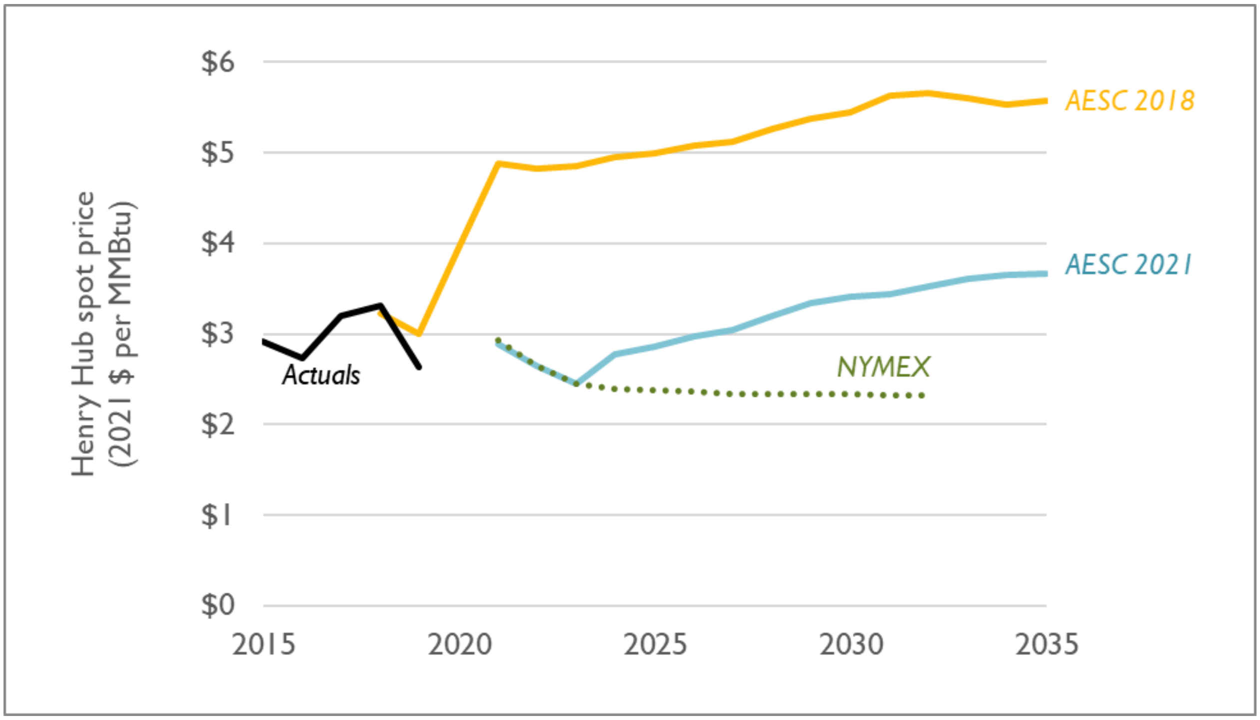
Figure 1 shows the forecast of Henry Hub prices used in AESC 2021. As described above, these rely on current NYMEX futures (dated February 1, 2021) for prices between 2021 and 2023. Prices in 2024 through 2035 are based on AEO 2021. Figure 1 also compares the Henry Hub price used in AESC 2021 with the price forecast used in AESC 2018 (in 2021 dollars).

with a bridge year calculated by averaging the two series. Instead, we transition directly from NYMEX futures (for 2021-2023) to the AEO forecast series (for 2024 and beyond).

17 Ibid.

18 "Dry" gas is consumer-grade natural gas. Basically, it is natural gas that that has been processed to remove hydrocarbon liquids and other impurities so that it has uniform properties that make it transportable and useable by all consumers. Dry natural gas production equals marketed production less extraction loss.

Figure 1. Henry Hub price forecasts (Actuals, NYMEX, AESC 2020, and AESC 2018)



As shown in Figure 1, Henry Hub natural gas prices average 34 percent lower in AESC 2021 compared to AESC 2018 over the 2021–2035 period. In general, forecasts of Henry Hub prices have continually declined over the past decade for several reasons.

1. Productivity in shale drilling has been increasing steadily. Average productivity (new well gas production per rig) as reported by EIA was about 1,284 Mcf at the beginning of 2014. Productivity was 3,570 Mcf in EIA's January 2018 report and 6,906 Mcf in the latest (2021) report.[19] This trend implies decreasing costs per unit of production, although AEO continues to assume that new supply will not be as productive as in the past, thus requiring higher prices to induce drilling.

2. A growing portion of gas production has been coming from oil wells (e.g., "associated natural gas"). For oil producers, drilling decisions are based on crude oil prices and any natural gas sold is considered a byproduct. Depending on gas pipeline availability and flaring regulations, this gas will be produced at any price as long as crude oil economics are positive. As new tranches of associated gas are marketed, they often displace existing gas production pressuring gas prices.

3. Realtime indicators are difficult to ignore. Since 2010, average gas prices have been on a downward trend—weekly, monthly, and annually. For example, the average Henry Hub spot price for two years prior to the initial 2015 AESC forecast was about $4.59 per MMBtu (in 2021 dollars), while for the 2018 report it was $2.96 per MMBtu. For the two years prior to AESC 2021 (2019 and 2020), the average price was $2.33 per MMBtu. The

[19] U.S. EIA. 2021. "Drilling and Productivity Report," January 19.

past decade has seen price spikes due to abnormal weather or short-term storage deficits, but projecting a sustained upward price surge is difficult to justify.

4. The COVID-19 pandemic initially exacerbated a bearish price cycle. The average Henry Hub spot price for the 12-months ending October 2020 was $2.00 per MMBtu, the lowest in over two decades. This price signal has led to near-record short-term production declines the second and third quarters of 2020. The market has recognized this, with NYMEX Henry Hub futures averaging closer to $3.00 per MMBtu beginning in the fourth quarter.

Natural gas prices at other upstream supply points

Although Henry Hub is the U.S. natural gas price benchmark, prices vary greatly across the nation. Conditions such as local production, pipeline capacities, storage availability, and demand variability are some of the many factors that cause this variation. Over the past few decades, most supply and consuming regions developed gas hubs, which are liquid pricing points where gas is bought and sold for immediate or future delivery. There are many hubs in the Northeast, but the critical question is which ones determine New England's natural gas prices?

Without indigenous production, New England continues to acquire gas from outside the region via:

1. Six pipeline systems including Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) from the south; Iroquois Gas Transmission (IGTS) from the west through New York State; and Maritimes & Northeast Pipeline (MNP) along with Portland Natural Gas Transmission (PNGTS) from Canada via TransCanada Pipeline (TCPL). See below for a more detailed description of the six pipeline systems.

2. Two LNG import terminals in the Boston area including Excelerate Energy's Northeast Gateway Deepwater Port and Exelon Generation's Everett terminal. There is also the Canaport LNG import terminal in New Brunswick, from which regasified LNG can be piped down MNP into New England.

Pipeline shippers purchase natural gas at various supply or market hubs. This natural gas may be sourced from the U.S. Gulf Coast, Midwest, Appalachia, and both Eastern and Western Canada; however, production in the Marcellus/Utica has outstripped natural gas consumption in the Northeast. As a result, the physical source of New England pipeline gas is being increasingly supplied from this nearby basin even if shippers are notionally purchasing gas from distant supply basins (Gulf Coast, Western Canada, Permian Basin, etc.).[20] Thus the price at hubs that source Marcellus/Utica gas is increasingly relevant to New England.

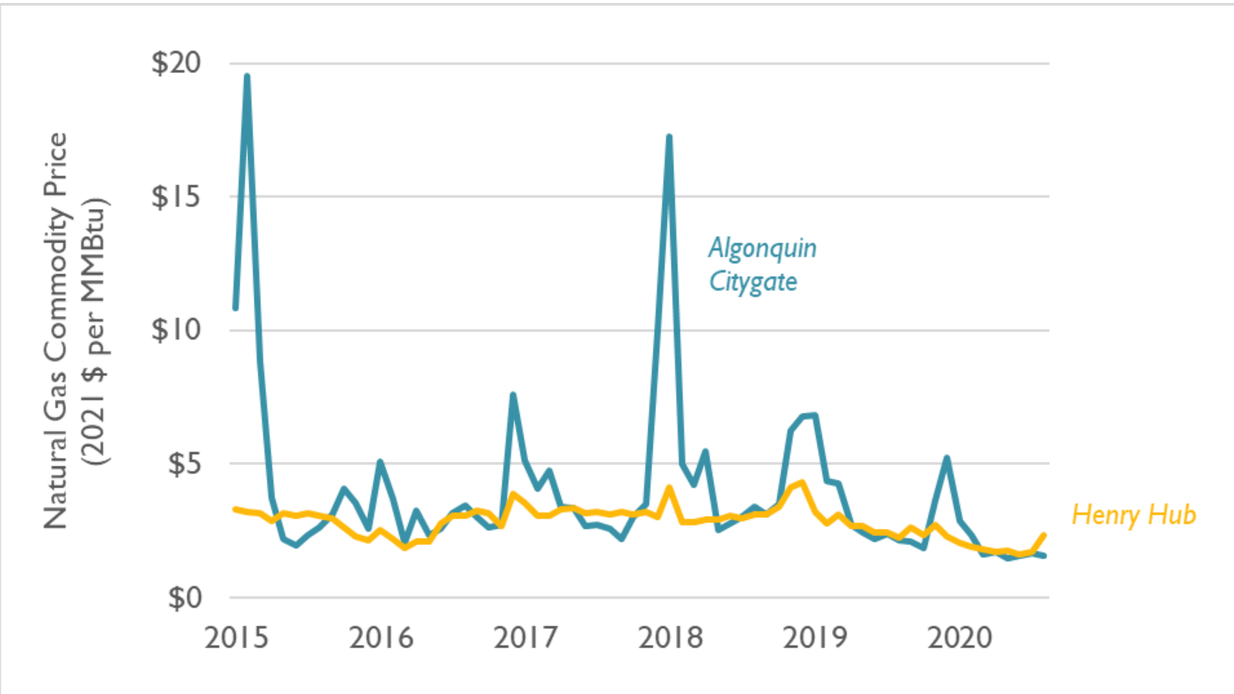
Although sourced from various upstream supply basins, a significant volume of New England gas is priced at the Algonquin Citygate Hub. AGT basis futures are traded on the Intercontinental Exchange

[20] Since natural gas is fungible, interstate pipelines can displace gas anywhere it enters or leaves the system.

(ICE) and there is a market up to 48 months out.[21] AGT spot prices are also quoted in several publications[22] and on the EIA website.[23] For 2024 and later years, to calculate the future monthly variation in prices for Henry Hub, Algonquin Citygate, and other and hubs upstream of New England, we average two years of projected monthly data (based on NYMEX) for the period 2022–2023.[24] For Henry Hub, the "shape" of this monthly variation is applied to the annual data from AEO 2021. For Algonquin Citygate and other hubs, we simply add the average monthly basis to the Henry Hub value.

We have also analyzed historical monthly basis data for these pricing points, allowing us to apply the seasonality in monthly prices to our longer-term projections. See Figure 2 for a historical comparison of gas prices at Algonquin Citygate and Henry Hub.

Figure 2. Historical comparison of natural gas prices at Algonquin Citygate Hub and Henry Hub



[21] Intercontinental Exchange (ICE). Last accessed March 9, 2021. "Algonquin Citygates Basis Future." *theICE.com*. Available at https://www.theice.com/products/6590124/Algonquin-Citygates-Basis-Future.

[22] Natural Gas Intelligence (NGI). Last accessed March 9, 2021. "Algonquin Citygate Daily Natural Gas Price Snapshot." *NaturalGasIntel.com*. Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/.

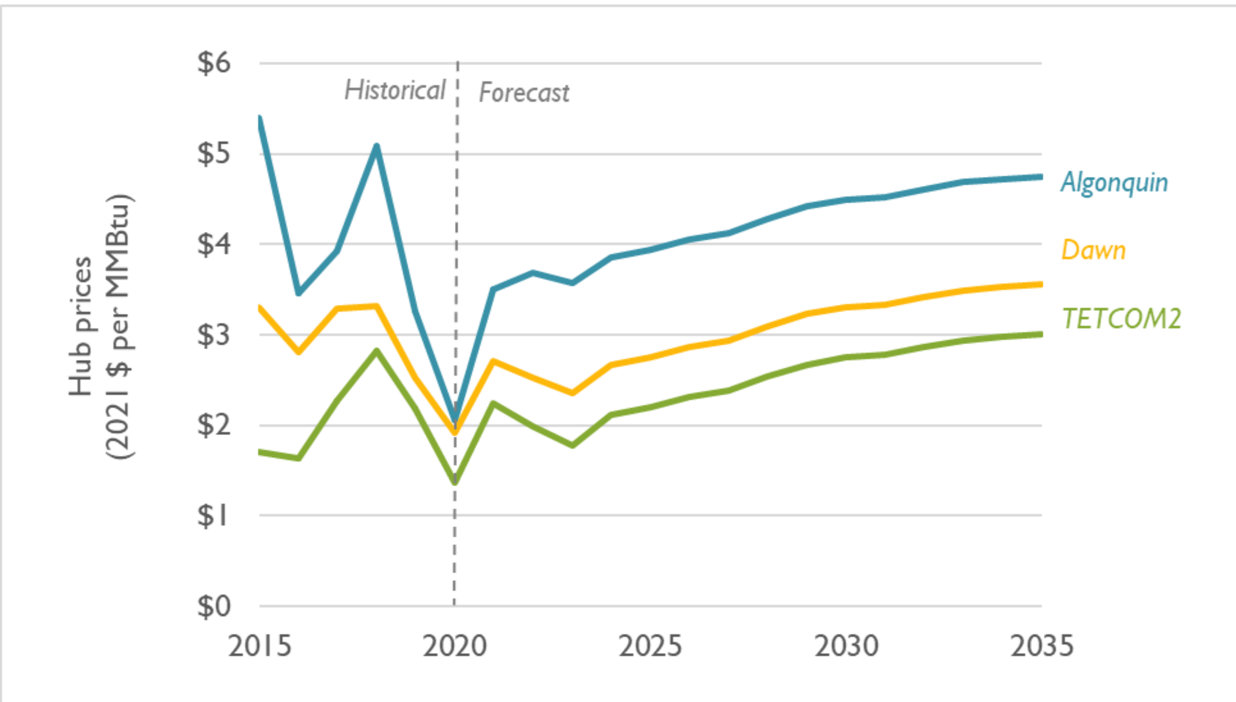
[23] U.S. EIA. Last accessed March 9, 2021. "Daily Prices." *Today in Energy*. Available at https://www.eia.gov/todayinenergy/prices.php.

[24] The term upstream generally refers to hubs and other points closer to the source of gas production.

In AESC 2021, we use the Texas Eastern Zone M-2 (TETCO M2) price, which is more representative of the actual prices paid by New England LDCs.[25] To cover the major gas supply sources, we model monthly prices at the Dawn Ontario Hub and TETCO M2 Hub using a similar methodology as our projection for the Algonquin Citygate basis (see Figure 3). The projected monthly basis values for these hubs are assumed to remain constant in real dollar terms over the modeling period.

While often correlated, natural gas prices at each hub will vary, depending on supply, demand and pipeline capacity, transport costs, and other conditions. There are trading platforms for these hubs: NYMEX trades (TETCO M2), and Natural Gas Intelligence (NGI) publishes prices for the Dawn Hub.[26] In most cases there is both a spot and a futures market of varying lengths at these hubs. Also note that these price forecasts implicitly assume no new large-scale pipeline expansion projects, other than ones under construction slated over the next year.[27] We believe the futures prices used in this analysis embed an unbiased estimate of the market's expected seasonal demand-supply pressures in the near term.

Figure 3. Historical and projected prices for AGT Hub, Dawn Hub, and TETCO M2 Hub



[25] In AESC 2018, we used the Dominion South Point (hub) index to measure gas prices in the Marcellus shale producing areas in and about Pennsylvania.

[26] NGI. Last accessed March 9, 2021. "Dawn Forward Fixed Natural Gas Price Snapshot." *NaturalGasIntel.com*. Available at http://www.naturalgasintel.com/data/data_products/forward-contracts?location_id=MCWDAWN&region_id=midwest.

[27] See Algonquin's "Atlantic Bridge Project" CP16-9.

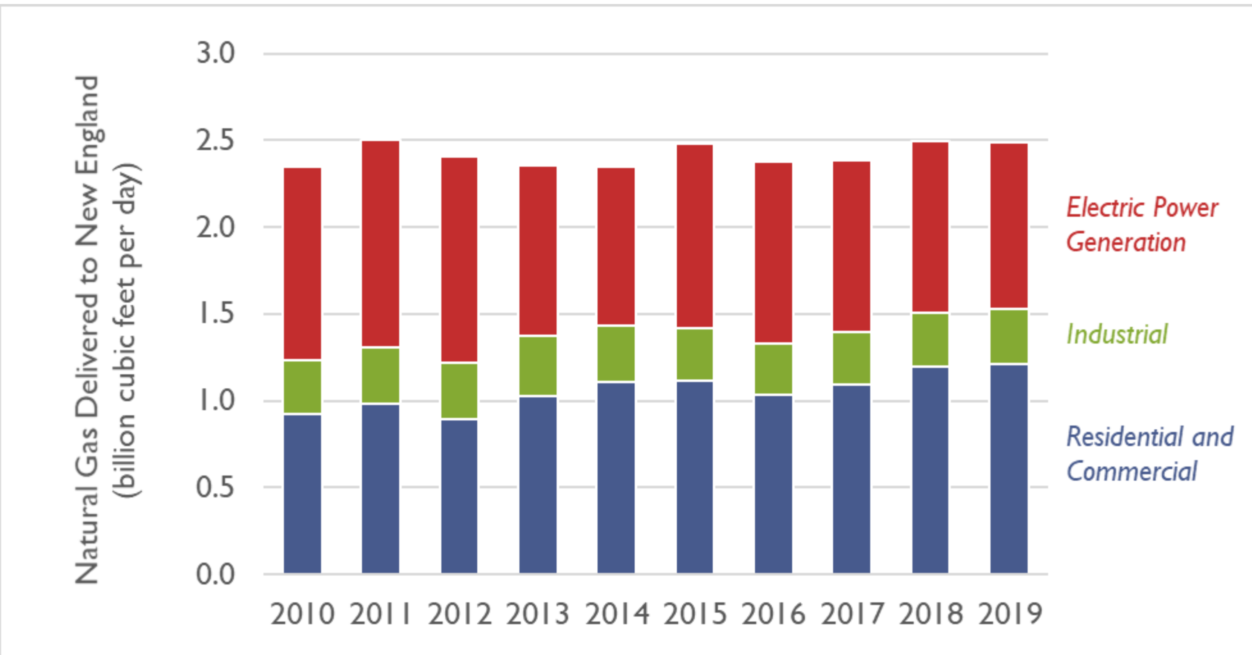
2.3. New England natural gas market

In addition to the commodity costs discussed above, natural gas avoided costs include the costs of transmission, storage, and peaking resources needed to make gas available where and when it is consumed. This section addresses the gas supply resource costs that would be avoided by reducing gas use and describes our methodology for calculating the avoided natural gas costs by end-use.

Natural gas consumption

Figure 4 shows the natural gas delivered to end-users in the six New England states for the years 2010 through 2019. Growth in residential and commercial consumption has been largely offset by lower gas use for electricity generation.

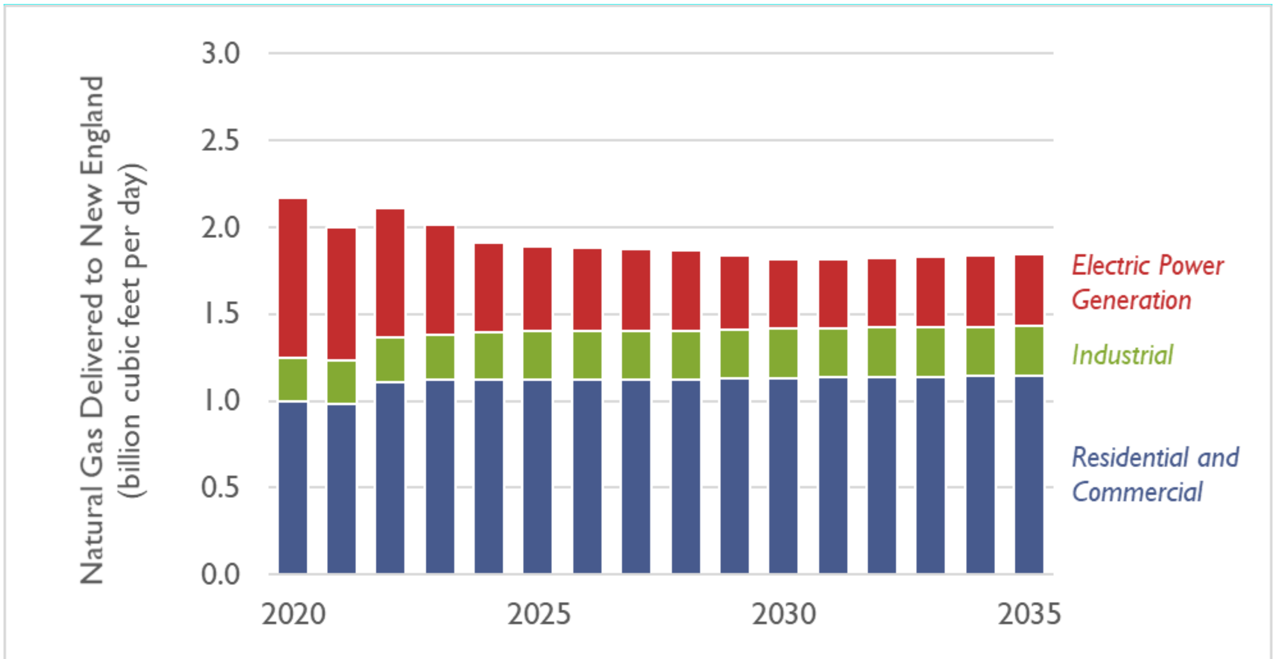
Figure 4. Historical natural gas deliveries in New England



Source: Energy Information Administration (EIA). Available at https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm.

Going forward, the AEO 2021 Reference case forecast for New England shows a small near-term increase in consumption in the residential, commercial, and industrial sectors, then a flattening of gas consumption from the mid-2020s through the mid-2030s (see Figure 5). Meanwhile, EIA projects gas consumption in the electric power sector to be halved by 2025, then remain at a relatively consistent level through the mid-2030s.

Figure 5. AEO 2021 natural gas consumption forecast for New England



Source: Energy Information Administration (EIA). Available at https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_2.1.xlsx.

Recent New England LDC forecasts show annual growth in customer requirements ranging from 0.2 percent to 2.3 percent per year (see Table 1). For the 13 LDC forecasts shown, the weighted average increase in requirements over a five-year period is just under 2 percent per year.[28]

There are several reasons why the LDC forecasts would be different from the EIA forecast:

- The LDC forecasts are "planning load" forecasts, not forecasts of total consumption. Planning load customers are sales customers that buy gas from the LDC, and transportation-only customers that buy gas from marketers that receive upstream capacity resources from the LDC under retail choice programs. "Capacity exempt" transportation customers that do not use LDC supply resources are excluded.
- LDC planning load excludes most gas used for electricity generation. Gas-fired power plants in New England typically receive gas supplies directly from an interstate pipeline or transport gas on an LDC under a special contract that makes them capacity-exempt.
- Some LDCs adjust their forecasts to include potential migration of existing capacity-exempt transportation customers to sales service or capacity-assigned transportation service. Shifting gas use by existing capacity-exempt transportation customers into

[28] Growth rates weighted by the annual planning load forecasts for 2020-21.

planning load causes the planning load growth rate to be higher than the actual growth in total consumption.

- Recent LDC forecasts reflect lower 2020 and 2021 gas use caused by COVID-19; they assume that consumption will bounce back later in the forecast period. This would cause the average annual growth rates for forecasts with a 2020 start date to be somewhat higher than pre-COVID forecasts, all else being equal.

- Finally, there are questions about the extent to which the econometric forecasts produced by New England LDCs reflect the future impacts of state initiatives to reduce GHG emissions. The Massachusetts Attorney General has suggested that LDCs should be required to submit forecasts for periods longer than five years in order to address the expected transition away from natural gas as a heating fuel.[29]

Table 1. New England LDC natural gas requirements forecasts

Utility	CAGR (%)	2020-2021 forecast (MMcf)		Forecast period	Case or Docket Number
		Annual	*Design Day*		
National Grid (MA)	2.3	136,633	1,425	2020 to 2025	MA DPU 20-132
Eversource Gas	0.8	48,660	522	2019 to 2024	MA DPU 19-135
NSTAR Gas	1.5	47,907	537	2019 to 2024	MA DPU 20-76
Liberty (MA)	1.0	6,452	77	2020 to 2025	MA DPU20-92
Berkshire Gas	0.5	6,472	66	2020 to 2025	MA DPU 20-139
Fitchburg Gas	0.2	2,314	23	2020 to 2025	MA DPU 21-10
CT Natural Gas	1.6	36,124	355	2020 to 2025	CT PURA 1820-10-02
Southern CT	1.2	33,167	325	2020 to 2025	CT PURA 1820-10-02
Yankee Gas	2.2	56,256	487	2020 to 2025	CT PURA 1820-10-02
National Grid (RI)	1.8	36,152	389	2019 to 2025	RI PUC 5043
EnergyNorth	2.3	15,650	165	2017 to 2022	NH PUC DG 17-152
Northern Utilities	1.5	15,628	143	2019 to 2024	NH PUC DG 19-126
Vermont Gas	0.2	7,162	72	2020 to 2025	VT PUC 20-1520
Total		**448,557**	**4,585**		

Gas supply resources

The natural gas consumed in New England comes from the natural gas pipelines that transport gas from producing areas in the United States and Canada, and import terminals in Massachusetts and New Brunswick that receive LNG by ship. A small, but growing amount of natural gas is transported into New England by truck as either LNG or compressed natural gas (CNG).

Gas transmission pipelines

Six major natural gas pipeline systems deliver gas to New England markets (see Figure 6).

Tennessee Gas Pipeline (TGP): Two branches of the TGP mainline deliver gas into New England. The “200 Line” enters Massachusetts from upstate New York and extends into the Boston area. The “300

[29] Massachusetts Office of the Attorney General’s June 4, 2020 petition in Docket D.P.U. 20-80, pp. 12-13.

Line" enters southwestern Connecticut and connects to the 200 Line at Agawam, MA. Lateral pipelines transport gas into Rhode Island and New Hampshire.

Algonquin Gas Transmission (AGT): AGT is a regional pipeline that extends from central New Jersey to Boston. AGT receives gas from TGP at Mahwah, NJ and from Millennium Pipeline at Ramapo, NY. AGT delivers gas in Connecticut, Rhode Island, and Massachusetts. The AGT system also includes a 25-mile undersea pipeline (the "HubLine") that extends from Weymouth, MA to an interconnection with Maritimes & Northeast Pipeline (MNP) in Salem, MA.

Iroquois Gas Transmission System (IGTS): IGTS connects with the TransCanada PipeLines system (TCPL) at Waddington, NY. IGTS crosses the southwestern corner of Connecticut before terminating in Long Island and New York City. IGTS connects with TGP at Wright, NY, and with AGT at Brookfield, CT. Direct deliveries from IGTS into the New England are constrained by the capacity of Connecticut LDCs and power generators to receive gas at IGTS meters and competition from downstream markets in New York.

Portland Natural Gas Transmission System (PNGTS): PNGTS receives natural gas from TCPL at the New Hampshire-Quebec border. TCPL delivers this gas using capacity that it holds on TransCanada's (Trans Quebec and Maritimes) TQM pipeline. PNGTS connects with MNP at Westbrook, ME and delivers gas into TGP at Dracut, MA.

Maritimes & Northeast Pipeline (MNP): MNP was originally built to transport gas from offshore Nova Scotia to Canadian and U.S. markets.[30] The U.S. portion of the MNP system extends from the Maine-New Brunswick border to northeastern Massachusetts. MNP also receives gas from the Brunswick Pipeline, which is the outlet for the Canaport LNG terminal at St. John in New Brunswick. MNP connects with PNGTS at Westbrook, ME, with TGP at Dracut, MA, and with AGT at Salem, MA.

TransCanada PipeLines (TCPL): The TCPL mainline extends from Alberta to Quebec. TCPL receives gas in Alberta and from Enbridge Gas at the Parkway interconnect in southwestern Ontario.[31] TCPL connects directly to Vermont Gas System (VGS), and delivers gas into IGTS and PNGTS.

Liquefied natural gas (LNG) import terminals

Imported LNG is received at three terminals located in Massachusetts and New Brunswick.

Distrigas of Massachusetts: The Distrigas LNG terminal, located in Everett, MA, delivers gas to TGP, AGT, National Grid, and the Mystic Generating plant. Distrigas also delivers LNG into trucks that supply peaking gas facilities throughout the region.[32]

[30] Natural gas production in Nova Scotia ended in 2018.

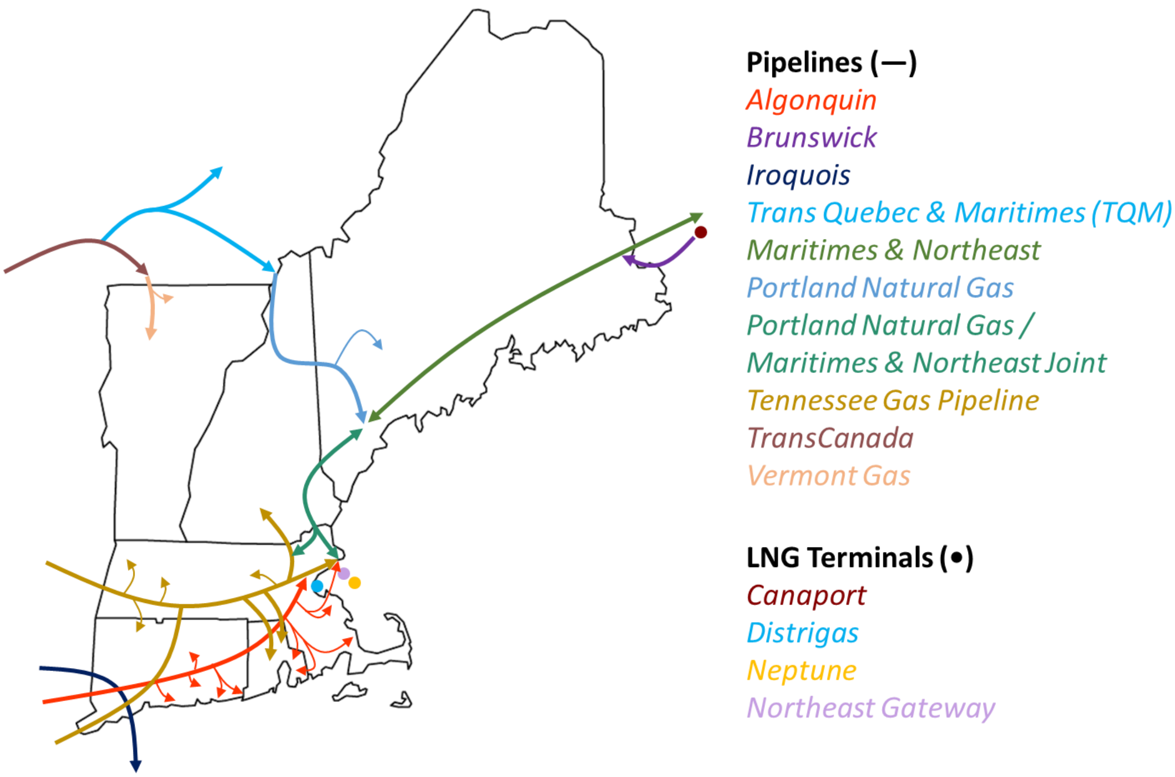
[31] Enbridge Gas (formerly Union Gas Limited) operates the Dawn Hub.

[32] The Distrigas terminal is owned by an Exelon Corporation subsidiary.

Northeast Gateway: Northeast Gateway is an offshore LNG receiving facility that connects to the AGT HubLine. Northeast Gateway began operating in 2008, but it has received only a few winter-season shipments in recent years.[33]

Canaport LNG: The Canaport LNG terminal has close to 10 Bcf of storage capacity and can send out approximately 1Bcfd. Repsol Energy North America, the Canaport operator, has a long-term contract for firm transportation service on MNP and uses this capacity to deliver gas at Dracut and Salem, and to markets in Maine.

Figure 6. Natural gas pipeline infrastructure in New England and nearby regions



Source: Synapse Energy Economics, 2021.

Natural gas delivery capacity

Total gas delivery capacity into New England increased by roughly 4 percent from 2018 to 2021 and is expected grow by another 1.5 percent from 2021 to 2024 (see Table 2). For AGT and TGP, we show the estimated west-to-east capacity to deliver gas into New England from New York. The IGTS capacity is an estimate of the amount of gas that can be received in Connecticut, and it excludes capacity used to transport gas through New England to downstream markets in New York. The “TCPL Direct” quantities are the receipt capacities of VGS and PNGTS at the U.S.-Canada border. The “LNG Dependent” quantities

[33] A second offshore LNG receiving terminal, Neptune, was built about the same time, but is now inactive.

show the certificated end-to-end capacity of the MNP pipeline and the estimated sendout capacity of the Distrigas facility, based on the take-away capacity of the interconnected pipelines. Note that the effective delivery capacity for MNP and Distrigas at any point in time is likely to be lower than shown in the table, since it will depend on the availability of LNG supply.

The supply of natural gas to the New England market is also reduced by exports to New Brunswick and Nova Scotia. EIA reports that 0.25 Bcfd of natural gas flowed into New Brunswick from Maine in 2019.[34] Canadian LDCs and end-users have contracted for pipeline capacity in the Atlantic Bridge, Portland XPress, and Westbrook XPress expansion projects.

Table 2. Historical and Projected Natural gas delivery capacity into New England (Bcfd)

	JAN 2018	JAN 2021	JAN 2024
AGT	1.82	1.91	1.91
TGP	1.39	1.39	1.42
IGTS	0.26	0.26	0.26
West-to-East	**3.47**	**3.56**	**3.59**
PNGTS	0.21	0.32	0.40
VGS	0.07	0.08	0.08
TCPL Direct	**0.28**	**0.40**	**0.48**
MNP	0.83	0.83	0.83
Distrigas	0.70	0.70	0.70
LNG Dependent	**1.53**	**1.53**	**1.53**
TOTAL	**5.28**	**5.49**	**5.60**

Table 3 provides details on recent and planned pipeline expansion projects that affect gas delivery capacity into the New England market.

[34] U.S. EIA. Last accessed March 9, 2021. "U.S. Natural Gas Exports and Re-Exports by Point of Exit." *eia.gov.* Available at https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm.

Table 3. Recent and planned New England pipeline expansions

Pipeline	Project	Capacity (Bcfd)	Description	Status
AGT	AIM	0.342	Expand from Ramapo, NY to New England citygates	Completed early 2017
TGP	CT Expansion	0.072	Expand from Wright, NY to CT citygates	Completed in 2017
AGT	Atlantic Bridge	0.133	Expand from Ramapo, NY to Salem, MA	Added 0.040 Bcfd in 2017, 0.093 Bcfd in 2019
TGP	261 Upgrades	0.027	Upgrade compression and expand Agawam, MA lateral	Lateral completed 2020. Compression planned for 2021
PNGTS	Portland XPress	0.064	Expand from Canadian border to Dracut, MA	Completed 2018, 2019, and 2020
PNGTS	Westbrook XPress	0.123	Expand from Canadian border to Westbrook, MA and Dracut	Added 0.043 Bcfd in 2020. Phases II and III in 2021 and 2022.
Total	**-**	**0.761**	**-**	**-**

Peaking facilities

Most New England LDCs operate on-system peaking facilities that inject either vaporized LNG or propane into the distribution system during periods of high gas demand (see Table 4). The total design-day production capacity for these facilities is approximately 1.5 Bcfd. Many of the LDC peaking facilities have on-site storage, but others are satellite facilities that require mid-winter refill by truck.

Table 4. New England LDC peaking facilities

Gas Utility	Type	Number of facilities	Aggregate Delivery Capacity (Bcf/day)	Aggregate Storage Capacity (Bcf)
National Grid (MA)	LNG	7	0.508	4.934
Eversource Gas	LNG	4	0.112	1.688
NSTAR Gas	LNG	2	0.210	3.650
Liberty (MA)	LNG	1	0.018	0.165
Berkshire Gas	LNG	1	0.003	0.010
Fitchburg Gas	LNG	1	0.003	0.003
CT Natural Gas	LNG	1	0.105	1.142
Southern CT	LNG	1	0.082	1.142
Yankee Gas	LNG	1	0.105	1.200
National Grid (RI)	LNG	2	0.174	2.462
EnergyNorth	LNG	3	0.013	0.013
Northern Utilities	LNG	1	0.006	0.012
Eversource Gas	Propane	4	0.058	0.137
Berkshire Gas	Propane	3	0.008	0.053
Fitchburg Gas	Propane	1	0.011	0.030
EnergyNorth	Propane	3	0.035	0.108
Vermont Gas	Propane	1	0.008	0.015
Total			**1.459**	**16.764**

Compressed natural gas

Several companies operate compression facilities in New England that fill large-capacity truck trailers with CNG.[35] The primary customers for trucked CNG are industrial and large commercial end-users that would not otherwise have access to natural gas. LDCs can also use CNG as a winter peaking resource, or as a source of gas supply for isolated market areas.[36]

CNG can expand the natural gas market by allowing large end-users to switch to gas from another fuel. However, the impact that CNG will have on the New England gas market will depend on where the CNG is produced. When CNG is produced locally, it can increase the need for pipeline capacity to deliver gas into the New England region. CNG facilities that are connected to LDCs (iNATGAS, for example, is a firm sales customer of EnergyNorth) can also increase the requirement for gas supply resources and distribution capacity. Alternatively, CNG that is transported into New England from compression facilities outside the region can be a source of gas supply that reduces the need for pipeline capacity and other sources of supply. For example, XNG has modified its Eliot, ME facility to also receive CNG and inject gas into the M&N/PNGTS joint facilities pipeline.

Renewable natural gas

RNG is pipeline-quality gas that is extracted from landfills, or produced from waste material using anaerobic digesters. Substituting RNG for natural gas is a means of reducing GHG emissions. See Section 8.1. *Non-embedded GHG costs* for a larger discussion on RNG costs and potentials.

Vermont Gas and Summit Natural Gas of Maine (SNGME) have implemented voluntary sales programs under which customers can choose to have a portion of their gas consumption backed by RNG.[37] Both programs currently use RNG that is produced outside of New England.[38]

Several projects are proposed or in development that would supply RNG to New England LDCs:

- An anaerobic digester facility under construction at a dairy farm in Salisbury, VT is expected to deliver 180,000 Mcf per year to Vermont Gas.[39]

[35] NG Advantage has facilities in Milton, VT and Pembroke, NH. Xpress Natural Gas (XNG) has facilities in Eliot, ME and Baileyville, ME. Innovative Natural Gas (iNATGAS) has facilities in Worcester, MA and Concord, NH.

[36] For example, XNG supplies CNG to EnergyNorth's Keene, NH distribution system.

[37] Summit Natural Gas Maine. Last accessed March 10, 2021. "A Program to help Build a Sustainable Energy Future." *summitnaturalgas.com.* Available at https://www.summitnaturalgasmaine.com/RenewableNaturalGas.

[38] RNG for the Vermont Gas program comes from a landfill in Quebec and a wastewater treatment plant in Iowa. SNGME is buying RNG attributes from a landfill in Oklahoma.

[39] Vanguard Renewables. Last accessed March 10,2021. "Goodrich Farm." *Vanguardrenewables.com.* Available at https://vanguardrenewables.com/portfolio-items/goodrich-farm-salisbury-vt/.

- In August 2020 SNGME received Maine PUC approval to buy up to 146,000 Mcf of RNG per year from Peaks Renewables, Inc., which is developing an anaerobic digester facility at a dairy farm in Clinton, ME.[40]
- In 2018, EnergyNorth asked the New Hampshire PUC to approve an agreement to buy RNG that would be produced at a landfill in Bethlehem, NH. Because of the location of the landfill, the RNG would be compressed, and delivered to EnergyNorth by truck.[41]

2.4. Avoided natural gas cost methodology

AESC 2021 uses the same avoided cost methodology used for AESC 2018, as described below.

Avoidable gas supply costs

Gas supply resources are often categorized as baseload, intermediate, or peaking. Baseload resources, such as pipeline capacity that extends from outside the local market area, tend to have a relatively high fixed cost but a lower variable cost. This type of resource is best suited to supplying high-load-factor uses, where gas is consumed at a relatively constant rate throughout the year. Peaking resources, such as on-system LNG, typically have lower fixed costs but higher variable costs. These types of resources are a better fit for gas requirements that occur on a limited number of days per year. Intermediate resources, such as short-haul pipeline capacity or a winter season gas storage service, are often used to support winter heating requirements.

The avoided natural gas supply cost for an LDC will depend on the characteristics of the gas requirement reduced, and the cost of the marginal resource that would be used to supply each type of load. For example, if the load reduction is limited to commercial and industrial non-heating customers, the avoided cost will usually be the marginal cost of a baseload gas supply resource. For a change in residential heating load, the avoided cost is likely to involve a combination of resources, since the variable gas usage pattern of residential heating customers utilizes a wider range of gas supply resources.

Estimates of the gas supply costs that can be avoided by energy efficiency program savings are calculated for each state, by region, for each of the following end-use categories:

1. Electric generation
2. Commercial and industrial non-heating
3. Commercial and industrial heating

[40] ME PUC Docket No. 2020-00089. SNGME will buy the gas produced by the facility, but not the RNG Attributes. Peaks Renewables is an affiliate of SNGME.

[41] NH PUC Docket No. DG 18-140. EnergyNorth withdrew its application to the NH PUC in February 2020, but did not state that the project has been abandoned.

4. Residential heating
5. Residential water heating
6. Residential non-heating
7. All commercial and industrial
8. All residential
9. All retail end-uses

We provide avoided natural gas values by costing period, allowing readers of AESC to develop more specific avoided costs for other measures not listed above.

Our natural gas avoided cost methodology has three steps.

Step 1 is to identify the marginal gas supply resource for each load type (i.e., baseload, intermediate, or peaking). For electric generation, we assume the applicable natural gas cost is the New England wholesale market price. For the retail end-use categories, we examine the existing and potential gas supply resources that would potentially be the marginal source of supply.

For each resource that could potentially be increased or decreased in response to a change in gas requirements, we then estimate the total delivered cost of the resource for each costing period, expressed in $/MMBtu/year. We exclude unavoidable costs. The marginal resource for each costing period is assumed to be the resource with the lowest delivered cost over the forecast horizon.

Step 2 is to determine the percentage of load for each end-use type that corresponds to each costing period. For all states except Vermont, we use the same six costing periods used in AESC 2018 as detailed below:[42]

1. Highest 10 days
2. Highest 30 days
3. Highest 90 days
4. Winter (November-March)
5. Winter/Shoulder (All months except June-August)
6. Annual Baseload

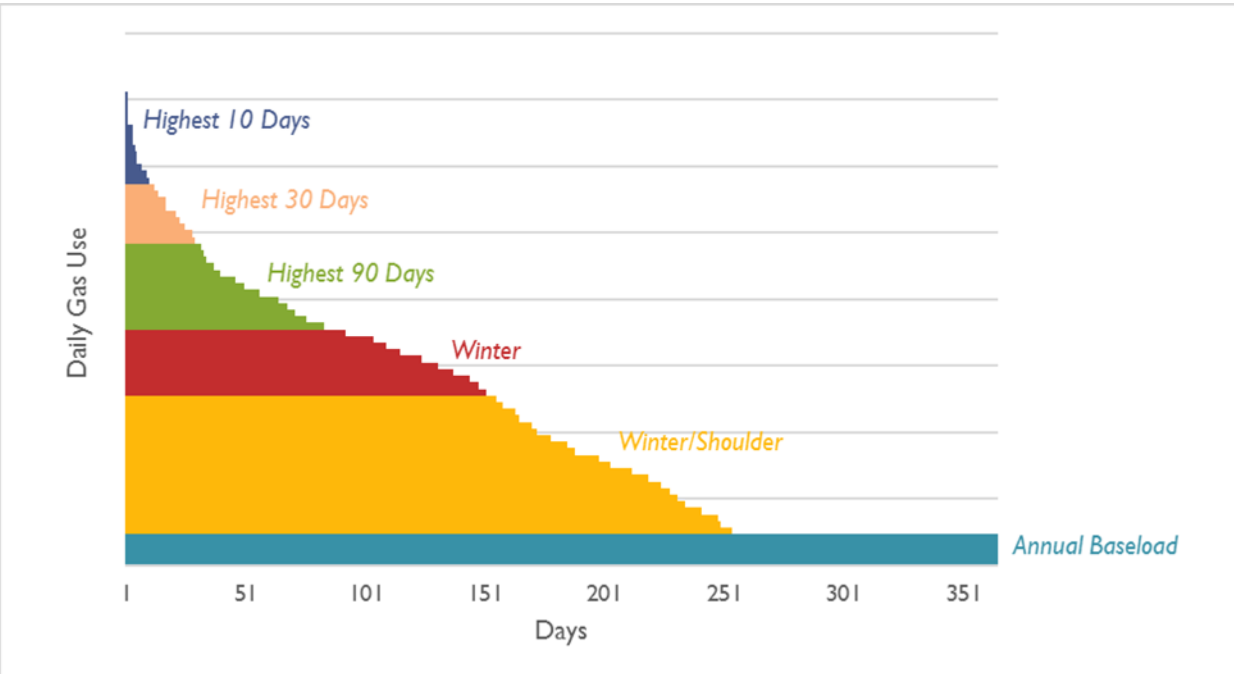
These costing periods generally correspond to the different types of gas supply resources that New England LDCs acquire to meet projected end-use requirements. Requirements that extend through the

[42] For Vermont, natural gas avoided costs are estimated for four time-of-use costing periods: peak day, next highest nine days, remaining winter (141 days), and summer/shoulder (214 days).

Annual Baseload and Winter/Shoulder periods are typically met with pipeline capacity from outside the region. Winter period requirements, and gas requirements that must be met at least 90 days per year, are often supplied using pipeline capacity from New England supply points or contracts for delivered gas. The shorter-duration requirements are typically supplied using on-system peaking resources and contracts for delivered peaking supplies.

The load shares for each end-use type are calculated from a load curve that combines a representative gas use equation (base use per day and use per heating degree day, or HDD) and a representative HDD distribution. This is illustrated by Figure 7, which shows a sample load curve for the Commercial and Industrial Heating end-use category. The load share for the Winter costing period, for example, is based on the amount of gas use that occurs at least 151 days per year, minus the gas use that only occurs on the highest 90 days. A resource that supplies planning load requirements during the Winter costing period would be used an average of 120 days per year, which corresponds to an annual load factor of 33 percent.

Figure 7. Illustrative commercial and industrial heating load shape



Step 3 is to multiply the marginal resource cost for each costing period by the corresponding load percentages. Summing the results over all costing periods gives the total annual avoided cost for each end-use. This calculation is repeated for each end-use type, for each year of the forecast period as illustrated in Table 5.

Table 5. Illustrative avoided cost calculation

Costing Period	Marginal Resource Cost ($/MMBtu)	Share of Annual Gas Use	Weighted Average ($/MMBtu)
	(A)	(B)	(A) x (B)
Annual	$4.00	-	-
Winter/Shoulder	$5.00	60%	$3.00
Winter	$6.00	25%	$1.50
Highest 90 Days	$8.50	10%	$0.85
Highest 30 Days	$15.00	4%	$0.60
Highest 10 days	$30.00	1%	$0.30
ILLUSTRATIVE AVOIDED COST FOR THIS END-USE TYPE →			**$6.25**

Assumptions and data sources

The following sections contain information about the assumptions and data sources used to construct avoided natural gas costs for New England.

New England regions

Natural gas avoided costs are estimated for three regions: (1) southern New England (Connecticut, Rhode Island, and Massachusetts); (2) northern New England (New Hampshire, Maine); and (3) Vermont.

Load shares

The load shares used for the avoided cost calculation are based on a representative HDD distribution, as well as base use per day and use per HDD factors by end-use category that were provided by study sponsors.[43] The same load share factors are used for all regions. The proportions of baseload and temperature-sensitive gas use for the five end-use categories are shown in Table 6.

Table 6. Base use and heating factors by end-use

End-use	Base use (Percent)	Temperature sensitive (Percent)
Residential Heating	-	100%
Residential Water Heating	69%	31%
Residential Non-Heating	100%	-
Commercial & Industrial Heating	21%	79%
Commercial & Industrial Non-Heating	68%	32%

Natural gas transmission costs

For AESC 2021, transmission costs are measured using the rates that New England LDCs pay to upstream pipelines for firm transportation services. These rates include a fixed reservation charge that is applied

[43] This assumes that the daily temperature distributions for the New England states are similar, even though the total annual HDDs are different in each state.

to the daily contract quantity and a variable charge that is applied to the quantity of gas transported. Pipelines also retain a percentage of the gas transported for compressor fuel and for "lost and unaccounted for" gas (see page 46).

Because the cost to build new pipeline facilities is generally higher than the costs of the depreciated assets that are used to set the pipelines' standard cost of service rates, interstate pipelines usually charge higher "incremental" rates for new services to avoid subsidization by the pipeline's other shippers. Shippers that participate in pipeline expansion projects often enter into negotiated rate agreements that set the transportation rate over the initial contract term.

The avoided cost estimates in AESC 2021 assume that LDCs can adjust the amount of transmission service they have under contract when customer requirements change. In a market such as New England, where natural gas use by LDC planning load customers is projected to increase, energy efficiency measures that reduce gas use should cause future pipeline expansions to be smaller.[44] For pipelines that price new capacity using incremental rates, the avoided transmission cost is the actual or proposed rate for the applicable pipeline's most current mainline expansion project. For the Canadian pipelines, which do not charge incremental rates for new capacity, the avoided cost is measured by the tariff rate.

Gas resource options for AESC 2021

Based on our review of New England LDC forecasts and resource plans, and other public material filed with state regulators, we assume that LDCs will obtain additional gas supplies using a combination of the representative gas resource options described here:

<u>Resource 1: Dawn Hub supply via TCPL</u>

This supply option includes Enbridge Gas transportation service from the Dawn Hub to TCPL, TCPL service to PNGTS, and service on PNGTS to Dracut. LDCs in southern New England also contract for TGP service to move gas Dracut to their city gates.

Vermont Gas currently obtains all pipeline-delivered gas supplies from the Dawn Hub and other Ontario points through its direct connection to TCPL. We assume that this will continue.

The costs for this option are based on Enbridge Gas and TCPL 2021 transportation rates and projected PNGTS expansion costs (see Table 7). Pipeline costs include the fixed reservation charge, shown as an average cost per MMBtu, the variable transportation charge, and the percentage of the natural gas transported that the pipeline retains for compressor fuel and unaccounted-for gas (see page 46). The gas commodity cost is the projected Dawn Hub price.

[44] See Table 3 for a list of recent and planned pipeline expansion projects.

Table 7. Transmission costs for the Dawn Hub capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Enbridge Gas	Dawn Hub	Parkway	0.099	0.0	0.8%
TCPL	Parkway	VGS	0.446	0.0	0.9%
TCPL	Parkway	PNGTS	0.569	0.0	1.5%
PNGTS	TCPL	Dracut	0.854	0.0	0.7%
TGP	Dracut	TGP Zone 6	0.137	0.029	0.1%

Resource 2: Marcellus supply via AGT

This pipeline capacity path extends from the Marcellus shale gas producing areas in Western Pennsylvania to New England markets. The costs for this path include the Millennium Pipeline transportation costs from the Marcellus area to Ramapo, NY, and the incremental rates charged for Atlantic Bridge expansion project for transportation from Ramapo to New England. For northern New England, there are additional transportation costs on MNP to deliver gas from the end of the AGT system to markets in New Hampshire and Maine (see Table 8). The TETCO M2 index is used as the representative price for Marcellus-area gas supply received by Millennium Pipeline.

Table 8. Transmission costs for the Marcellus capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Millennium	Marcellus	Ramapo	0.583	0.002	1.4%
AGT	Ramapo	Salem	1.805	0.0	2.6%
MNP	Salem	NH or ME	0.522	0.0	0.9%

Resource 3: Dracut supply via TGP (southern New England)

Gas is purchased at Dracut, where TGP connects with MNP and PNGTS, and is transported on TGP to the LDC city gate (see Table 9). LDCs are assumed to contract for winter season supply priced at the AGT Citygates index plus a fixed premium.

Table 9. Transmission costs for Dracut supply

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
TGP	Dracut	TGP Zone 6	0.137	0.029	0.1%

Resource 4: Delivered gas supplies (northern New England)

The northern New England LDCs that are connected to MNP and PNGTS contract for firm gas winter-season gas supply delivered at their citygates. We assume that the delivered gas cost is the AGT Citygates price plus a fixed premium.

Resource 5. On-system peaking resources (northern New England and Vermont)

The larger LDCs in northern New England (Northern Utilities and EnergyNorth) use LNG trucked to satellite peaking facilities to meet winter gas requirements. When peak-period requirements increase, these LDCs contract for additional LNG supplies to cycle their limited on-site LNG storage capacity. These

LDCs are also considering new LNG facilities to meet future increases in peak day demand. We assume that the cost of gas from an LNG peaking facility is the average AGT Citygates price for the peak winter months, plus a fixed premium. The peaking costs for Vermont are based on a forecast of propane prices.

Other sources of natural gas supply

There are other sources of natural gas supply that do not enter into the AESC 2021 avoided cost calculations.

Underground gas storage

Most New England LDCs hold contracts for seasonal storage service from underground gas storage facilities located in New York, Pennsylvania, and Ontario. With the growth of Marcellus shale gas production, underground storage is used less as a gas supply resource and more as a price hedging and operational balancing tool. Based on our review, LDC decisions to renew or terminate these contracts do not appear to be closely tied to changes in projected customer requirements. As with AESC 2018, we do not include storage service costs in the natural gas avoided cost estimates.

Compressed natural gas

Our review of New England LDC forecasts and supply plans found that several LDCs are considering CNG as a future gas supply resource, but we did not find evidence that CNG is expected to have a significant impact on these LDCs' gas supply costs.

Renewable natural gas

RNG is both a physical gas supply resource and a means of meeting GHG reduction goals. As a supply resource, several projects that would inject RNG into New England LDC distribution systems are proposed, or in active development (see Section 2.3. *New England natural gas market* for additional information). Connecticut LDCs are required to have standard RNG interconnection rules to facilitate future RNG production in that state.[45] However, because RNG is valued for its environmental benefits, RNG is not expected to be a marginal supply resource with production that varies with changes in gas consumption. For this reason, local RNG production is not included as a physical supply resource for the AESC 2021 avoided cost calculations.

There is also a market for RNG attributes. Vermont Gas recently began including the cost of purchasing RNG attributes in the cost of gas adjustment.[46] The VGS Climate Plan includes a goal of reducing GHGs by 30 percent by 2030. To reach this goal, VGS estimates that approximately 20 percent of its retail gas supply will need to be RNG. This includes RNG acquired for its voluntary sales program, and RNG attribute purchases that are included in system gas supply. Because VGS' RNG attribute purchases are

[45] CT PURA Docket No. 19-07-04.

[46] VT PUC Case No. 20-0431-TF, Direct Testimony of Todd Lawliss, p. 12.

tied to increases or decreases in customer requirements, RNG costs are included in the avoided costs for Vermont.

Lost and unaccounted for gas

The total quantity of gas measured at customer meters is generally lower than the measured quantity the LDC receives into its system because of lost and unaccounted for gas (LAUF). For New England LDCs, the difference between measured receipts and deliveries is typically between 1 and 2 percent. LAUF causes the gas requirement at the LDC citygate to be slightly greater than the amount delivered to customers, which increases gas supply costs. We use a LAUF factor of 1.75 percent for all regions outside of Vermont, and a 1.0 percent LAUF factor for VGS.

Natural gas distribution margin

Natural gas distribution systems are designed to meet the projected peak hourly requirements of the LDC's firm customers. When gas use is increasing, LDCs expand capacity by adding new mains, by replacing existing mains with larger-diameter pipe, or by replacing older mains with pipe that can be operated at a higher pressure. Efficiency measures that lower peak gas use avoid the cost of new facilities and associated increases in operation and maintenance (O&M) costs.[47]

LDC marginal cost studies use econometric analysis and engineering estimates to calculate the relationship between expenditures for plant and O&M and changes in peak day demand. The results from these studies are used to design rates and to set floors for the rates charged under special contracts. For AESC 2021 we use the results from recent marginal cost studies prepared by New England LDCs. These are presented in Table 10, which also shows the avoidable LDC margins for southern New England that were used for AESC 2018.[48]

[47] Some mains-replacement projects reduce leakage risk and hence maintenance costs; it is not clear to what extent load growth results in more mains replacement, as opposed to changes in the order of replacements.

[48] AESC 2018 used marginal costs from a recent LDC rate case to estimate the portion of the distribution rate for each class of customer that was related to changes in system capacity. These percentages were then applied to average distribution margins for each New England region. Average distribution margins were calculated by subtracting the citygate natural gas price from the residential, commercial, and industrial prices that are reported by EIA for each state.

Table 10. Marginal distribution capacity cost by customer class (2021 $ per MMBtu)

Company	Docket Number	Residential		Commercial / Industrial		Annual Use (Bcf)
		Non-Heating	*Heating*	*High Load Factor*	*Low Load Factor*	
National Grid (Boston Gas)	17-170	0.960	1.327	0.861	1.391	95.4
National Grid (Colonial Gas)	17-170	1.000	1.418	0.960	1.511	23.8
Berkshire Gas	18-40	0.959	1.518	0.661	1.531	7.6
Eversource Gas	18-45	0.453	0.694	0.387	0.744	51.8
NSTAR Gas	19-120	1.521	2.205	1.128	2.122	51.7
EnergyNorth	DG 20-105	0.937	1.607	0.544	1.597	15.7
Northern - Maine	2019-00092	0.635	0.817	0.301	0.708	10.8
Weighted Average		0.96	1.39	0.78	1.41	
AESC 2018 (2018 $/MMBtu)		0.33	1.09	0.42	0.75	
AESC 2018 (2021 $/MMBtu)		0.35	1.15	0.44	0.79	

2.5. Avoided natural gas costs by end-use

A summary of the natural gas avoided cost estimates is shown in Table 11, Table 12, and Table 13. Avoided costs are developed for three regions: southern New England (Connecticut, Massachusetts, Rhode Island), northern New England (Maine, New Hampshire), and Vermont. Vermont is shown separately because it uses a different avoided gas cost methodology. The results are shown with and without the avoided LDC margin and are compared to the values from AESC 2018.

Table 11. Avoided costs of gas for retail customers by end-use assuming no avoidable margin (2021 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end-uses
	Non Heating	*Hot Water*	*Heating*	*All*	*Non Heating*	*Heating*	*All*	
Southern New England								
AESC 2018	$6.16	$8.09	$8.64	$8.16	$6.98	$8.12	$7.62	$7.91
AESC 2021	$4.67	$5.52	$7.42	$6.63	$5.60	$6.86	$6.31	$6.48
2018 to 2021 change	*-24%*	*-32%*	*-14%*	*-19%*	*-20%*	*-15%*	*-17%*	*-18%*
Northern New England								
AESC 2018	$5.95	$7.74	$8.24	$7.80	$6.71	$7.77	$7.31	$7.57
AESC 2021	$4.51	$5.39	$7.38	$6.55	$5.48	$6.79	$6.22	$6.39
2018 to 2021 change	*-24%*	*-30%*	*-11%*	*-16%*	*-18%*	*-13%*	*-15%*	*-16%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Table 12. Avoided costs of gas for retail customers by end-use assuming some avoidable margin (2021 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end-uses
	Non Heating	*Hot Water*	*Heating*	*All*	*Non Heating*	*Heating*	*All*	
Southern New England								
AESC 2018	$6.51	$8.31	$9.66	$9.04	$7.37	$8.79	$8.17	$8.61
AESC 2021	$5.63	$6.48	$8.81	$7.86	$6.38	$8.27	$7.45	$7.67
2018 to 2021 change	*-14%*	*-22%*	*-9%*	*-13%*	*-13%*	*-6%*	*-9%*	*-11%*
Northern New England								
AESC 2018	$6.28	$8.06	$9.30	$8.73	$7.01	$8.30	$7.73	$8.06
AESC 2021	$5.47	$6.35	$8.76	$7.79	$6.26	$8.19	$7.35	$7.58
2018 to 2021 change	*-13%*	*-21%*	*-6%*	*-11%*	*-11%*	*-1%*	*-5%*	*-6%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Table 13. Avoided costs of gas for retail customers by end-use for Vermont (2021 $ per MMBtu)

	All sectors			
	Design Day	*Peak Days*	*Remaining Winter*	*Shoulder/ Summer*
Vermont				
AESC 2018	$591.58	$27.68	$5.15	$4.72
AESC 2021	$556.10	$17.08	$5.11	$4.75
2018 to 2021 change	*-6%*	*-38%*	*-1%*	*1%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Southern New England and Northern New England

The AESC 2021 avoided cost estimates are lower than the AESC 2018 estimates, but the change in the avoided costs is not as large as the change in the Henry Hub and Algonquin Citygate commodity price forecasts. The main reason is that the cost of expanding natural gas pipeline capacity into New England continues to rise. For AESC 2021, the incremental cost to expand capacity on PNGTS is assumed to be $0.85 per MMBtu, which is 40 percent higher than the transportation charge that was used for AESC 2018. The final rates charged for AGT's Atlantic Bridge expansion project are 14 percent higher than the previous estimate. Because pipeline operators recover capital costs and most operating costs through a fixed monthly charge, the impact of the higher incremental pipeline charges is amplified for lower load factor end-uses, such as residential heating.

Comparing the two Southern New England and Northern New England regions, because the marginal gas transmission path used to calculate the avoided costs for both northern New England and southern New England runs from the Dawn Hub in Ontario through northern New Hampshire, additional gas pipeline charges cause the avoided costs for southern New England to be slightly higher. However, the difference in avoided costs between southern New England and northern New England is smaller for AESC 2021 than for AESC 2018.

Vermont

The natural gas avoided cost estimates for Vermont use the end-use costing periods and methodology developed for previous AESC studies. The Design Day avoided cost is the marginal upstream supply and delivery cost, plus the marginal LDC transmission cost. The Canadian pipeline tolls that set the upstream delivery costs for VGS are slightly lower for AESC 2021 than for AESC 2018, due in part to the change in the Canadian dollar exchange rate. The avoided cost for the remaining nine Peak Days reflects the lower delivered cost of propane for the VGS peaking facility.

3. FUEL OIL AND OTHER FUEL COSTS

In this chapter, we present the avoided fuel oil and other fuel costs used for AESC 2021, compare those estimates with AESC 2018, and identify the data sources used.

This section analyzes oil prices in $/MMBtu for the four sectors: electric generation, residential, commercial, and industrial. Prices are developed for the following grades: distillate fuel oils (No.2 and No. 4), residual fuel oils (No. 6), and biofuel blends.[49] Also included are cord wood, wood pellets, kerosene, and propane in the residential heating applications. New to AESC 2021, we also investigate avoided costs for motor gasoline and diesel used for transportation.

In general, we find that avoided levelized costs for all fuels considered in this category are moderately higher than what was estimated in AESC 2018. In AESC 2021 we follow the EIA Short Term Energy Outlook (STEO) for one year and then directly transition to the 2021 AEO forecast. We chose these data sources for the near term to represent current market conditions and to capture the effects of the COVID-19 pandemic. In contrast, in AESC 2018 we followed the STEO and NYMEX market futures for two years and then transitioned over several years to the most recent AEO forecast.

3.1. Results and comparison with AESC 2018

Table 14 compares the levelized avoided fuel costs for AESC 2021 with those used for AESC 2018. Annual avoided fuel costs are detailed in Appendix D: *Detailed Oil and Other Fuels Outputs*. The Synapse Team based the results for the oil-based fuels on the most recent New England State Energy Data System (SEDS) prices. We then adjusted the results based on the crude oil price trends as discussed above and the AEO 2020 Reference Case projections for New England. Residential distillate prices are 2.9 percent greater, while Commercial distillate prices are 14.3 percent higher and commercial residual prices are 8.2 percent lower (this decrease is due to a drop in recent historical prices for this fuel product). Propane prices are higher, representing recent increases in the SEDS price data. Kerosene, a fuel with a very modest market share, shows a significant increase based on the most recent SEDS data with a price midway between that of distillate and propane.

Wood pellet prices are about the same, reflecting current market conditions. Cord wood, whose price and quality can vary widely, shows a significant price increase based on recent prices. However, these prices are below those of wood pellets. Note that all these prices reflect the fuel heat content and do not adjust for relative efficiencies and delivered energy. This analysis uses SEDS values for the starting points, adjusted for current and near-term national prices from STEO. The prices then follow the trajectory of the AEO 2021 Reference case prices going forward.[50]

[49] For the purposes of AESC 2021, biofuels blended in heating oil include B5 and B20.

[50] See https://www.eia.gov/state/seds/ for more information about the EIA State Energy Data System (SEDS).

Table 14. Comparison of avoided costs of retail fuels (15-year levelized, 2021 $ per MMBtu)

	Residential						Commercial		Transportation	
	No. 2 Distill-ate	Pro-pane	Kero-sene	Bio-Fuel (B20)	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Resid-ual	Motor Gasoline	Motor Diesel
AESC 2018	$23.36	$32.78	$20.95	$24.06	$14.12	$22.76	$19.46	$17.13	-	-
AESC 2021	$24.04	$38.79	$29.59	$21.64	$20.84	$22.47	$22.25	$15.74	$22.07	$22.76
Percent change	2.9%	18.3%	41.3%	-10.1%	47.6%	-1.3%	14.3%	-8.2%	-	-

3.2. Forecast of crude oil prices

The primary factor driving avoided fuel oil costs and fuel oil prices is the price of crude oil. For AESC 2021, we rely on EIA's STEO and projections from the 2021 AEO Reference case (see Chapter 0:

Avoided Natural Gas Costs for more information about the analogous gas price forecast). This is a similar methodology to that used in the 2018 AESC study.

For near-term projections in AESC 2021, we rely on data from the most recent STEO forecast for West Texas Intermediate (WTI) crude oil. We then transition to the AEO 2021 Reference case price projections in 2022. The approach is similar to that used for the natural gas price forecast, but it differs in that the markets have different sources of production and distribution. The oil markets are much more global and fluid than those for natural gas.

The COVID-19 pandemic has reduced fossil fuel consumption world-wide and prices have fallen as supply exceeds demand. In the January 2021 edition of the STEO, the oil price forecast is about $45 per barrel through 2022. However, the uncertainty is quite large, as shown in Figure 8. We also reviewed the NYMEX oil futures for WTI (see Figure 9), which were occasionally used in past AESC studies to adjust or to verify the forecast. These values are similar to the January 2021 STEO in the near term, but then decline in both nominal and real dollar terms. This is odd market behavior and probably not indicative of likely future prices. Thus we make no use of this information in AESC 2021. For short-term prices, we ultimately rely on the STEO forecast because that incorporates an informed analysis of a wide variety of data, including the futures.[51]

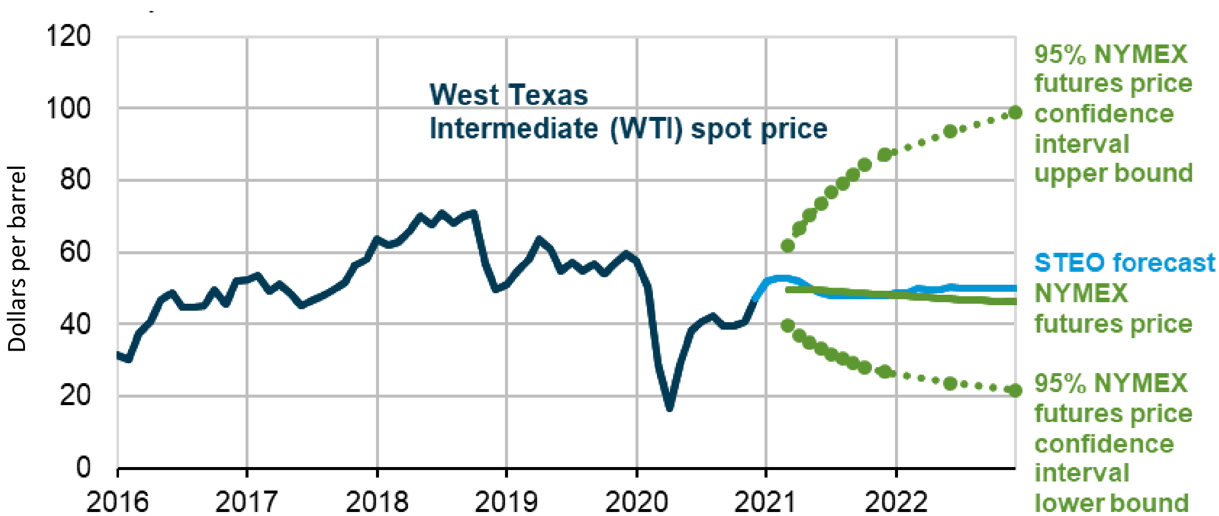
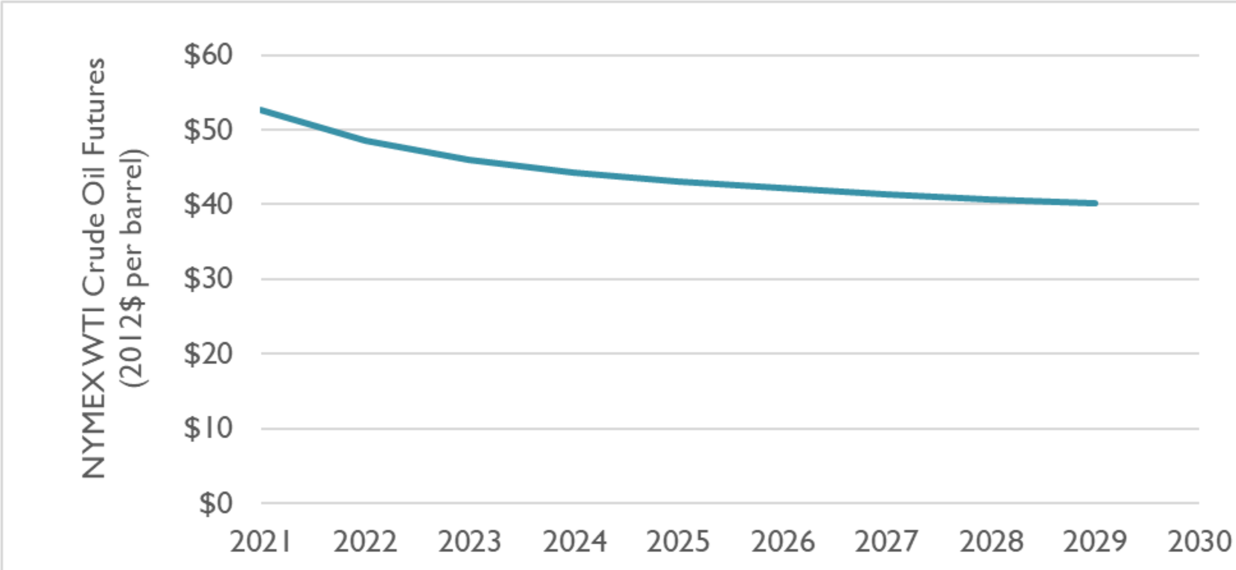


Figure 8. Forecast for West Texas Intermediate crude oil with NYMEX confidence intervals

Source: Reproduced from the January 2021 edition of EIA's Short-Term Energy Outlook. Available at <u>*https://www.eia.gov/outlooks/steo/*</u> *Retrieved January 30, 2021. EIA note: "Confidence interval derived from options market information for the five trading days ending Jan 7, 2021. Intervals not calculated for months with sparse trading in near-the-money options contracts."*

[51] U.S. EIA. Last accessed March 10, 2021. "Short Term Energy Outlooks" *eia.gov.* Available at https://www.eia.gov/outlooks/steo/marketreview/crude.php.

Figure 9. NYMEX oil futures for West Texas Intermediate (WTI) crude oil

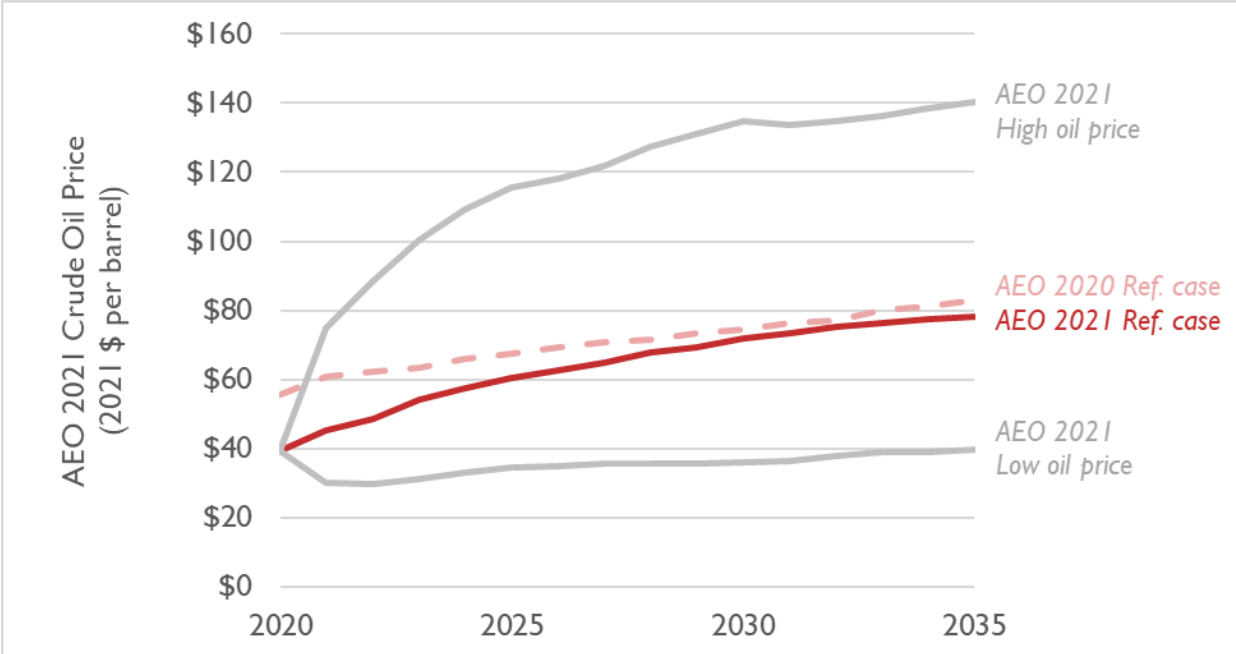


Source: CME Group, https://www.cmegroup.com/market-data/settlements.html?redirect=/market-data/settlements/index.html, Retrieved February 2, 2021.

Figure 10 shows prices for WTI crude oil from a number of scenarios in AEO 2021.[52] Oil prices rise modestly in the Reference case but differ substantially in the High and Low Oil Price scenarios. This represents the uncertainty about future oil prices. The 2020 price of oil in AEO 2021 (about $40 per barrel) is about two-thirds the price projected in AEO 2020 but increases up to similar levels by 2030.

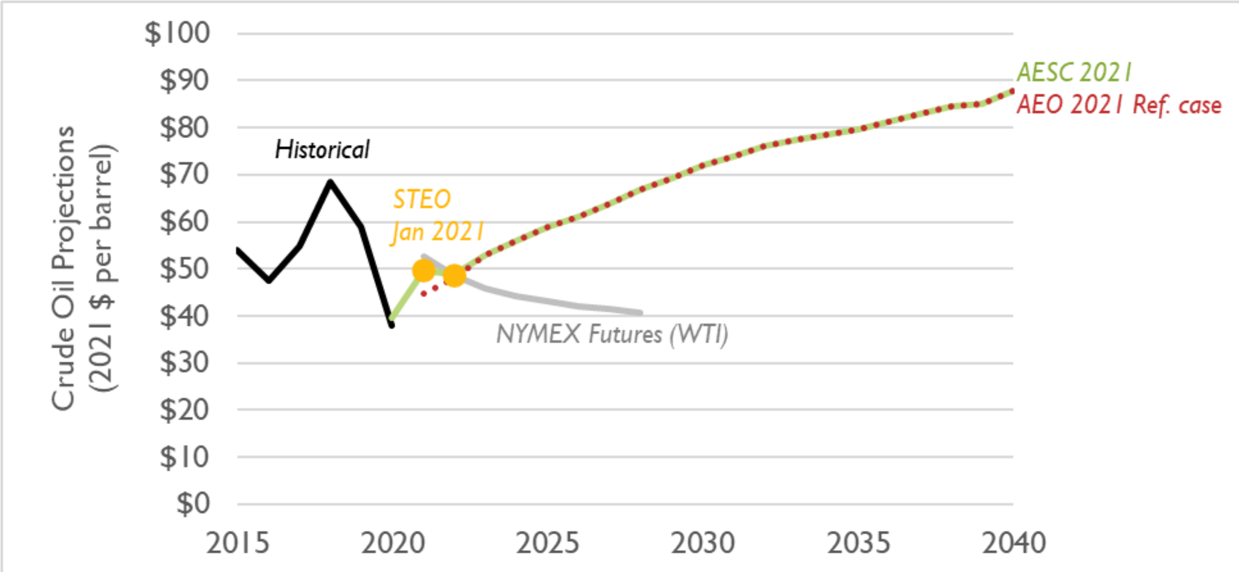
[52] AEO 2020 does not present WTI crude oil prices. Price shown for AEO 2020 is for Brent.

Figure 10. Oil prices projected in various AEO 2021 scenarios



The current short-term forecasts and futures markets do not indicate much increase in crude oil prices over the next several years. However, AEO projections are based on fundamental resource base analyses, and thus it is reasonable to expect higher future oil prices in the medium to long term. For AESC 2021, we use STEO for the near term (2021) and AEO 2021 for the medium and long terms (2022 and all subsequent years) (see Figure 11). The annual real rate of price increase is about 2 percent per year. This forecast is not meant to predict the actual price in any given year, but rather to represent a mid-point average of fluctuating prices.

Figure 11. Crude oil prices, historical, forecast, and AESC 2021



3.3. Forecast of fuel prices

For AESC 2021, starting prices for fuel prices for electric generation and other end-uses are based on historical prices for the various fuels and sectors from SEDS (see Table 15). SEDS represents a comprehensive compilation of the actual prices and consumption. For the electric sector, we verify this with the EIA database of fuel costs for electric generation. Investigation of recent wood prices found delivered wood pellets to be in the range of $18 per MMBtu.[53] Prices for cord wood and wood chips at the residential level are not readily available and vary widely both in cost and heat value.

Data in EIA's SEDS database is provided at the state level. We looked at nine years (2010–2018) of historical data to determine if there are significant variations between the New England states. No consistent and significant state variations are apparent, and except for propane, prices in New England closely resemble national average prices.

[53] New Hampshire Office of Strategic Initiatives. "Fuel Prices," accessed August 31, 2020. Available at: https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm.

Table 15. SEDS New England fuel prices in 2018 by end-use sector in 2018 (2021 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	20.8	20.2	19.0	24.8	16.6
Kerosene	25.6	25.6	16.0	-	-
LPG (Propane)	36.8	19.0	20.2	19.8	-
Residual fuel oil	-	11.6	13.9	-	7.9
Motor Gasoline	-	24.4	24.4	24.4	-
Wood	17.9	-	-	-	-
Wood & Waste	-	22.4	22.4	-	-

AEO 2021 and other EIA documents do not generally make a distinction between state-level prices for specific grades of fuel oil. Instead, they simply report on high-level categories of Distillate Fuel Oil and Residual Fuel Oil. However, the grade mix between sectors does vary and is reflected to some degree in the prices for those sectors.

In terms of the AESC grade categories, we use the following mapping: No. 2 grade is distillate fuel oil used in the residential sector; No. 4 is distillate fuel oil used in the other sectors; and No. 6 is residual fuel oil used in the commercial, industrial, and electric sectors. Definitions of the EIA fuel oil categories can be found on the EIA website.[54] This is the same mapping applied in the 2018 AESC Study.

AEO 2021 does not provide a forecast of New England regional prices for biofuel B5 and B20 blends, as these blends represent a small portion of the New England market. Both B5 and B20 are mixes of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g., soybeans). The number in their name is the percent of agricultural-derived component. Thus "B5" and "B20" represent products with a 5 percent and a 20 percent agricultural-derived component, respectively. They are both similar to No. 2 fuel oil and are used primarily for heating. Each of these fuels has both advantages and disadvantages relative to No. 2 fuel oil. Their advantages include lower GHG emissions per MMBtu of fuel consumed,[55] more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents, equipment effects, and concerns about the long-term supply of agricultural source feedstocks.

Per ASTM D396, fuel oils for home heating and boiler applications may be blended with up to 5 percent biodiesel below the rack.[56, 57] Marketers are not required to disclose information on biodiesel content below these levels. While the AEO forecast for fuel oil does not reflect any inherent biodiesel content, the current price premium for B99-B100 biodiesel is $0.90 per gallon, or an implied 7 cents per gallon for

[54] EIA Fuel oil definitions: https://www.eia.gov/tools/glossary/index.php?id=N.

[55] The CO_2 emissions from the bio component of the fuel are not counted as contributing to global climate change.

[56] ASTM International. "ASTM Sets the Standard for Biodiesel." Jan 2009. Available at: http://www.astm.org/SNEWS/JF_2009/nelson_jf09.html.

[57] "Below the rack" refers to blending at the refinery, before fuel is sold to wholesalers.

the B5 blend. However, the current price for B20 is $0.25 per gallon below diesel ($2.36 vs. $2.61).[58] B20 prices have been below diesel prices by similar levels since 2018. We thus project that B20 prices will be 10 percent below diesel prices in the future, and that B5 prices will have neither a discount nor a premium.

The SEDS data show no differences in residential wood prices between the New England states. As the starting basis for wood prices, AESC 2021 uses recent data from New Hampshire.[59] Actual wood prices and wood quality can vary widely, and we recommend that anyone interested in this issue carry out an independent investigation of local wood prices. In previous AESC studies, we linked the future wood fuel price changes to that of distillate oil and we do so again here.

Because recent oil prices have changed so much since the 2018 SEDS data, we adjusted those prices to represent the changes in oil prices since then. The AESC 2021 starting prices are shown in the following table.

Table 16. New England fuel prices in 2021 by end-use sector (2021 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	19.1	20.9	20.0	20.0	18.5
Kerosene	23.6	26.4	16.8		
LPG (Propane)	33.9	19.7	21.2	15.9	
Residual fuel oil	-	12.0	14.6		8.8
Motor Gasoline	-	25.3	25.6	19.7	
Wood	17.9				
Wood & Waste	-	23.2	23.6		

Prices in future years start with the base year prices as indicated above and then increase following the trajectory for the oil price forecast, as shown in Figure 11. They then follow that same relative trajectory and match the AEO 2021 New England price projections and trends in 2022 and future years. The AESC 2021 starting prices are based on 2018 SEDS historical data and actual 2020 prices, but the changes over the analysis period are based on the AEO projections.[60]

Since fuel oil prices do not show meaningful variations by month or season, we have not developed monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons, our forecast does not address volatility in the prices of these fuels.

[58] U.S. Department of Energy Alternative Fuels Data Center, April 2020 prices. https://www.afdc.energy.gov/fuels/prices.html.

[59] New Hampshire Office of Strategic Initiative, "Fuel Prices." Available at https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm. Accessed August 31, 2020.

[60] In cases where there are noticeable differences between the SEDS and the AEO prices we have relied on the SEDS prices, as these represent actual reported costs.

3.4. Avoided costs

For the avoided costs for fuel oil products and other fuels by end-use, we used the prices as discussed above and the consumption as projected in AEO 2021. The consumption of these fuels is not expected to increase significantly over the study period. Moreover, the supply systems are flexible and diverse, and they are not subject to the capacity- or time-based constraints associated with electricity and natural gas. Thus, we believe the market prices provide an appropriate representation of the avoided costs.

For petroleum-related fuels, we started with the costs of those fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum-related fuel that AEO projects will be used in that sector. We estimated that the crude oil price component of these projected prices is the portion that can be avoided through demand-side management (DSM) programs. For other fuels, we used the projected regional prices multiplied by the consumption of those fuels as projected by AEO, with appropriate fractional adjustments based on the SEDS historical data. Consistent with prior AESC studies, we model the full cost of those fuels as avoidable.

3.5. Greenhouse gas and criteria pollutant emissions

Table 17 provides carbon dioxide (CO_2) emission rates for the various fuels analyzed in this chapter. This table defines the CO_2 emission rate for wood fuels as zero. This essentially a placeholder value, as there are differing views about the GHG impacts of wood fuels. Additional information on emissions rates can be found in Appendix G: *Marginal Emission Rates and Non-embedded Environmental Cost Detail*.

Table 17. CO_2 emission rates for non-electric fuels (lb per MMBtu)

Fuel	CO_2 Emission Rate
Distillate fuel oil	161
B5 Biofuel	153
B20 Biofuel	129
Kerosene	159
LPG	139
RFO	173
Transportation Diesel	161
Gasoline	157
Wood	zero
Wood & Waste	zero

Note: Biofuel rates are based on the fossil fuel fraction. The direct CO_2 emission rate for wood combustion depends strongly on wood type and moisture content, but a rough range would be 200–250 lbs/MMBtu. Version February 2016.
Sources: Emission rates for petroleum products from EIA https://www.eia.gov/environment/emissions/co2_vol_mass.php.

Combustion of these fuels also produces sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions. Most of the available emission data is quite old and the impacts are very small. However, for reference we provide the emission rates from AESC 2018 (see Table 18). Most of the Northeast has switched to Ultra-

Low Sulfur Diesel (ULSD) fuel oil, which consists of only 50 or 15 parts per million (ppm) of sulfur.[61] By contrast, 1 percent sulfur oil—historically in wide use in New England—contains 10,000 ppm of sulfur. The shift to ULSD reduces the SO_2 emissions by a factor of over 600. Distillate oil at 15 ppm sulfur is equivalent to 0.0016 lb SO_2 per MMBtu, which rounds to the 0.002 lb SO_2 per MMBtu, shown in Table 18. Heavier oils will likely have higher sulfur content and the emission rates should be adjusted accordingly based on their actual characteristics.

Table 18. SO_2 and NO_X emission factors (lb per MMBtu)

Emission Rates of Significant Pollutants from Fuel Oil Sector and Fuel	SO_2	NO_X	*Notes*
#2 Fuel Oil			*(a)*
Residential, #2 oil	0.002	0.129	
Commercial, #2 oil	0.002	0.171	
Industrial, #2 oil	0.002	0.171	
Kerosene—Residential heating	0.152	0.129	*(b)*
Wood—Residential heating	0.020	0.341	*(c)*

Notes: For fuel oil, we assumed sulfur content of 15 ppm.
Sources: Table originally from AESC 2015, Exhibit 4-15. Page 4-93. Embedded sources include (a) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/ (for SO_2 and NO_X); (b) AESC 2013; (c) James Houck and Brian Eagle, OMNI Environmental Services, Inc., Control Analysis and Document for Residential Wood Combustion in the MANE-VU Region, December 19, 2006. http://www.marama.org/publications_folder/ResWoodCombustion/RWC_FinalReport_121906.pdf.

The table below provides emission assumptions for gasoline and diesel used in transportation. Note that criteria pollutants from the transportation sector can vary substantially based on vehicle type and age. These numbers are based on national averages for vehicles on the road in 2018 and may change as new vehicle emission standards are implemented in the future and older vehicles are retired.

Table 19. Transportation fuel emission factors (lb per MMBtu)

Fuel	NO_x	HC	CO	PM2.5 (Exhaust)	PM2.5 (Brake and Tire)
Gasoline	0.124	0.137	1.620	0.003	0.001
Diesel	0.717	0.077	0.239	0.026	0.002

Notes: NO_X = nitrogen oxides; HC = hydrocarbons; CO = carbon monoxide; PM2.5 = particulate matter with diameter <= 2.5 micrometers. Gasoline includes light-duty vehicles, light-duty trucks, and motorcycles. Diesel includes trucks of six tires or more. combination trucks, and buses.
Sources: Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the U.S. Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. See Tables 1-35, 4-43, and 4-6M.

[61] U.S. EIA. April 18, 2012. “Sulfur Content of Heating Oil to be Reduced in Northeastern States.” *eia.gov.* Available at https://www.eia.gov/todayinenergy/detail.php?id=5890.

Vehicle emission rates vary at the state level for a variety of factors including vehicle mix and inspection programs (for example, see the data in Table 20).[62] U.S. Department of Transportation does not publish state emission data, but this data may be available from state transportation or environmental agencies.[63]

Table 20. Transportation fuel 2018 emission factors (grams per mile)

Pollutant	Gasoline				Diesel		
	Light-duty vehicles	*Light-duty trucks*	*Heavy-duty vehicles*	*Motor-cycles*	*Light-duty vehicles*	*Light-duty trucks*	*Heavy-duty vehicles*
HC	0.350	0.421	1.160	2.544	0.183	0.324	0.645
CO	3.941	5.655	21.352	13.58	2.663	2.754	1.994
NO_X	0.289	0.478	1.416	0.719	0.153	1.321	5.971
Exhaust $PM_{2.5}$	0.008	0.010	0.030	0.024	0.004	0.045	0.213
Brakewear $PM_{2.5}$	0.003	0.003	0.009	0.001	0.003	0.003	0.013
Tirewear $PM_{2.5}$	0.001	0.001	0.002	0.001	0.001	0.002	0.004

Sources: Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the U.S. Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. Table, 4-43.

62 In addition, there may be volatile organic compound (VOC) emissions from fuel oil handling and from wood fuel combustion. These emissions are not quantified as part of the AESC 2021 study.

63 U.S. Environmental Protection Agency's (EPA) MOVES model is one example of such a resource. https://www.epa.gov/moves.

4. Common Electric Assumptions

The following section contains input assumptions which are common to the calculations of avoided electric energy, avoided electric capacity, and avoided RPS compliance.

One of the main tasks of the AESC 2021 study is to estimate the electricity supply costs that would be avoided by reducing retail sales of electricity through energy efficiency initiatives or other emerging DSM programs. It includes methodologies, assumptions, and sources relating to the modeling frameworks, electricity demand, transmission, renewable policies, generic resource additions, known and anticipated resource additions, and known and anticipated resource retirements.

In addition to differences in underlying natural gas prices and fuel oil prices (discussed in Chapter 0 and Chapter 3, respectively) modeling assumptions in AESC 2021 differ from those used in AESC 2018 in terms of the following:

- Examination of different load trajectories under four counterfactual scenarios
- Lower projections for annual sales (not including impacts associated with building or transportation electrification)
- Inclusion of impacts of transportation electrification in all four counterfactual scenarios
- Updated assumptions on clean energy additions, including substantial updates to new long-term contracting requirements (e.g., for offshore wind and other renewables), modifications to online dates for certain clean energy projects, and updates of other renewable policies including RPS
- Updated assumptions for known and estimated unit retirements as well as unit additions
- Lower projections for compliance prices under RGGI

4.1. AESC 2021 modeling framework

The wholesale energy markets in New England are managed by ISO New England. There are two primary energy markets: (1) the Day-Ahead Market (where the majority of transactions occur) and (2) the Real-Time Market, in which ISO New England balances the remaining differences in energy supplies and demand.[64] On average, prices in these two markets are typically close to one another, although there is a tendency for greater volatility in the Real-Time Market. ISO New England also manages a capacity market, which is an auction-based system that ensures the New England power system has sufficient resources to meet future demand for electricity. Forward Capacity Auctions (FCA) are held each year,

[64] See ISO New England's *2019 Annual Markets Report* for more information at https://www.iso-ne.com/static-assets/documents/2020/06/a6_2019_annual_markets_report.pdf.

three years in advance of a specified future operating period. ISO New England also manages other ancillary markets, including regulation and reserve markets.

AESC 2021 uses three models to concurrently forecast avoided energy market and capacity costs. These models include:

The EnCompass Model

Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that allows for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including the following:

- Short-term scheduling, including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis
- Long-term integrated resource planning, including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

EnCompass provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions described in this document. Synapse has populated the model using the *EnCompass National Database*, created by Horizons Energy. Horizons Energy benchmarked its comprehensive dataset across the 21 North American Electric Reliability Corporation (NERC) Assessment Areas and it incorporates market rules and transmission constructs across 76 distinct zonal pricing points. Synapse uses EnCompass to optimize the generation mix in New England and to estimate the costs of a changing energy system over time, absent any incremental energy efficiency or DSM measures. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

EnCompass modeling topology

EnCompass, like other production-cost and capacity-expansion models, represents load and generation by mapping regional projections for system demand and specific generating units to aggregated geographical regions. These load and generation areas are then linked by transmission areas to create an aggregated balancing area. Table 21 shows load and generation areas to be reported on in AESC 2021 and Table 22 details modeled load and generation areas. This is the same modeling topology as that used in AESC 2018. For AESC 2021, we use load-weighted averages to translate modeling zones into reporting zones. While some zones under each topology are close matches, other reporting zones are made up of a number of different modeling zones. The percentages for weighting percentages are based on locations of pnodes in specific states and modeling zones (see Table 23).[65] These weighting percentages are updated with 2019 nodal data that are similar, but not identical to, the weightings used in AESC 2018 (which was based on 2016 nodal data).

Table 21. Reporting zones in AESC 2021

	AESC Reporting Zones
1	Maine
2	Vermont
3	New Hampshire
4	Connecticut
4a	Southwest Connecticut (including Norwalk-Stamford)
4b	Rest of Connecticut (Northeast)
5	Rhode Island
6	Massachusetts
6a	SEMA (Southeastern Massachusetts)
6b	WCMA (West-Central Massachusetts)
6c	NEMA (Northeastern Massachusetts)

Table 22. Modeled load zones in AESC 2021

EnCompass Region	ISO New England sub-area
NE Maine Northeast	BHE
NE Maine West Central	ME
NE Maine Southeast	SME
NE New Hampshire	NH
NE Vermont	VT
NE Boston	Boston
NE Massachusetts Central	CMA/NEMA
NE Massachusetts West	WMA
NE Massachusetts Southeast	SEMA
NE Rhode Island	RI
NE Connecticut Northeast	CT
NE Connecticut Southwest	SWCT
NE Norwalk Stamford	NOR

[65] Pnode load factors for 2019 are available on the ISO New England website at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/nodal-load-wgts.

Table 23. Translation between EnCompass modeling zones (vertical) and AESC 2021 reporting zones (horizontal)

		ME	NH	RI	VT	All CT	SW CT	NE CT	All MA	SE MA	NE MA	WC MA
NE Maine Northeast	BHE	15%	-	-	-	-	-	-	-	-	-	-
NE Maine West Central	ME	50%	-	-	-	-	-	-	-	-	-	-
NE Maine Southeast	SME	35%	-	-	-	-	-	-	-	-	-	-
NE New Hampshire	NH	-	82%	-	3%	-	-	-	-	-	-	-
NE Vermont	VT	-	16%	-	91%	-	-	-	-	-	-	-
NE Boston	Boston	-	-	-	-	-	-	-	46%	-	100%	1%
NE Mass. Central	CMA/ NEMA	-	3%	-	-	-	-	-	13%	-	-	46%
NE Mass. West	WMA	-	-	-	6%	1%	-	2%	15%	-	-	53%
NE Mass. Southeast	SEMA	-	-	10%	-	-	-	-	20%	77%	-	-
NE Rhode Island	RI	-	-	90%	-	-	-	-	6%	23%	-	-
NE Connecticut Northeast	CT	-	-	-	-	50%	-	98%	-	-	-	-
NE Connecticut Southwest	SWCT	-	-	-	-	32%	66%	-	-	-	-	-
NE Norwalk Stamford	NOR	-	-	-	-	17%	34%	-	-	-	-	-

Notes: Totals may not add due to rounding.

Neighboring regions modeled in this study are New York, Quebec, and the Maritime Provinces. These regions are not represented with unit-specific resolution. Instead, they are represented as a source or sink of import-export flows across existing interfaces in order to reduce modeling run time.[66]

[66] In this analysis, the Maritimes zone includes Emera Maine and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO New England and, therefore, are not included in any of the New England pricing zones used in this study. These regions are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area.

The Renewable Energy Market Outlook Model

In addition to EnCompass, AESC 2021 uses Sustainable Energy Advantage's New England Renewable Energy Market Outlook (REMO), a set of models developed by Sustainable Energy Advantage that estimate forecasts of scenario-specific renewable energy build-outs, as well as REC and clean energy certificate (CEC) price forecasts. Within REMO, Sustainable Energy Advantage can define forecasts for both near-term and long-term project buildout and REC pricing.

Near-term renewable builds are defined as projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. These projects are subject to customized, probabilistic adjustments to account for deployment timing and likelihood of achieving commercial operation. The near-term REC price forecasts are a function of existing, RPS-certified renewable energy supplies, near-term renewable builds, regional RPS demand, alternative compliance payment (ACP) levels in each market, and other dynamic factors. Such factors include banking, borrowing, imports, and discretional curtailment of renewable energy.

The long-term REC price forecasts are based on a supply curve analysis taking into account technical potential, resource cost, and market value of production over the study period. These factors are used to identify the marginal, REC price-setting resource for each year in which new renewable energy builds are called upon. The long-term REC price forecast is estimated to be the marginal cost of entry for each year, meaning the premium requirement for the most expensive renewable generation unit deployed for a given year.

The FCM Model

The AESC 2021 study uses a spreadsheet model to develop FCM auction prices for power years from June 2021 onwards. We coordinate the major input assumptions regarding the forecasts of peak load and available capacity in each power year with the input assumptions used in the Encompass energy market simulation model. General assumptions for this model include the assumption that resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 12 through FCA 15, the assumption that FCM prices will be to a large degree determined by the price of new peaking units, and the assumption that the supply curve in future FCAs feature similar slopes to FCA 15. See Chapter 5: *Avoided Capacity Costs* for more detail on the methodology.

Modeled market rules

The EnCompass model approximates the market rules used in ISO New England. The following sections provide an overview of the model's approach to these rules.

Marginal-cost bidding

In deregulated markets, generation units are assumed to bid marginal cost (opportunity cost of fuel plus variable O&M costs plus opportunity cost of tradable permits). The model prices are based on such representative marginal costs. Notably, the model calculates bid adders to close any gap between energy market revenues and submitted bids. The resulting energy-price outputs are benchmarked against historical and future prices.

Installed capacity

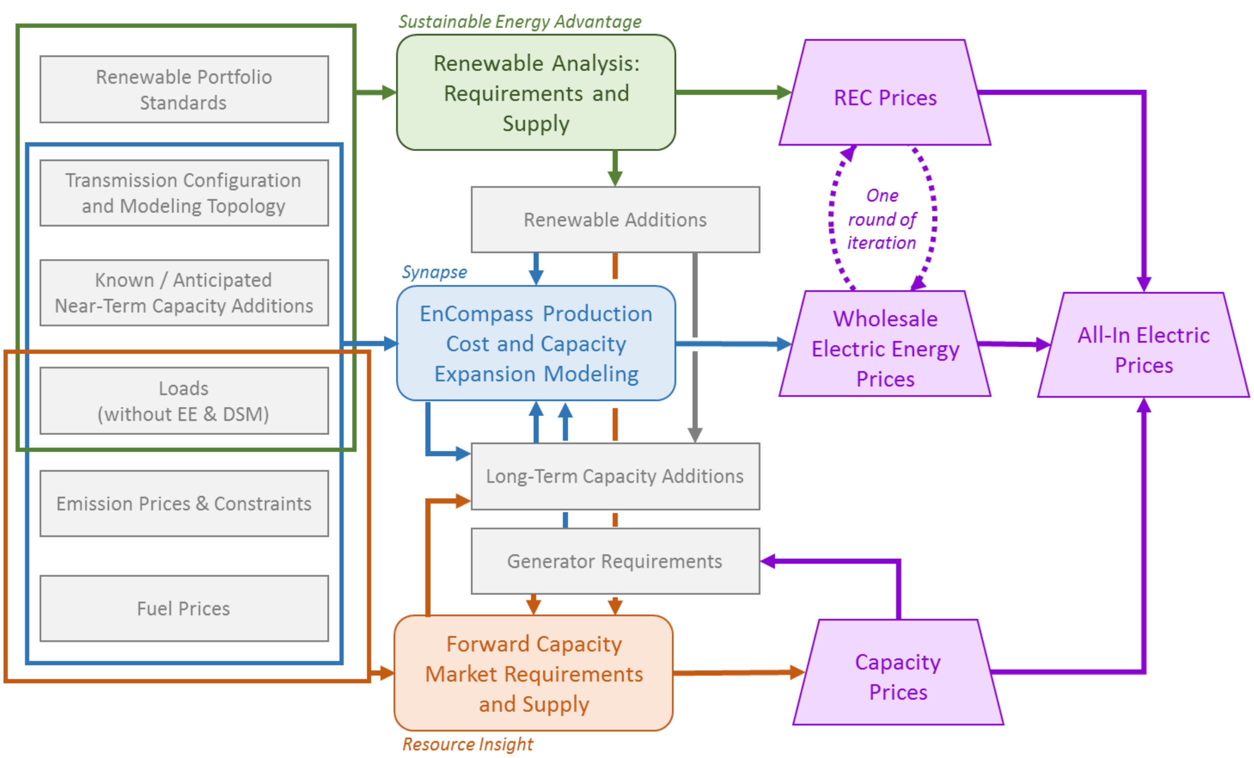
Installed-capacity requirements for the EnCompass model include reserve requirements established by ISO New England on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec installed-capacity credits) are described in Chapter 5: *Avoided Capacity Costs.* Installed capacity for the energy model in each model year is consistent with the values assumed in the FCA analysis, although the values are not necessarily the same due to imports and exports.

Ancillary services

EnCompass allows users to define generating units based on each unit's ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The model allows users to specify these abilities for each unit, at varying levels of granularity. EnCompass allows units to contribute to contingency and reserves requirements, and it considers applicable costs when determining bids.

Figure 12 highlights the interactions between the models used in AESC 2021.

Figure 12. AESC 2021 modeling schematic



Energy Security Initiative

ISO New England proposed a package of new day-ahead reserve products through its *Energy Security Improvements* (ESI) proposal to address concerns over fuel security in the winter. The proposal utilized call options on energy, which have not been used in other regional transmission organizations, to address what the ISO describes as a "misaligned incentives problem" under the current market rules. The Federal Energy Regulatory Commission (FERC) rejected ISO New England's proposal on October 30, 2020 due to concerns about the impact it would have on energy security as measured by metrics such as reserve shortage hours and loss of load, as well as the costs the proposal would impose on consumers.[67] FERC was particularly concerned that ESI would produce reserves on a one-day-ahead timeframe that would not provide resource owners enough time to procure firm fuel supplies. The New England Power Pool (NEPOOL) offered an alternative version of ESI that adjusted some of the reserve products the ISO would procure and reduced the total quantity of reserve product purchases, particularly in the non-winter months. The NEPOOL alternative was projected to be less costly to consumers but was also rejected by FERC because it did not address FERC's concerns with the timing of the reserve procurement and the expected limited impact on reserve shortage hours.[68] ISO New England is reviewing FERC's decision and will be discussing next steps with stakeholders. As of November 2020, timing for next steps was uncertain. We recommend that any impacts attributed to ESI be incorporated in a future AESC study or study update.

Modeling timescale

In EnCompass, REMO, and the FCM Model, we explicitly model 15 years from 2021 through 2035. In order to develop 30-year levelized avoided costs, AESC 2021 continues the trajectory of each avoided cost component through 2050.[69]

For each modeled year, we use the temporal resolutions described below.

For avoided energy costs:

- Each year is first modeled in EnCompass' capacity-expansion construct. In this construct, EnCompass optimizes to determine the most cost-effective capacity additions.[70] We run EnCompass at the resolution of a typical week. This means that EnCompass represents each year from 2021 to 2035 as an aggregation of 12 months, each of which is represented by a typical week, each week of which is represented by five "on peak" days and two "off peak days," and each day of which is represented by a 24-hour chronological dispatch period.

[67] *ISO New England Inc.*, 173 FERC ¶ 61,106 (2020).

[68] 173 FERC ¶ 61,106.

[69] In all cases, this involves extrapolating values through 2055. See Appendix A: *Usage Instructions* for the methodology used.

[70] Note that these capacity additions are limited to generic resource types (described below). Note that we enter other capacity as exogenous additions.

- After running EnCompass in the capacity-expansion construct, we next run it in production-cost mode for a subset of years. EnCompass' production-cost mode uses the capacity-expansion outputs as "seed" data, and it allows the model to better approximate unit commitment over the course of a year. In this construct, we use an 8,760-hour resolution for each year between 2021 and 2035.

- Hourly 8,760 data are then aggregated using load-weighted averages to the four time periods used for reporting in previous AESC studies (summer on-peak, summer off-peak, winter on-peak, and winter off-peak).[71]

For avoided capacity costs:

- Program administrators can claim avoided capacity by either bidding capacity (cleared) into the FCAs, or by reducing peak summer loads through non-bid capacity (uncleared) (which then becomes phased-in load forecasts for subsequent FCAs). Hence, all avoided capacity will be stated per kW of peak load reduction. The effect of uncleared capacity for demand response will vary with the number days each summer for which peak load is reduced and the number of years for which the load reduction continues (see Appendix J: for more information).

- The capacity value of passive demand resource (such as an energy efficiency program) or an active demand resource cleared in the capacity market will be determined by the capacity value accepted by the ISO. The user of the model will need to estimate how much capacity value will be recognized by the ISO for each resource that will be bid into the market. The capacity value of energy efficiency that is not cleared in the capacity market will be approximately the load reduction of the measure at the ISO's normal peak conditions.[72]

- ISO New England models peak load by regressing daily peak in each day of July and August on a number of variables, including monthly energy, WTHI,[2] a time trend × WTHI, and dummies for weekends and holidays (also × WTHI). While it is difficult to determine exactly how load reductions in various summer conditions will affect the peak forecast, an energy efficiency measure that reduces load throughout the summer or in the days with above-average WTHI should fully affect the load forecast. Load management that affects only a few summer days would have a much smaller impact on the load forecast.

[71] These time periods are defined by ISO New England as follows: Winter on-peak is October through May, weekdays from 7am to 11pm; winter off-peak is October through May, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays; summer on-peak is June through September, weekdays from 7 a.m. to 11 p.m.; and summer off-peak is June through September, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays.

[72] The normal peak conditions are defined as a weighted temperature-humidity index (WTHI) for the day of 79.9°, where the weighting is (10 × the current day's THI, plus 5 × the previous day's THI, plus 2 × the THI two days earlier) ÷ 17. The daily THI is 0.5 × temperature +0.3 × dewpoint +15. The THIs are computed for eight cities (Boston, Hartford, Providence, Portland, Manchester NH, Burlington VT, Springfield, and Worcester) and weighted by zonal loads.

For DRIPE:

- Energy DRIPE is estimated as proportional to avoided energy cost. Thus, energy DRIPE can be applied to any level of disaggregated avoided energy cost.
- Capacity DRIPE is stated per kW of peak load reduction, for bid resources and for non-bid load reductions. Those values can be attributed to programs in the same manner as the avoided capacity costs, and with the same computations for demand response.
- Natural gas supply DRIPE and oil DRIPE are intrinsically annual values.
- Natural gas basis DRIPE is associated with high-load days in the winter, for both electric and natural gas loads.

Model calibration

Because one of the main outputs of the AESC 2021 study is the estimation of avoided electric energy costs, it is essential that modeling outputs for wholesale energy prices are in line with actual, recent historical wholesale energy prices. In this analysis, we compare the model's projected regional hourly price forecasts to 2019 prices in the ISO New England's "SMD" dataset.[73] See Section 6.2: *Benchmarking the EnCompass energy model* for more information on the results of the model calibration for energy costs.

Note that because several of the AESC counterfactuals project futures that lack any incremental energy efficiency installed beyond 2020, prices in future years are likely to substantially diverge from recent historical prices.

4.2. Modeling counterfactuals

The *AESC 2021 User Interface* (a separate Excel workbook) includes hourly values in addition to the four traditional energy costing periods (summer on-peak, summer off-peak, winter on-peak, and winter off-peak).[74] These 8,760 avoided cost values may help refine the quantification of traditional DSM programs that have relied upon avoided cost values from previous AESC studies.

New to the AESC 2021 study is the development of four different counterfactual scenarios for our analysis. Table 24 details the DSM components modeled in each of the counterfactuals. Generally speaking, each of the avoided cost streams is the "but for" costs attributed to the counterfactual scenario, so those specific DSM components are excluded in the specified scenario. For purposes of simplification and comparison, Counterfactual #1 is the counterfactual used for the discussion of many

[73] "SMD" is a legacy acronym referring to "Standard Market Design." Currently, the primary application of this term is in the naming of this dataset. The SMD dataset containing hourly data for 2019 can be found at on the ISO New England website at https://www.iso-ne.com/static-assets/documents/2019/02/2019_smd_hourly.xlsx.

[74] Appendix B: *Detailed Electric Outputs* contains the cost streams associated with the four costing periods consistent with previous AESC studies.

high-level findings and comparisons with previous AESC study results throughout this report. The following two sections on system demand and renewable energy policies describe the assumptions used for each of the DSM components.

Table 24. Modeled counterfactual scenarios in AESC 2021

DSM component included?	Counterfactual #1 *AESC for EE, ADM and building electrification*	Counterfactual #2 *AESC for building electrification only*	Counterfactual #3 *AESC for EE only*	Counterfactual #4 *AESC for EE and ADM only*
Energy Efficiency (EE)	*No*	Yes	*No*	*No*
Active Demand Management (ADM)	*No*	Yes	Yes	*No*
Building electrification	*No*	*No*	Yes	Yes
Transportation electrification	Yes	Yes	Yes	Yes
Distributed generation	Yes	Yes	Yes	Yes

Notes: A "Yes" indicates that the relevant DSM component is included (e.g., modeled) within that counterfactual. A "No" indicates that the DSM component is not incorporated into the modeling in 2021 or any future year. A "No" only removes the programmatic resources associated with each DSM component (e.g., energy efficiency associated with codes and standards is modeled in all scenarios, as is storage or demand response owned or funded by entities other than program administrators).

4.3. New England system demand

Forecasts of annual peak demand and energy used in each of the AESC 2021 models are in large part based on the 50/50 values published by ISO New England in the 2020 *Forecast Report of Capacity, Energy, Loads and Transmission* (CELT) study.[75] However, our forecast includes modifications and enhancements to this forecast. Specifically, our load forecast covers the following components:

- Econometric forecast: This is a projection of energy consumption (in MWh) and peak demand (in MW) related to traditional electric end-uses, based on data provided in ISO New England's 2020 CELT forecast. It also includes historical energy efficiency installed through 2020, but does not include any energy efficiency installed in 2021 or later years. It also does not include impacts from any of the categories discussed below.

- Energy efficiency: This is a projection of energy efficiency measures for 2021 and later years, for all New England states based on data provided in ISO New England's 2020

[75] The "50/50" forecast contains ISO New England's statistically most-likely estimate of future demand. ISO New England also publishes other forecasts for demand, including a 90/10 and a 10/90 forecast, which represent high and low ranges of estimates for demand.

CELT forecast. It is used in counterfactuals that estimate avoided costs for measures *other than* energy efficiency.

- Building electrification: This is a projection of the impacts from residential heat pumps, based on data provided in ISO New England's 2020 CELT forecast. It is used in counterfactuals that estimate avoided costs for measures *other than* building electrification.
- Active demand management: This is a projection of the impacts from demand response and behind-the-meter (BTM) energy storage, based on data in ISO New England's FCM and program data reported by states and utilities. It is used in counterfactuals that estimate avoided costs for measures *other than* active demand management.
- Transportation electrification: This is a projection of the impacts from light-, medium-, and heavy-duty electric vehicles, based on data from Bloomberg New Energy Finance's (BNEF) Electric Vehicle Outlook 2020. It is used in all counterfactuals.
- Distributed generation: This is a projection of the impacts from distributed solar, based on the implied quantities resulting from state renewable policy. It is used in all counterfactuals. See Section 4.4: *Renewable energy* for more information on this topic.

Econometric forecast

The following sections focus on the "econometric" forecast for electricity demand. Generally speaking, this forecast includes futures impacts of measures (such as energy efficiency) installed in past years, as well as future impacts of "traditional" electric end-uses (e.g., not transportation electrification or building electrification).

Annual energy demand

In May 2020, ISO New England released its newest electricity demand forecast, CELT 2020.[76] As in the CELT forecasts before it, in CELT 2020 ISO New England developed a forecast of annual energy for New England as a whole and for each individual state and load zone. These forecasts are based on regression models that integrate inputs on previous annual consumption, real electricity price, real personal income, gross state product, and heating and cooling degree days with data from 1990 through 2019.

To calculate the econometric component of electricity demand in AESC 2021 (e.g., the component of electricity demand driven by factors like population, gross domestic product, and weather—rather than energy efficiency or electrification).[77] We do not rely on the specific MWh demand quantities articulated

[76] Further information about the CELT forecast can be found at ISO New England's website at https://www.iso-ne.com/system-planning/system-plans-studies/celt, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/ and https://www.iso-ne.com/static-assets/documents/2020/04/modeling_procedure_2020.pdf.

[77] Note that ISO New England's econometric forecast can be impacted by the effects of federal energy efficiency standards and other non-programmatic energy efficiency.

in the 2020 CELT study, as these quantities start with a projected level of 2020 demand that will likely exceed actual 2020 demand in part due to the COVID-19 pandemic.

Instead, we examined monthly actual versus projected system demand through July 2020 (see Figure 13).[78] From January through July, actual regionwide system demand was, on average, 7 percent lower than system demand as projected in CELT 2020. These monthly differences range from a high of 12 percent lower than projected in May to a low of 3 percent *greater* than projected in July. These monthly differences are not solely attributable to the COVID-19 pandemic; instead, differences in projections and observed system demand in January, February, and (at least part of) March are likely mostly due to differences in projected versus actual weather.[79]

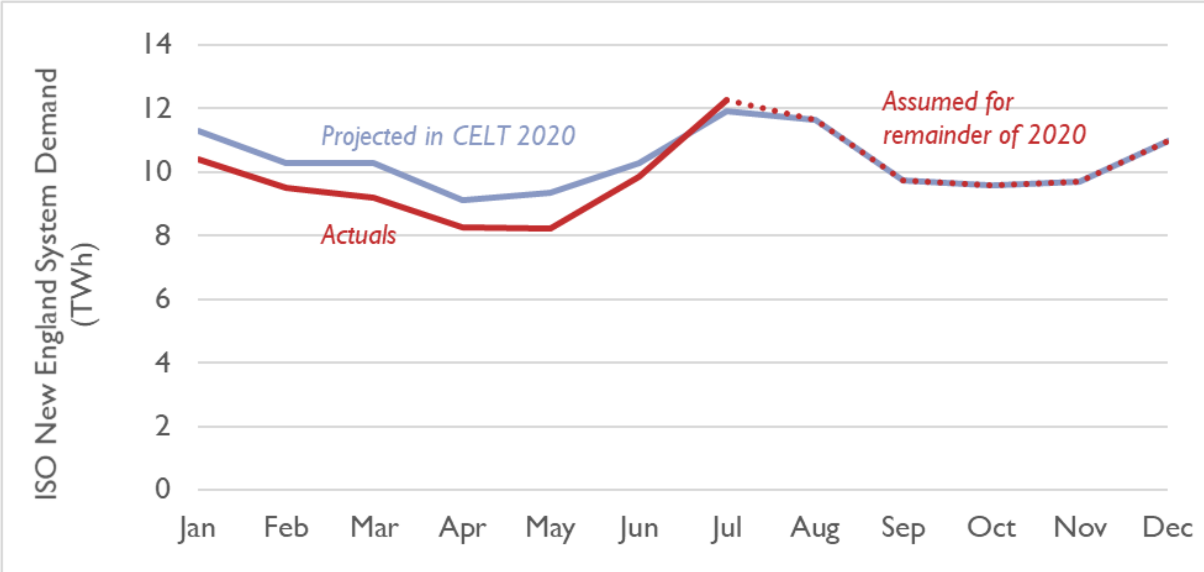
Assuming that system demand returns to projected levels in August through December 2020 (as the June and July data points suggest it may) we find that, for the year as a whole, actual 2020 system demand would be 4 percent lower than projected by CELT 2020. We apply this scaling factor to ISO New England's projection of 2020 Gross Demand (less electrification and incremental energy efficiency) as it is defined in ISO New England's 2020 CELT study to determine a new, adjusted starting point for the AESC 2021 forecast. To create system load values for 2021 through 2029, we apply the compound annual growth rate (CAGR) for 2020 through 2029, as estimated for each of the 13 modeling regions in CELT 2020. To calculate system demands for 2030 through 2035, we apply the CAGR calculated for each region in CELT 2020 for the last five years (2025 through 2029) and compared to AESC 2018 (see Figure 14).[80]

[78] Monthly actual system demand for 2020 is available on ISO New England's website at https://www.iso-ne.com/static-assets/documents/2020/02/2020_smd_monthly.xlsx.

[79] Note that this comparative analysis does not distinguish between shifts in system demand (e.g., commercial versus residential air conditioning).

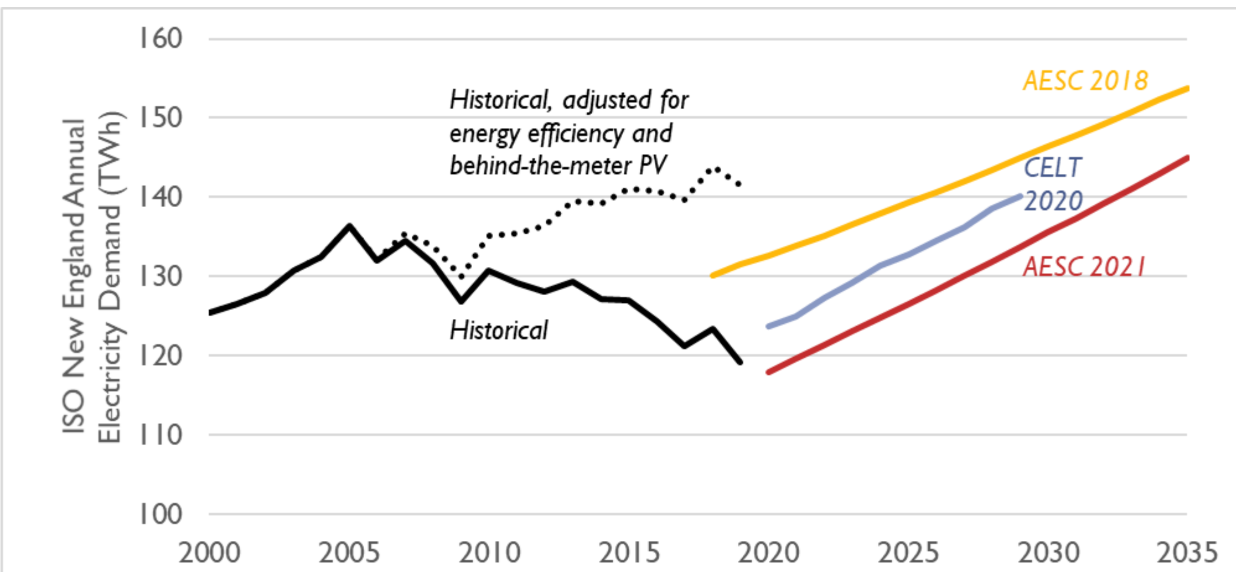
[80] Note that the regionwide CAGR calculated for gross demand in each of the CELT forecasts from CELT 2015 to CELT 2019 have ranged from 0.9 percent to 1.1 percent.

Figure 13. Actual versus projected system demand for 2020, ISO New England



Notes: All trajectories are inclusive of the effects of energy efficiency, BTM solar, and electrification.

Figure 14. Historical and projected annual energy forecasts for all of ISO New England



Notes: In both the "CELT 2020" and "AESC 2021" trajectories, all data points are decreased to reflect the energy efficiency installed in 2020 (see following section on "Programmatic Energy Efficiency"). No other impacts from energy efficiency, active demand management, building electrification, transportation electrification, or distributed solar are included.

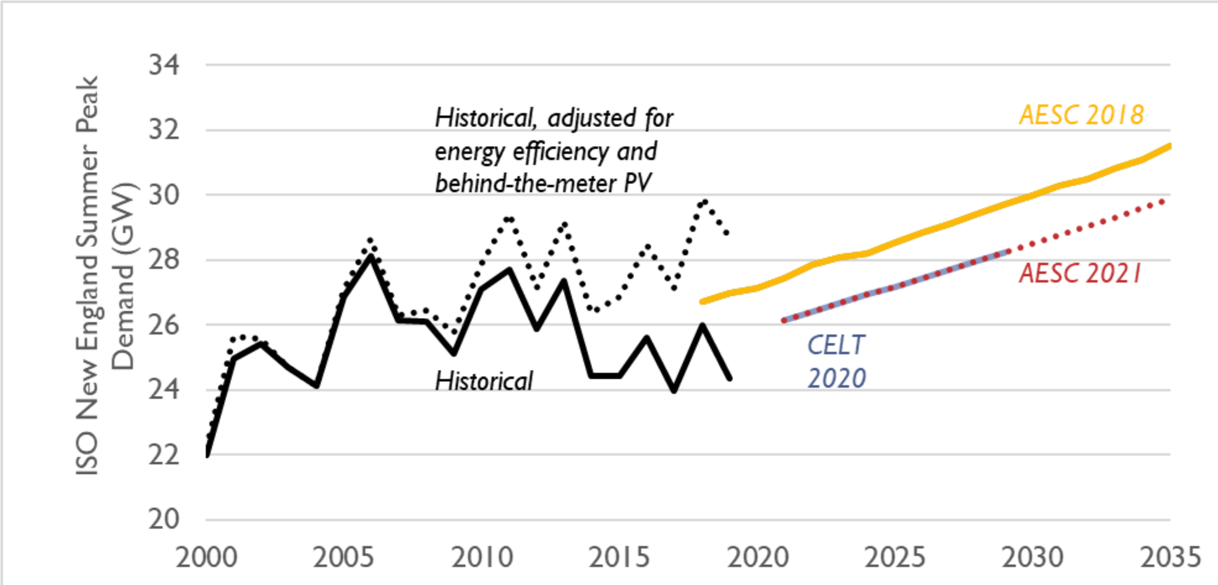
In order to develop hourly system energy demand, we apply hourly load shapes developed for each load zone published by ISO New England in the 2020 CELT study.[81] Note that while it is possible that load shapes may change over time, the scale and shape of these changes are uncertain. As a result, we rely on ISO New England's load shapes for purposes of simplification. Load shapes for other components of system load (e.g., energy efficiency, transportation electrification) are discussed in the *Other System Demand Components* section, below.

Peak demand forecasts and capacity requirements

To calculate peak demand, we compare projected summer peak demand from CELT 2020 with actual historical data. Per CELT 2020, the projected 50/50 net summer peak for ISO New England in 2020 (inclusive of impacts from energy efficiency, distributed solar, building electrification, and transportation electrification) was 25,125 MW. Through July 2020, the actual observed system peak was 25,054 MW (about 0.3 percent lower than projected). Based on the available data, it appears as though the COVID-19 pandemic has not had a substantial impact on summer peak in New England. As a result, we rely on the gross summer peak as specified in CELT 2020 (see Figure 15).

[81] Hourly load shapes developed by ISO New England for the CELT 2020 forecast can be found on the ISO New England website at https://www.iso-ne.com/static-assets/documents/2020/04/hourly_sa_fcst_eei2020.txt.

Figure 15. Historical and projected summer peak demand forecasts for ISO New England

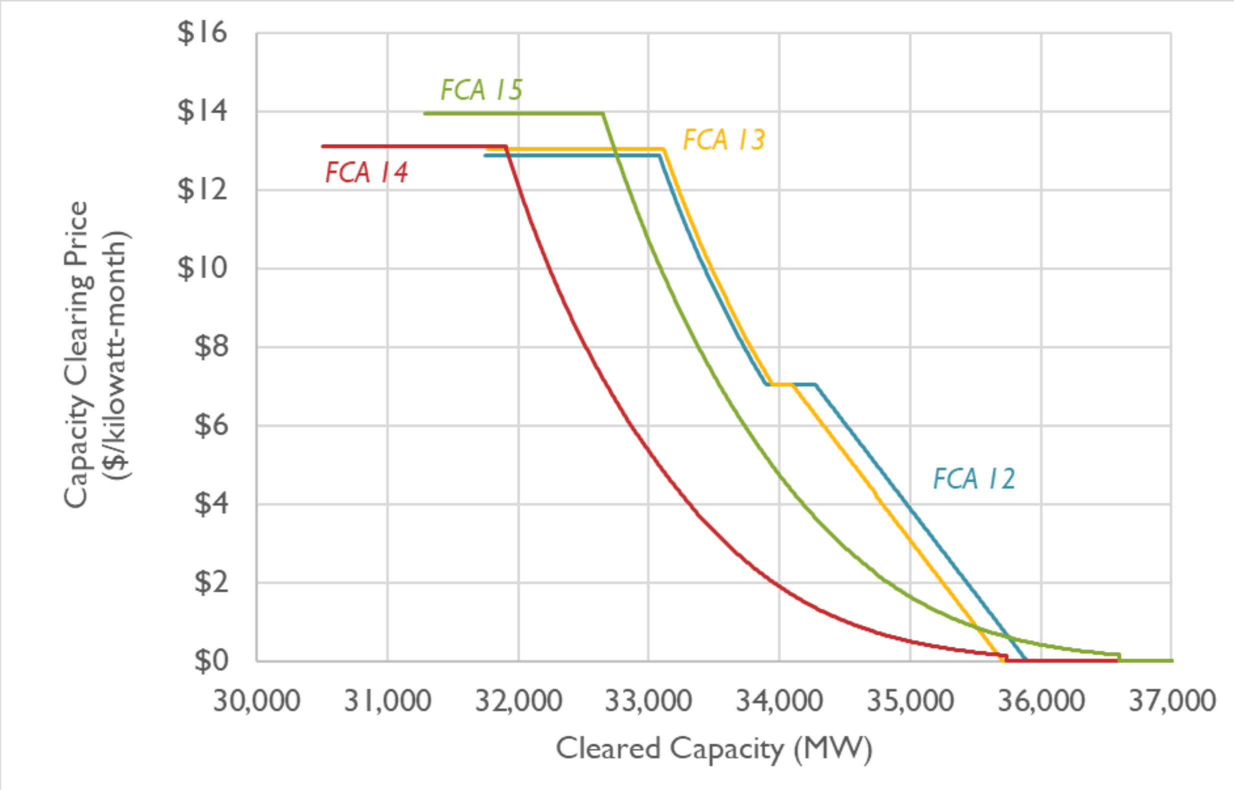


Note: The "AESC 2021" projection shown in this chart differs from the peak demand created in our EnCompass modeling as this value is calculated based on annual data available in ISO New England's CELT forecast, whereas the modeled values are calculated dynamically based on hourly, regional load shapes. For Counterfactual #1, this illustrative projection matches the modeled projection within +/-5 percent in all years.

The load forecast in one year is used in the forward capacity auction early in the next year to set the installed-capacity requirement for the capacity period starting three years after that. For example, the peak forecast for the summer of 2021 (released in May 2020) will be used to set the installed-capacity requirement for FCA 15 (held in February 2021) which sets the capacity obligations and prices for the period June 2024 to May 2025.

The actual capacity requirement is determined by the intersection of the supply curve (determined by resource bids) and a sloped "demand curve" set by ISO New England. Figure 16 shows the demand curve used in FCAs 12 through 15. ISO New England has transitioned from demand curves that partly followed the marginal reliability index (MRI) and were partially linear, with a flat part in between, to all-MRI curves in FCA 14 and 15.

Figure 16. Sloped demand curves, FCAs 11 to 15



Other system demand components

The following sections describe our other modifications to system demand. Some of these components are incorporated in all AESC 2021 counterfactual scenarios, while other components may only be used in a single counterfactual.

Programmatic energy efficiency

Since 2008, ISO New England has sought to compensate for these "embedded energy efficiency" effects by explicitly accounting for "passive demand resources" (PDR).[82] Thus, programmatic energy efficiency is excluded from the main ISO New England econometric forecasts, producing a "gross" forecast for annual energy and peak demand that is higher than it would be without the impact of PDRs. Starting in 2008, ISO New England has put forth a separate PDR forecast for energy efficiency resources, and since 2015, it has published a third forecast for distributed solar (PV). ISO New England then subtracts the forecasted quantities of PDRs and distributed PV from its gross forecast to estimate a "net" forecast, a lower number that reflects the actual estimated demand for each modeled year.

[82] Prior to 2008, ISO New England's forecast implicitly contained some level of reductions from efficiency programs because the programs were in effect during the historical period.

During the development of each CELT forecast, ISO New England works with the Energy Efficiency Forecast Working Group (EEFWG), which produces an estimate for future energy efficiency based on expected future energy efficiency expenditures and program performance. ISO New England estimates future energy efficiency impacts first based on levels of capacity that have cleared in the FCM, and then on future estimated levels of resource addition and attrition. Like other components of the 2020 CELT forecast, this forecast contains estimates of energy efficiency through 2029.

For an energy efficiency trajectory in AESC 2021, we rely on a modified version of the energy efficiency forecast described in CELT 2020. [83] This modified forecast includes three major differences relative to CELT 2020:

- First, this forecast removes the use of ISO New England's production cost escalator, which causes costs-per-MWh of energy efficiency to be roughly 10 percent larger in 2029 than in 2021. The Study Group requested this escalator be removed in order to develop a forecast that is more consistent with the program administrators' internal energy efficiency plans.
- Second, this forecast assumes that all energy efficiency budgets assumed by ISO New England for 2029 remain constant through 2035. This forecast also assumes that all end-use shares for energy efficiency measures (i.e., how much of a state's energy efficiency budget is dedicated to HVAC, or lighting, or other measures) remains constant from 2029 through 2035.
- Third, this forecast utilizes an energy efficiency forecast for Vermont provided by Vermont Department of Public Service, rather than the ISO New England forecast for energy efficiency in Vermont developed in the above steps.

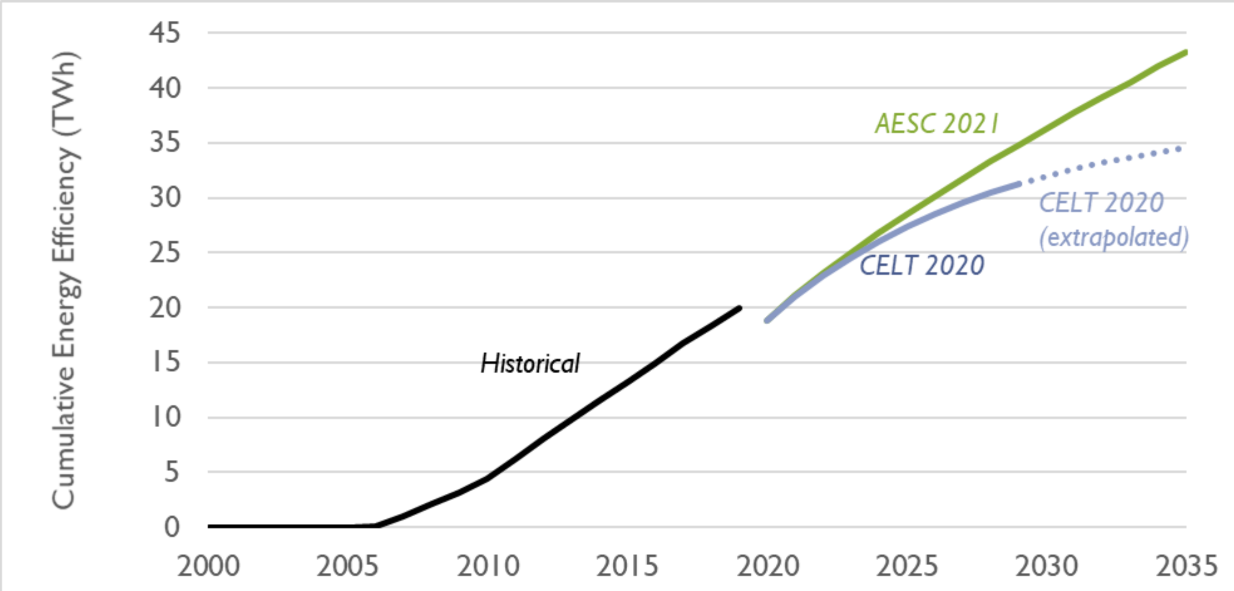
Figure 17 illustrates the difference in this modified forecast relative to the energy efficiency forecast provided in CELT 2020.

Generally speaking, past AESC studies have not considered scenarios that include forward-going levels of energy efficiency. This is the case in AESC 2021 for Counterfactual #1 and Counterfactual #3.[84] However, Counterfactual #2 requires a projection of energy efficiency.

[83] Another alternative considered by the Synapse Team would have extended recent historical levels of incremental savings through 2035. This forecast produced cumulative savings that were 15–20 percent higher than the CELT 2020 forecast through 2025, with greater differences in savings in later years.

[84] Note that, as in AESC 2018 but unlike AESC 2015, we do not decrease demand in future years to reflect energy efficiency for which program administrators are financially committed, but have not yet delivered (i.e., resources with capacity supply obligations in the 8th Forward Capacity Auction and later years, See AESC 2015, pages 5–14). Although these resources do have a financial commitment to be implemented, we believe that embedding them in the load forecast would prohibit users of the AESC 2021 from evaluating these resources' cost-effectiveness because of double-counting.

Figure 17. Historical and projected cumulative regionwide energy efficiency impacts used in Counterfactual #2



For Counterfactual #2, Synapse uses the same load shape for energy efficiency that is used for the econometric component of the energy forecast. This will effectively reduce the econometric component in every hour by the fraction of modeled energy efficiency (in MWh) relative to the system demand. While in reality, different energy efficiency measures have different load profiles, this simplified approach is meant to approximate the implementation of a portfolio of energy efficiency measures. Peak impacts of energy efficiency, and energy efficiency's contribution to the capacity requirement, will be determined by estimating the peak hour for energy efficiency in each year, based on the annual regionwide energy efficiency amount and annual system demand impact.

Active demand management

For the purposes of AESC 2021, active demand management includes both demand response measures as well as BTM energy storage measures. We modeled both resources as supply-side resources in the EnCompass model. Impacts of both types of resources are applied to peak demand calculations in the relevant counterfactuals.

This component is included in the modeling of Counterfactual #2 and Counterfactual #3, but not Counterfactual #1.

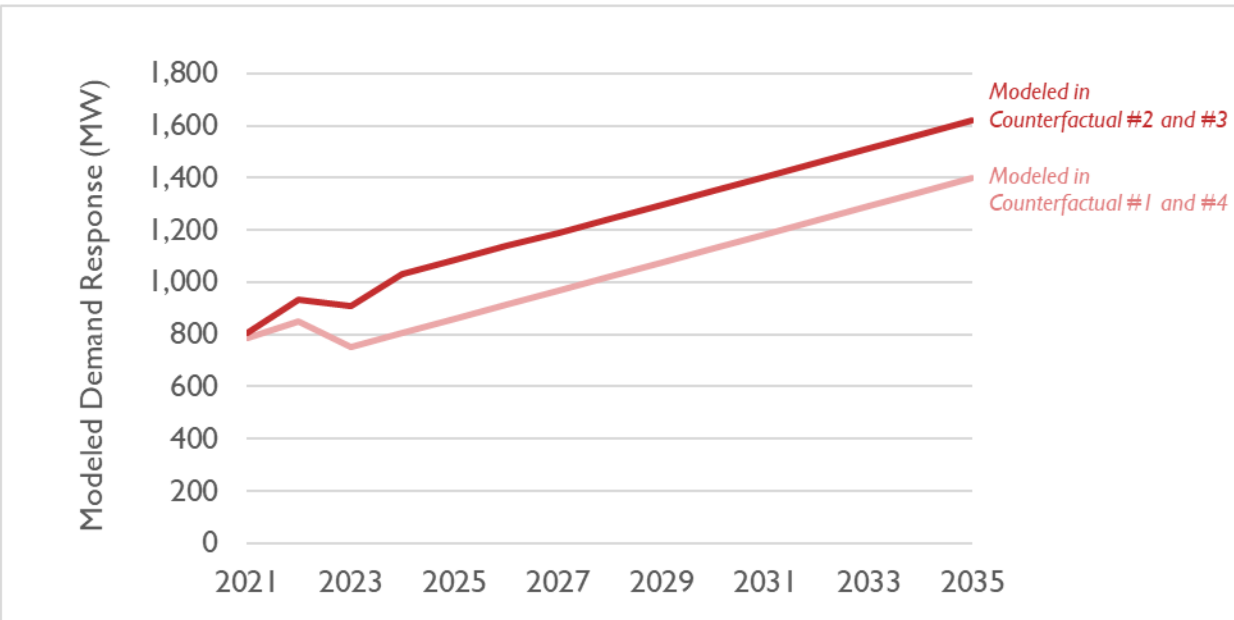
<u>Demand Response</u>

Demand response participates in ISO New England's FCM and serves as a peak demand resource. Demand response participation in the FCM has grown steadily for several years. To forecast demand response impacts in future years, we have extended the trend observed between capacity compliance periods between the summers of 2019 and 2023 linearly through 2035 (see Figure 18). In FCA 14, 592 MW of demand response capacity cleared the market and received a capacity supply obligation. We assume that all demand response that has cleared in the FCM so far is non-programmatic and is modeled in all counterfactuals.

In addition, we assume that under the current draft planning numbers for demand response Massachusetts is planning to install roughly 160 MW of measures capable of demand response in 2020 and perhaps double that quantity by 2024. This is the programmatic quantity assumed to be modeled in Counterfactual #2 and Counterfactual #3.

Based on recent historical behavior in the energy market, we assume that 10 percent of the entire demand response resource dispatches when prices are greater than $30 per MWh (in 2019 dollars) while 90 percent of this resource dispatches when prices exceed $900 per MWh (e.g., a stand-in for rare, very high price events).

Figure 18. Demand response forecast for New England



<u>Energy Storage</u>

There is currently no regional projection of BTM storage for New England. Furthermore, there is no data on existing BTM installations publicly available, although this data may be available to individual utilities. To establish a baseline of existing and projected BTM storage installation in New England, we have assembled data and projections from policy mandates and incentives for BTM storage for every state and New England. We then aggregated these projections to forecast total BTM storage capacity through 2035.

- Connecticut: In Connecticut, Eversource administers the Connected Solutions program which provides residential customers incentives for supplying their own batteries.[85] Under this program, customers can receive incentive payments of up to $225 per average kW used from their demand response resources over a three-hour period in certain seasons. The program supports only three battery vendors, including Sonnen, Generac, and Tesla.

- Maine: In December 2019, the Maine PUC was tasked with considering "bring your own device" (BYOD) programs for BTM energy storage in the state.[86] While there is no official BTM storage target or policy incentive, movement on this topic is forthcoming.

- Massachusetts: The first major incentive for storage is an adder as part of the Solar Massachusetts Renewable Target (SMART) program. As of February 2021, this program had approved about 40 MW of BTM storage in Massachusetts.[87] In April 2020, the state doubled the program target for solar from 16 GW to 32 GW. Though there is no specific target for BTM storage in this expansion; for the purposes of AESC 2021, we assume the capacity for BTM is doubled to reflect this update.

  Second, as in Connecticut, Eversource and National Grid deploy the Connected Solutions program through Mass Save, which provides residential customers an incentive for supplying their own batteries.[88, 89]

  Third, there are other programmatic BTM storage initiatives currently ongoing in Massachusetts, including the Daily Dispatch program and the Cape and Vineyard Electrification Offering (CVEO) program.[90] However, data on expected projections of BTM storage was not available at the time of our analysis.

[85] Eversource. Accessed March 10,2021. *Program Materials for Connected Solutions for Commercial/Industrial Customers*. Available at https://www.eversource.com/content/docs/default-source/save-money-energy/program-materials-demand-response.pdf?sfvrsn=695bd362_0.

[86] Maine 127th Legislature. December 2019. "Commissions to Study the Economic, Environmental and Energy Benefits of Energy Storage to the Maine Electricity Industry." Available at: https://legislature.maine.gov/doc/3710.

[87] Massachusetts Department of Energy Resources (DOER). "SMART Qualified Units." Accessed February 5, 2021. Available at: https://www.mass.gov/doc/smart-qualified-units-0.

[88] MassSave. Last Accessed March 10,2021. "Use Your Battery Storage Device to Make the Grid More Sustainable." *Massave.com.* Available at https://www.masssave.com/saving/residential-rebates/connectedsolutions-batteries.

[89] Members of the Study Group provided information on recently installed measures in Massachusetts' Connected Solutions program. For purposes of simplification and to avoid double-counting, we assume that all measures in this program are either also participating as demand response in the FCM or in the SMART program and are already accounted for in either one of the two projections.

Mass Save. February 11, 2020. *Energy Efficiency Program Administrators Quarterly Report*. Available at https://ma-eeac.org/wp-content/uploads/Quarterly-Report-of-the-PAs-2019-Q4-2-11-20-1.pdf.

Mass Save. August 12, 2020. *Massachusetts Energy Efficiency Program Administrators Quarterly Report.* Available at https://ma-eeac.org/wp-content/uploads/Quarterly-Report-of-the-PAs-2020-Q2-Final.pdf.

[90] Winter, D. March 16, 2016. *D.P.U. 20-33 – Fitchburg Gas and Electric Company d/b/a Until (Electric Division)*. Keegan Werlin LLP prepared for Department of Public Utilities. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11942570.

Finally, the newly launched Clean Peak Standard (CPS) may also serve as an incentive for BTM storage in the state. The CPS went into effect in June 2020. Qualified resources under the CPS include new renewable resources that also meet eligibility under Massachusetts' Class I and Class II RPS program.[91] Existing renewable resources in both programs are eligible, so long as these resources are paired with a new energy storage system. Furthermore, both standalone energy storage systems and demand response resources are eligible to meet the CPS. Modeling published by Massachusetts Department of Energy Resources describes the estimated benefits under the CPS, which are projected to reach over 120,000 metric tons by 2030.[92] Assuming that all of these benefits are provided by BTM storage, and that storage is able to provide a benefit of 60 metric tons per MW, this implies a 2030 capacity of about 2.0 GW.[93] This is substantially larger than the Commonwealth's current storage target of 500 MW in 2025.[94]

Based on recommendations from the AESC Study Group, we assume an exogenous 500 MW of storage in Massachusetts in 2025 and all later years.[95] Of this quantity, we assume that 70 percent is funded through the current energy efficiency programs, due to the size of the incentives offered in that program versus others (e.g., SMART, CPS). This 350 MW is the programmatic portion of storage assumed in Massachusetts. The remaining 150 MW non-programmatic portion is met through other programs, including SMART and CPS.

- New Hampshire: The New Hampshire Public Utilities Commission (PUC) is currently examining whether and how BTM storage can or should be incentivized. In January 2019, the NH PUC approved a BTM pilot project for Liberty Utilities' customers. Liberty partnered with Tesla to install 500 Tesla Powerwall batteries and 500 other private company batteries (totaling 1,000 BTM batteries) to be used for demand response.[96]

[91] Massachusetts Department of Energy Resources. October 26, 2020. *Clean Peak Energy Resource Eligibility Guide.* Available at https://www.mass.gov/doc/clean-peak-resource-eligibility-guidelines/download.

[92] Massachusetts Department of Energy Resources. August 7, 2019. *The Clean Peak Energy Standard.* Available at https://www.mass.gov/doc/drafts-cps-reg-summary-presentation/download . Slide 39.

[93] Per members of the Study Group, this metric tons per MW value is the avoided emissions value that has been applied for use in discussions regarding CPS.

State of Charge. 2017. *Massachusetts Energy Storage Initiative Study.* Prepared for Massachusetts Department of Energy Resources. Available at https://www.mass.gov/files/2017-07/state-of-charge-report.pdf. P. 95

[94] Massachusetts' energy storage goal is 1,000 MWh of storage by 2025 Per data available from *the* SMART program, the average duration of storage installed to date is 2 hours, which yields a storage target of 500 MW.

Massachusetts Department of Energy Resources. Last accessed March 11, 2021. "ESI Goals & Storage Target." *Massgov.com*. Available at https://www.mass.gov/info-details/esi-goals-storage-target.

[95] We note that the model is "allowed" to build more storage if it is economic to do so in any of the counterfactuals, states, or years. See Section 4.5: *Anticipated non-renewable resource additions and retirements* for more information on the assumptions used for this endogenous storage resource.

[96] Gheorghiu, Iulia. 2019. "Designing Liberty Utilities' New Hampshire residential storage program." *Green Tech Media (GTM)*. Available at: https://www.utilitydive.com/news/designing-liberty-utilities-new-hampshire-residential-storage-program/548940/

This program will put an estimated 5 MW of BTM storage in New Hampshire.[97] The program estimates roughly 100 batteries, equivalent to 500 kW of battery storage, will become operational per year.[98]

- Rhode Island: As in Massachusetts and Connecticut, National Grid administers the Connected Solutions program which provides residential customers incentives for supplying their own batteries.[99]
- Vermont: The main service provider for the state of Vermont, Green Mountain Power (GMP), has partnered with Tesla to pilot a BTM storage program for the state. This program, coupled with a provision that allows customers to "bring your own device" (BYOD), has incentivized between 13 and 14 MW of BTM storage installed in the state in 2019.[100] The program has been expanded and is projected to add up to 5 MW per year for the next 15 years.

The storage forecast from 2019 through 2035 for the entire New England region is shown in Figure 19.

[97] State of New Hampshire Public Utility Commission. Order No. 26,209. January 2019. Available at: https://www.clf.org/wp-content/uploads/2019/01/26-209.pdf

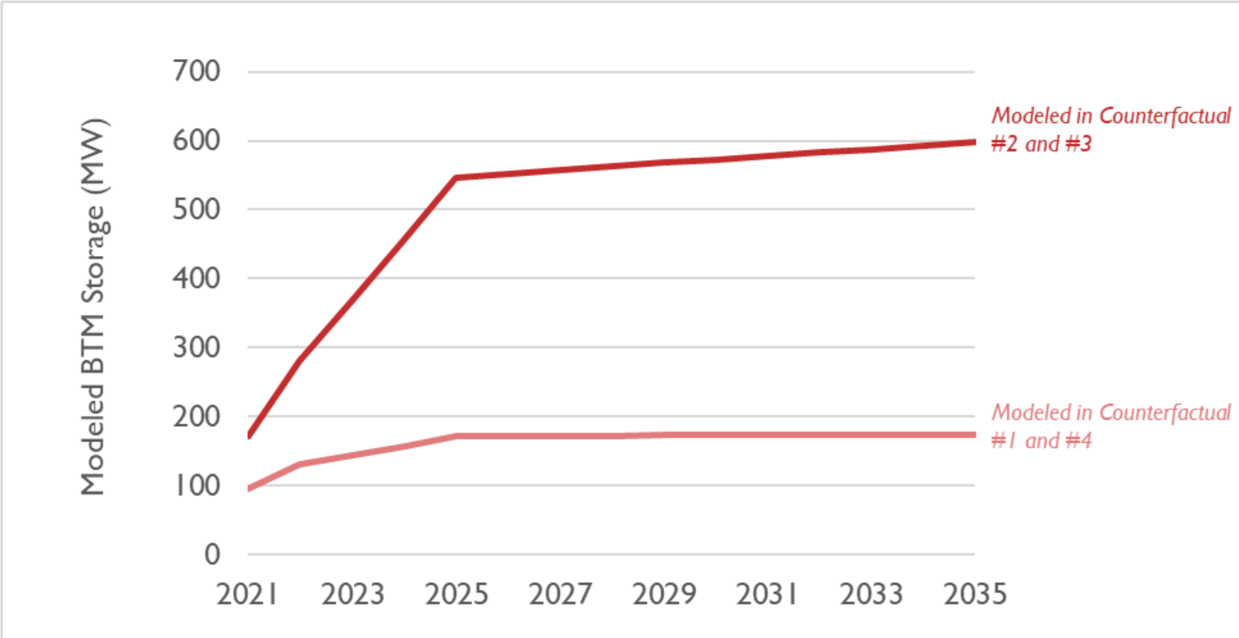
[98] Members of the Study Group provided information on recently installed measures in New Hampshire's C&I Active Demand Response Program. This includes 7.5 MW of existing capacity. However, demand response and BTM storage programs are not differentiated in this document. For purposes of simplification and to avoid double-counting, we assume that all measures in this program are accounted for in the demand response projection described in the section above (see Figure 18).

New Hampshire's Electric and Natural Gas Utilities. January 15, 2020. *New Hampshire Statewide Energy Efficiency Plan 2020 Update.* Prepared for NH Saves. Available at https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2020-01-15_EVERSOURCE_UPDATED_EE_PLAN.PDF.

[99] National Grid. Accessed August 27, 2020. "Use Your Battery Device to Make the Grid More Sustainable." National Grid website. Available at: https://www.nationalgridus.com/RI-Home/ConnectedSolutions/BatteryProgram.

[100] Gheorghiu, Iulia. 2020. "Green Mountain Power expands PYOD and Tesla battery programs as it targets fossil peakers." *Utility Dive.* Available at: https://www.utilitydive.com/news/green-mountain-power-to-roll-out-byod-and-tesla-battery-programs-as-it-targ/578573/.

Figure 19. BTM storage forecast for New England



Our modeling uses the same battery dispatch profile for all BTM storage in New England. Given the predominance of the CPS in this forecast, we assume that storage will dispatch according to the CPS seasonal peak periods: Winter (December 1 through February 28) 4 p.m. to 8 p.m., Spring (March 1 through May 14) 5 p.m. to 9 p.m., Summer (May 15 through September 14) 3 p.m. to 7 p.m. and Fall (September 15 through November 30) 4 p.m. to 8 p.m.[101] Under the CPS, systems may only get CPS credits for discharging within these daily hours of hours per day, so we assume each system is limited to discharging once per day (or 365 cycles per year).

Our BTM storage modeling assumes a round trip efficiency (RTE) of 85 percent for all storage systems as is consistent with field tests of battery storage performance.[102] We calculate MWh from capacity assuming a 2-hour duration.

Given the lack of data on BTM storage projections, it is challenging to determine what portion of the above programs might be deployed as part of an active demand management program managed by one of the AESC 2021 Sponsors, and what portion may be deployed regardless of actions taken by the AESC 2021 Sponsors. Table 25 describes what category each of the above programs appears to fall into. For the purposes of AESC 2021, we assume that only policies marked as "Programmatic" are programmatic; all other policies are modeled in all counterfactuals.

[101] Massachusetts Department of Energy Resources (DOER). August 7, 2019. *The Clean Peak Energy Standard.* Available at https://www.mass.gov/doc/drafts-cps-reg-summary-presentation/download. Slides 15 and 19.

[102] Deline, Chris, et al. July 2019. *Field-Aging Test Bed for Behind-the-Meter PV + Energy Storage*. National Renewable Energy Laboratory (NREL). Available at: https://www.nrel.gov/docs/fy19osti/74003.pdf.

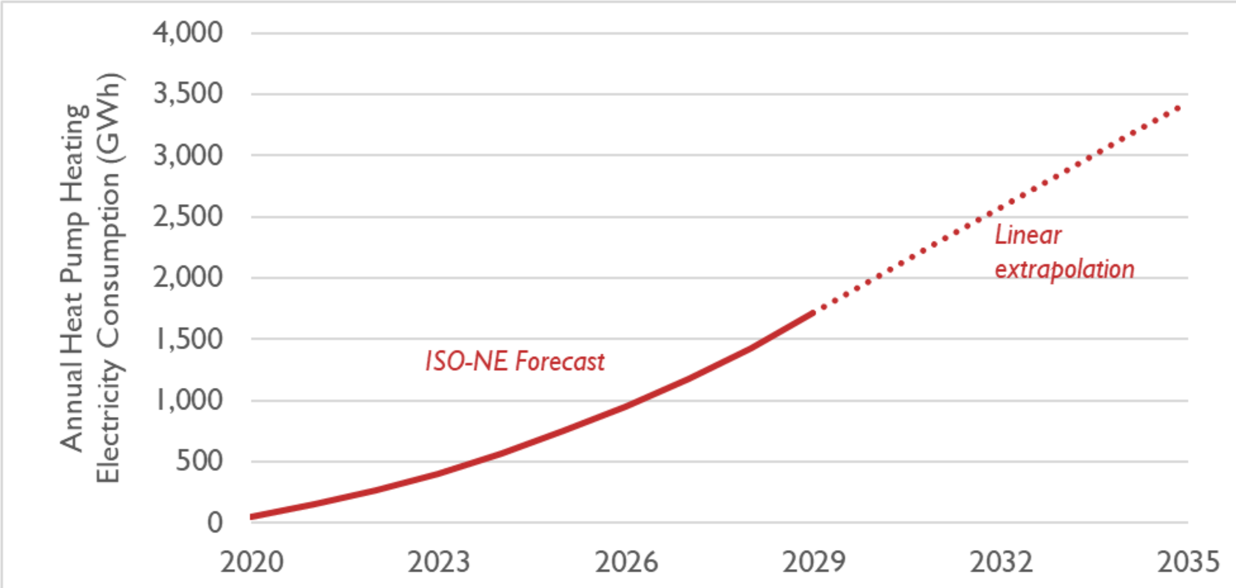
Table 25. Behind-the-meter storage categorization

State	Policy	Categorization
CT	Connected Solutions	**Programmatic**. Program entirely administered by Eversource; no data available
ME	*No known BTM storage policies*	-
MA	SMART program	**Unclear.** Project may overlap with other Massachusetts BTM storage policies. Measures assumed to be counted in the CPS program.
MA	Clean Peak Standard	**Unclear.** Project may overlap with other Massachusetts BTM storage policies.
MA	Connected Solutions	**Programmatic**. Program entirely administered by National Grid but assumed to be counted within the CPS program
MA	Daily Dispatch	**Programmatic**. Program entirely administered by PAs
MA	CVEO	**Programmatic**. Program entirely administered by CLC; no data available
NH	BTM Pilot (Liberty)	**Programmatic**. Program entirely administered by Liberty Utilities
RI	Connected Solutions	**Programmatic**. Program entirely administered by National Grid; no data available
VT	BTM Pilot (GMP)	**Programmatic**. Program entirely administered by Green Mountain Power

Building electrification

The adoption of electric air source heat pumps is projected to be a significant source of load growth over the study period, in certain counterfactuals. ISO New England developed a forecast of residential heat pump load as part of its CELT 2020 report to examine the winter electricity consumption of heat pumps (see Figure 20). ISO New England developed its forecast in collaboration with regional stakeholders who provided information about heat pump programs, incentives, and policy targets across the New England states. Heat pump adoption was modeled at the state level based on specific heat pump incentive programs.

Figure 20. Heat pump wholesale electricity impacts on heating for Counterfactual #3

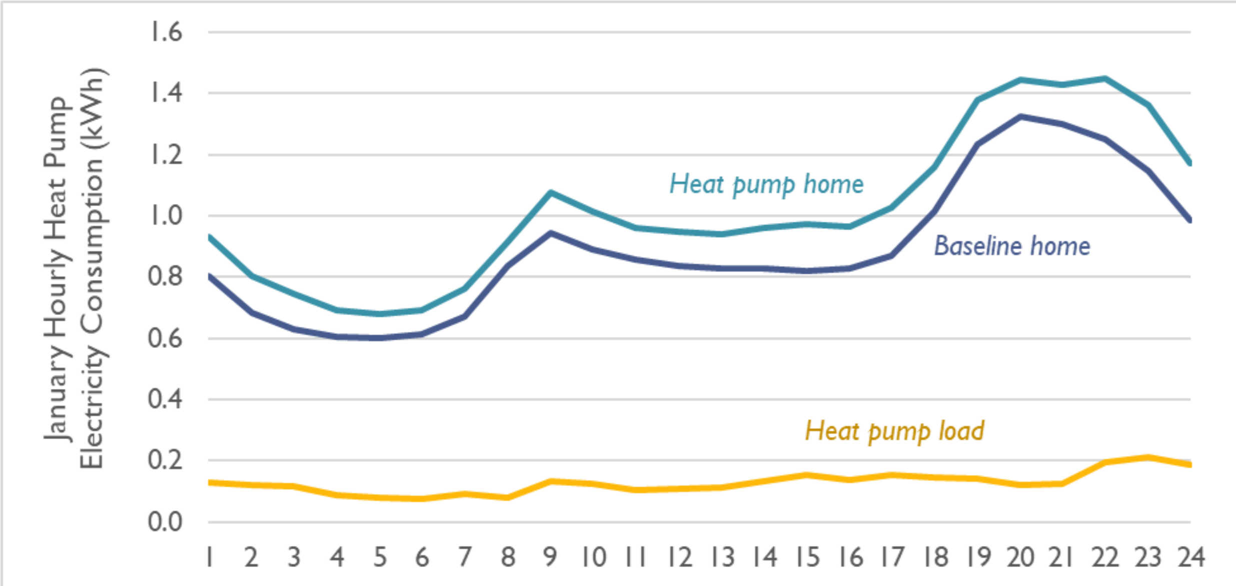


To develop hourly impacts, ISO New England combined its forecast for residential heat pump installations with advanced metering infrastructure load profile data for 18 residential heat pump installations in northeastern Massachusetts. ISO New England noted that this is a small sample size and that it may not be reflective of the entire region.[103] As more heat pumps are installed and additional studies become available, it is likely that this data will be refined. Currently, data availability for load profiles based on recent heat pump installations is limited.

ISO New England presented load shapes for homes with and without heat pumps in the advanced metering infrastructure data it acquired. This dataset included 33 homes with heat pumps and more than 400 homes without heat pumps. We calculated the hourly load profile of a heat pump by subtracting the baseline home load profile from a heat pump home load profile. The January load profiles (used for the winter season) are shown in Figure 21.

[103] ISO New England. 2019. "Draft 2020 Heating Electrification Forecast." *Load Forecast Committee.* Available at: https://www.iso-ne.com/committees/reliability/load-forecast/. Page 3.

Figure 21. Hourly heat pump load profiles for January



As in the CELT 2020 forecast, we assume that summer impacts of residential heat pump adoption will be small. As a result, we do not explicitly adjust summer loads. To inform this decision, we examined several different sources. First, a 2019 evaluation study of Connecticut heat pump installations reports the increased electricity loads resulting from heat pump installations in homes that previously lacked air conditioning, as well as the decreased electricity loads in homes that had central or window air conditioning prior to heat pumps.[104] The Connecticut study concludes (based on a weighted average of cooling systems prevalent in the state and average summer conditions) that heat pump installations summer savings are about 47 kWh per ton.

However, for several reasons, we believe that the expected long-term, New England-wide impact on cooling would be significantly smaller. First, some of the other New England states (particularly Vermont, New Hampshire, and Maine) would be expected to have lower penetrations of existing cooling systems and would therefore see more summer load growth and fewer cooling savings as a result of heat pump adoption. Second, the Connecticut study reports that heat pumps consume 26 percent as much electricity for cooling as they do for heating. Based on cooling and heating degree data for Massachusetts, we expect the long-term ratio of cooling to heating energy consumption to be significantly lower, as data for recent years suggests that the number of cooling degree days is only about 10 percent of the number of heating degree days.[105] This difference suggests that the heat pumps evaluated in the study may not have been sized to meet the full heating loads of the households, and

[104] DNV GL. June 20, 2019. *R1617 Connecticut Residential Ductless Heat Pumps Market Characterization Study – Final Report*. Available at: https://www.energizect.com/sites/default/files/R1617_CT%20Residential%20DHP%20Market%20Characterization%20Study_Final%20Report_6.20.19.pdf.

[105] Mass.gov. Accessed September 15, 2020. "Mass. Home Heating Profile Background." Available at: https://www.mass.gov/service-details/mass-home-heating-profile-background.

that incremental heat pump installations in these households (or future heat pumps installed without backup heating systems) would provide additional heat but not displace any additional cooling. Finally, heat pump energy savings in the summer may be included in the energy efficiency forecast, and thus not including additional savings here avoids potential double-counting. Additional data would improve the precision with which heat pump summer impacts could be quantified, but we believe these impacts are likely to be small and we have not quantified them in AESC 2021.

For the purposes of AESC 2021, all residential heat pump impacts are assumed to be programmatic.[106]

At this time, we do not have information to develop a forecast for other types of building electrification, including commercial or industrial heat pumps or variable refrigerant flow (VRF) systems, or other types of industrial electrification. The Study Group identified several studies that examine pilot programs aimed at these technology types in Massachusetts, Rhode Island, and Vermont; but projections that mirror the trajectories modeled for residential heat pumps, energy efficiency, and transportation electrification (for example) are currently unavailable.[107]

This component is included in the modeling of Counterfactual #1 and Counterfactual #3, but not Counterfactual #2. While some non-program heat pump adoption would be expected even in Counterfactual #2, we do not include any specific heat pump load forecast. ISO New England's general load forecast methodology includes a regression over historical load data that includes some amount of heat pump load. Thus, the general forecast implicitly includes a small amount of heat pump adoption, which is appropriate for a case in which no heat pump programs are implemented.

Transportation electrification

Over the study period of AESC 2021, vehicle electrification is projected to increase demand for electricity. In CELT 2020, ISO New England developed a forecast for electric vehicle (EV) electricity consumption as part of its CELT 2020 report. The CELT forecast uses a projection of the number of EVs sold in New England from AEO 2019. Among projections of EV adoption, AEO 2019 has one of the lowest forecasts, with EV sales projected to largely plateau after a limited increase in the 2020s. In place of this, Synapse has developed its own forecast to reflect the likelihood of continued growth in the EV market in the medium to long term. We use an EV sales forecast from Bloomberg New Energy Finance's (BNEF) *Electric Vehicle Outlook 2020*.[108] The Transportation and Climate Initiative's (TCI) reference case forecast was also considered, but ultimately not chosen due to its high short-term EV sales forecast, which is not

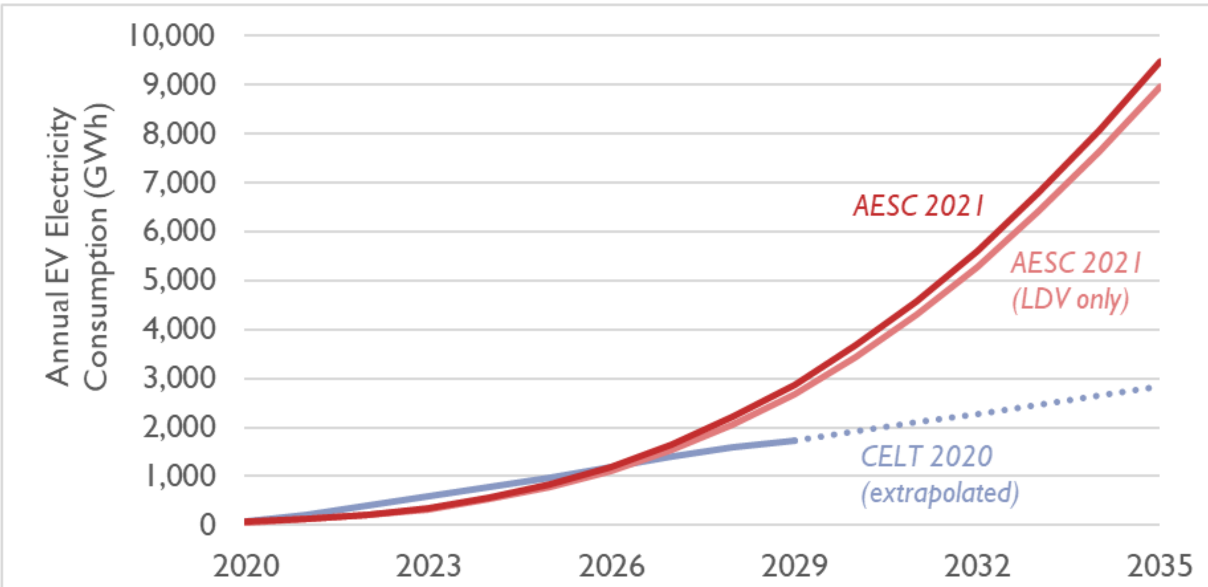
[106] Note that historically, a small amount of heat pump load growth has been implicitly projected in the CELT forecast through ISO New England's regression model.

[107] Synapse also examined deployment of commercial heat pumps in the 2020 edition of the AEO. According to underlying modeling data provided by EIA, commercial heat pumps currently make up less than 0.5 percent of New England's electricity demand; they are not projected to have any change in electricity consumption between 2018 and 2040, under the baseline conditions modeled in the 2020 AEO Reference case.

[108] Bloomberg New Energy Finance. 2020. *Electric Vehicle Outlook 2020*. Available at: https://about.bnef.com/electric-vehicle-outlook/.

in line with the most recent sales data.[109, 110, 111] Both the BNEF and TCI forecasts show similar levels of EV sales in the medium to long term. The Synapse forecast uses the Electric Vehicle Regional Emissions and Demand Impacts (EV-REDI) model to evaluate how long EVs remain on the road, how many miles EVs are driven, and how much electricity they consume.[112] One advantage of this methodology is that it eliminates the need to extrapolate the CELT forecast beyond 2029. We also use BNEF's global forecast for medium- and heavy-duty vehicle electrification to project electrification load associated with medium- and heavy-duty trucks (including buses). The CELT and Synapse load forecasts are shown in Figure 22 and peak demand impacts are shown in Figure 24.

Figure 22. Projected wholesale electricity consumption from EVs in ISO New England for all Counterfactuals



CELT 2020 also includes an hourly EV charging profile based on data acquired from the EV charging station company ChargePoint. This dataset includes a sample of charges located at both residential and commercial locations. ISO New England narrowed the dataset to include a greater fraction of residential charging, reflecting ISO New England's view that most EV charging occurs at homes. The CELT 2020 daily charging profiles are shown in Figure 23. These same EV load profiles are also used in the AESC 2021

[109] Transportation and Climate Initiative. August 8, 2019. Reference Case Results Webinar. Available at: https://www.transportationandclimate.org/sites/default/files/20190808%20-%20TCI%20Webinar%20-%20Reference%20Case%20Results.pdf.

[110] TCI is a regional collaboration of 12 states and the District of Columbia to improve clean transportation. Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. States will choose individually whether to adopt the final proposed policy framework.

[111] Note that we have used BNEF's forecast for passenger vehicles to forecast EV adoption for all light-duty vehicles, which includes both passenger vehicles and light commercial vehicles.

[112] See Synapse's website at https://synapse-energy.com/tools/electric-vehicle-regional-emissions-and-demand-impacts-tool-ev-redi for more information on the EV-REDI model.

Study for both light-duty vehicles (LDV) and medium- and heavy-duty (MHD) vehicles.[113] The summer peak impact resulting from this EV adoption and load shape is shown in Figure 24.

Figure 23. Seasonal, hourly EV load profiles assumed by ISO New England in CELT 2020

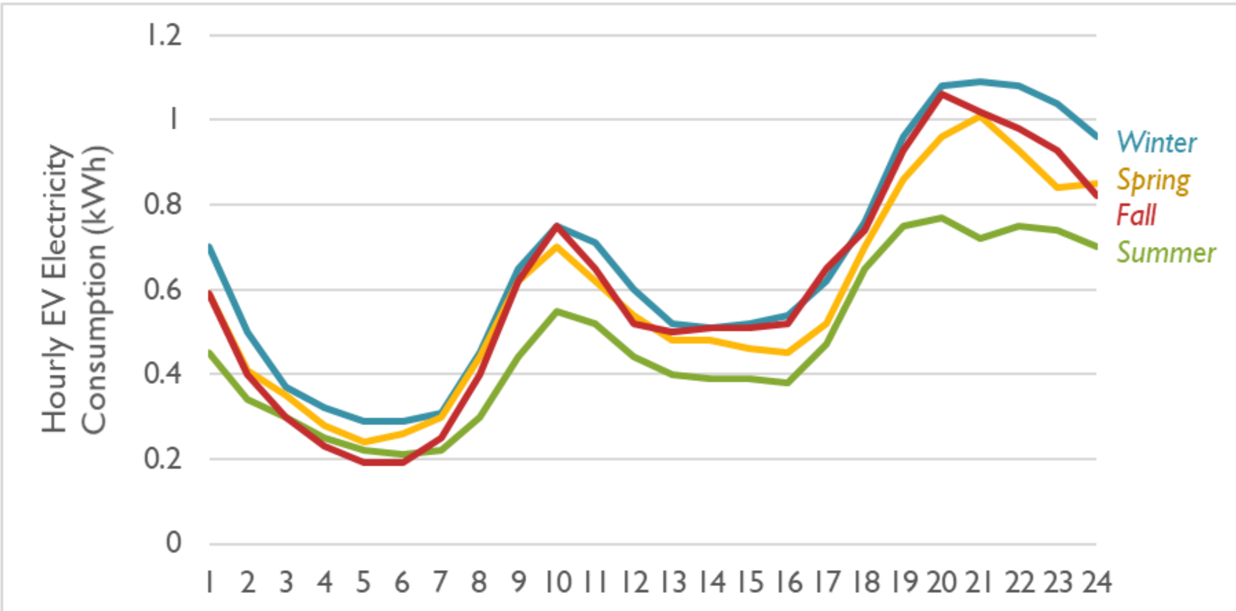
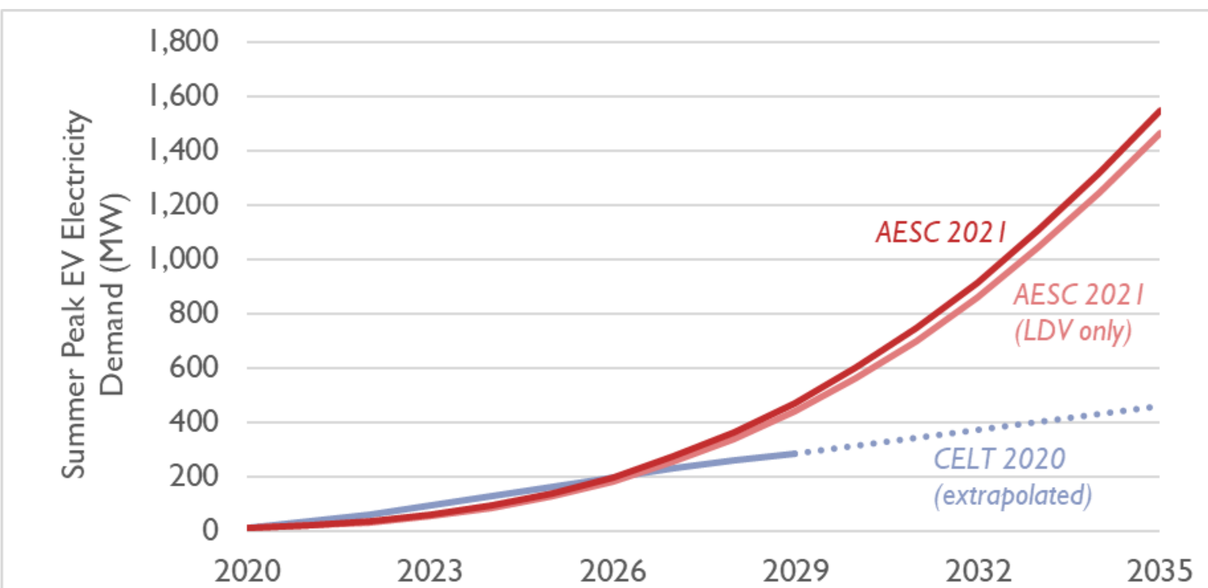


Figure 24. Summer EV wholesale peak demand impacts in ISO New England for all Counterfactuals



[113] In reality, MHD vehicles are likely to differ in terms of daily charging profiles. However, given the diversity of MHD end-uses and the early stage of MHD EV adoption, there is little data available for a reasonable alternative. Finally, since most EV charging load modeled in AESC 2021 is associated with LDVs, it is unlikely that a different charging profile would substantially impact avoided costs.

Importantly, the ChargePoint data represents how EV charging has occurred historically. As EV load grows, there will be greater benefits associated with implementing managed charging programs and shifting more charging to off-peak periods. Limited managed charging programs are currently in place in New England. While the ChargePoint data is the best available source for historical charging patterns, it may misrepresent future charging behavior and may overstate peak impacts.

While the COVID-19 pandemic has affected the LDV market during 2020, we do not anticipate significant medium- or long-term impacts to the rate of EV adoption, in line with recent projections from other analyses. For example, an August 2020 EV projection published by Wood Mackenzie suggests that the impact of the COVID-19 pandemic on mid- to long-term EV adoption is likely to be limited.[114] As a result, we have not explicitly adjusted the EV load forecast to account for the COVID-19 pandemic. However, the EV sales forecast described above does have short-term sales projections in agreement with the most recent sales data that has been released during the pandemic.

This component is included in all counterfactuals and does not differentiate between programmatic or non-programmatic components.

Distributed generation

For the purposes of AESC 2021, “distributed generation” is assumed to include only distributed solar. Like active demand management, distributed generation is modeled as a supply-side resource in the EnCompass model. Impacts from distributed generation is applied to peak demand calculations in each counterfactual.

The 2020 CELT forecast contains a projection of BTM solar. This forecast applies material discount factors (35 to 50 percent) to post-policy distributed PV installation to reflect uncertainty associated with future policies and/or market conditions. This approach, which yields lower PV load reductions than what may be realistic, is appropriate for reliable planning and operation of the system. For the purpose of the AESC 2021 study, we used a distributed PV forecast that is more representative of expected solar installation under existing policies and future policies (if applicable) and / or market conditions, based on research and market analysis. For more information on the Synapse Team’s methodology for modeling distributed solar, including policies modeled and load profiles, see Section 4.4: *Renewable energy* .

This component is included in all counterfactuals and does not differentiate between programmatic or non-programmatic components.

[114] Chandrasekaran, R. August 26, 2020. “Electric Vehicles Market to Get Back on Track Post-COVID-19.” *Wood MacKenzie*. Available at: https://www.woodmac.com/news/opinion/electric-vehicles-market-to-get-back-on-track-post-covid-19/.

Other resources not modeled in AESC 2021

There are other emerging DSM programs (see Table 26) that may be modeled using the 8,760 avoided cost values. These resources are not modeled in any AESC 2021 counterfactuals.

Table 26. Current status of emerging DSM technologies

Technology	Other Components or Considerations
Conservation Voltage Reduction (CVR)	The traditional avoided costs streams may be applied for CVR programs. CVR occurs in front of the customer meter. Some feeders, such as those with high motor load, may not be appropriate for CVR. CVR factors for feeders would need to be quantified. Utilities must maintain service quality requirements, which may limit applicability. Distribution planning personnel from program administrators should weigh in on the matter.
Volt-Var Control (VVO)	The traditional avoided costs streams may be applied for VVO programs. VVO occurs in front of the customer meter. Hourly data for real and reactive power will determine hourly line losses, and the difference between baseline and impact losses yields energy savings. Distribution planning personnel from program administrators should weigh in on the matter.

Energy losses

Electric systems incur energy losses when delivering power from power plants to customer's sites through T&D wires. T&D losses are developed in AESC 2021 for two main reasons:

- First, the development of certain categories of load forecast components requires the conversion between retail electricity consumption and wholesale electricity impacts. In this case, T&D losses are inputs into the avoided costs.
- Second, readers of AESC 2021 may wish to apply a T&D loss factor to convert the wholesale avoided costs calculated in AESC into retail avoided costs. In this case, T&D loss factors are applied to modeling outputs.

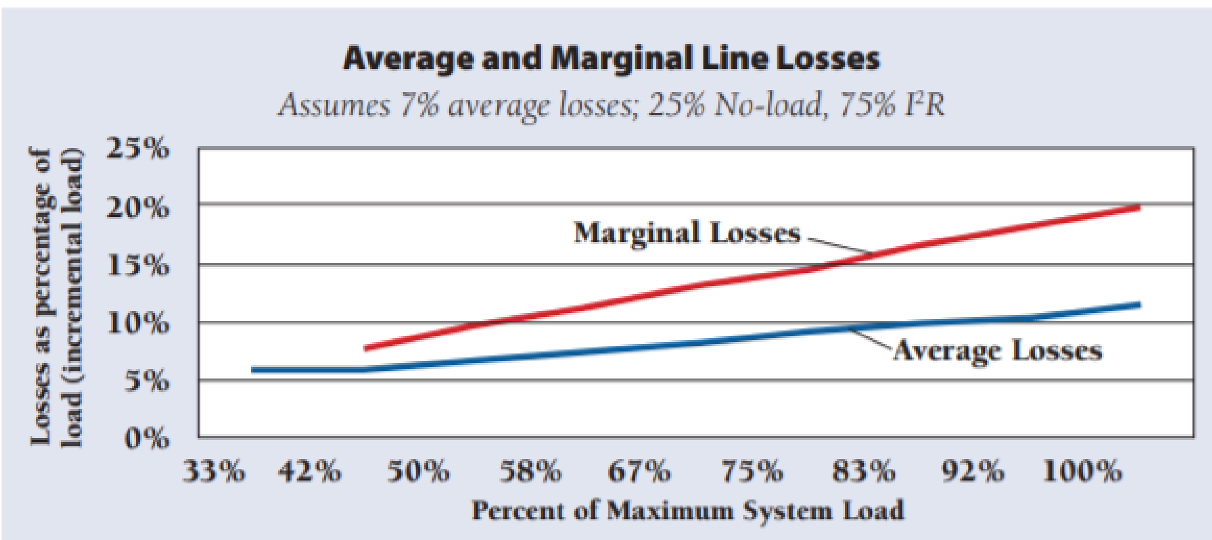
The following section is primarily concerned with the development of the T&D losses under the first category, as it is our understanding that each program administrator calculates and applies (or uses a T&D loss factor based on state precedent). However, readers may wish to review the following section to help inform their selection of loss factors.

Marginal loss factors

The amount of energy loss is affected by a number of factors including resistance in wires, system utilization rates, and weather conditions. Energy losses are generally higher when loads are higher and significantly higher during peak periods because resistive losses in wires increase with the square of the load (loss power = I^2R). This means that line losses for incremental loads ("marginal losses") that would be avoided by DSM programs are likely higher than average line losses. On the other hand, a certain amount of loss, ranging from 20 percent to 30 percent of the entire loss, are "no-load losses" that do not increase with the square of the current, unlike resistive losses. These losses incur to energize the system (i.e., create a voltage available to serve a load).[115] This means that the influence of resistive losses is greater at higher load levels because the impact of the no-load losses is fixed and relatively smaller at higher load levels.

A 2011 Regulatory Assistant Project (RAP) paper, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," discusses in detail line loss factors. This paper presents an example of line loss factors and demonstrates how marginal and average losses vary at different system load levels as shown in Figure 25. This figure shows that the increases in marginal losses are greater than the increases in average losses as the system load levels increase. For example, when the system is loaded at 50 percent of the capacity, average and marginal losses are approximately 6 percent and 8 percent respectively, and when the load is near its capacity, average and marginal losses are approximately 12 percent and 20 percent respectively.

Figure 25. Average and marginal line loss factors from Lazar and Baldwin (2011)



Source: Reproduced from Figure 4 in "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements." (2011) Regulatory Assistance Project (RAP). Available at https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

In order to accurately estimate annual average marginal losses, we need to know detailed load data and system utilization rates for each hour of a year. However, details on system utilization rates are not readily available for ISO New England. The RAP paper suggests a rule of thumb value that marginal losses are about 1.5 times average losses. Thus, we use a factor of 1.5 to convert annual average line losses to marginal line losses. This value is also the value recommended by some stakeholders including one local utility in New Jersey and recently adopted by New Jersey Board of Public Utilities for

[115] RAP. 2011. Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. Available at http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

establishing the New Jersey Cost Test.[116] In AESC 2021, we apply a marginal loss factor to any incremental load added in a given year; all other portions of the load (i.e., the quantity that is less than or equal to the total load in the previous year) utilize an average loss factor. We use an average loss factor of 6 percent and a marginal loss factor of 9 percent (calculated by multiplying 6 percent by 1.5).[117]

For estimating marginal losses associated with capacity, we would need to know the system utilization factor at peak hours, or in other words, the degree to which the T&D system is stressed. While the utilization rates at the peak hours are by definition higher than the average rate for an entire year, detailed data for system utilization rates for the entire ISO New England grid for peak hours is not readily available. Thus, we rely on a larger factor than used for annual energy. Based on the data in Figure 25, factors for marginal losses over average losses range from 1.4 at a 50 percent system utilization factor to 2.6 at a 92 percent system utilization factor. Based on this range, we rely on a simple factor of 2.0. For the purposes of calculating the wholesale impact of load components (see above), we apply a marginal loss factor of 16 percent (calculated by multiplying 8 percent by a factor of 2.0) and an average loss factor of 8 percent to any existing demand (e.g., the quantity of demand in a year that is equal to or less than the previous year's demand).[118]

For more on applying energy losses to wholesale avoided costs, see Appendix B: *Detailed Electric Outputs*.

4.4. Renewable energy assumptions

See Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* for more information on the assumptions used for renewable energy in AESC 2021's energy and capacity modeling. We describe additional assumptions on offshore wind interconnections below.

Offshore wind interconnection

The REMO Model provides information on projected offshore wind capacity and generation but does not specify where these facilities interconnect with New England's electric grid. We assume that all offshore wind that is built in southern New England is built in the U.S. Bureau of Ocean Energy Management's designated lease zones (see Figure 26). However, there is ongoing discussion on where these offshore wind facilities will interconnect. Options include locations on or near Cape Cod; New London or further west in Connecticut; Quonset, RI; Brayton Point, MA; or in the Greater Boston region.

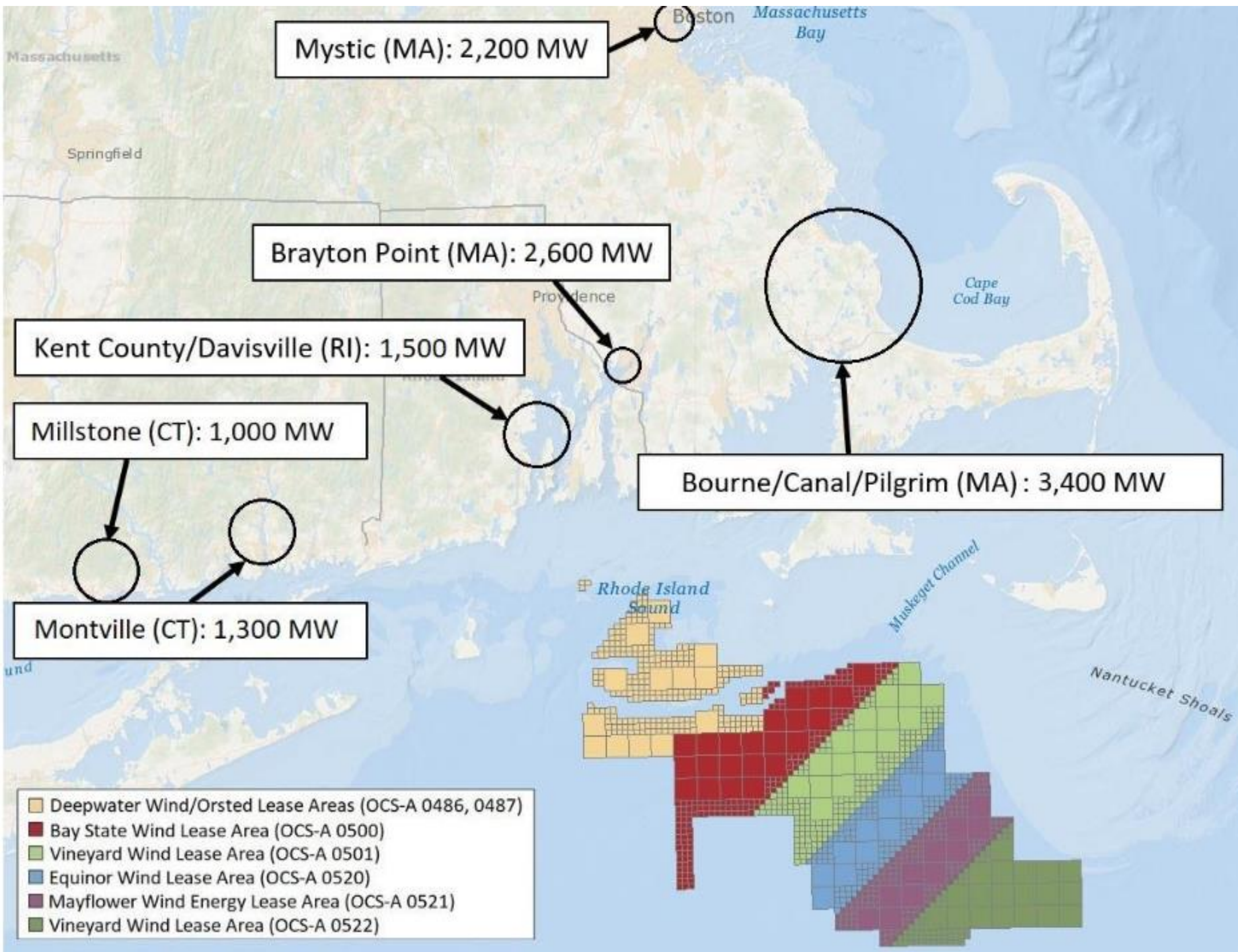
[116] New Jersey Board of Public Utilities. 2020. Order Adopting the First New Jersey Cost Test. Docket No. QO19010040 and QO20060389.

[117] Note that 6 percent is the average T&D loss factor assumed by ISO New England for long-term energy forecast. ISO New England. November 18, 2019. *Update on the 2020 Transportation Electrification Forecast.* Available at https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf.

[118] See ISO New England Market Rules, Section III.13.1.4.1.1.6.(a).

In order to minimize price anomalies, we distribute the offshore wind interconnection points throughout southern New England.[119] Although there is uncertainty about which interconnection points will be used, to what degree, and when, we rely on a simplified "cycling" methodology to allocate the offshore wind throughout various modeling zones. Using 800 MW blocks, we change the interconnection point of offshore wind projects as they are built, moving from Southeast Massachusetts, to Rhode Island, to Connecticut Northeast, to Boston, and back through again. By 2035, this produces interconnected quantities that are largely consistent with those described in two separate recent modeling studies by Anbaric and NESCOE.[120]

Figure 26. Bureau of Ocean Energy Management (BOEM) lease zones in southern New England and potential interconnection points



Source: Figure reproduced from https://www.iso-ne.com/static-assets/documents/2020/03/a8_anbaric_2019_economic_study_prelim_results_marpac.pdf, *slide 9.*

119 Through exploratory analysis in AESC 2021, we discovered that interconnecting all the offshore wind builds in the Southeast Massachusetts modeling zone produced very low energy prices in that zone and Rhode Island.

120 ISO New England. "Anbaric 2019 Economic Study – Offshore Wind Results." March 18, 2020. Available at https://www.iso-ne.com/static-assets/documents/2020/03/a8_anbaric_2019_economic_study_prelim_results_marpac.pdf. Page 51.

4.5. Anticipated non-renewable resource additions and retirements

The following section highlights key input assumptions regarding retirements of existing units as well as anticipated additions of new generating units. This section is not meant to be a comprehensive census of all existing generators; instead, it is meant to provide an overview of the significant changes to non-renewable capacity expected to occur during the analysis period.[121]

Nuclear units

There are two remaining nuclear plants in New England: Seabrook (located in New Hampshire) and Millstone (located in Connecticut). Seabrook has one unit, and Millstone has two (see Table 27). None of the three units have announced a retirement date within the AESC 2021 analysis period. In the recent past, the Nuclear Regulatory Commission (NRC) relicensed Pilgrim 1 (previously located in Massachusetts and retired in May 2019), Millstone 2, and Millstone 3—along with many other reactors outside New England—without denying a single extension.[122] Based on this track record and the lack of evidence suggesting that the NRC would deny license renewals for any of these plants, we assume that all three nuclear units continue to operate throughout the entire modeling period.[123]

Table 27. Nuclear unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Current License Expiration Date
Seabrook 1	NH	1,242.0	None	March 2050
Millstone 2	CT	909.9	None	July 2035
Millstone 3	CT	1,253.0	None	November 2045

We do not model any incremental nuclear unit additions during the study period.

Coal units

As of August 2020, there are three coal units operating in New England, spread across two power plants (see Table 28). Other recently retired plants include Brayton Point (retired June 2017), Mount Tom (retired June 2014), Salem Harbor (retired June 2014), and Schiller (retired July 2020).

[121] Note that we are not proposing to include any incremental demand response resources in our analysis, in line with our assumptions for conventional energy efficiency resources.

[122] NEI. Last accessed March 10.2021. "Nuclear Energy in the U.S." *Nei.org*. Available at https://www.nei.org/resources/statistics.

[123] These assumptions are consistent with those assumed by ISO New England in its 2019 Regional System Plan (see https://www.iso-ne.com/static-assets/documents/2019/10/rsp19_final.docx, page 152), with the addition of an assumed license extension for Seabrook 1.

Of the remaining units, Bridgeport Station 3 has already announced a retirement date. The Merrimack units have undergone substantial environmental retrofits in recent years. In this analysis, we make the below assumptions for these units' future operation.

Merrimack

The Merrimack power plant consists of two coal-fired units, and two 19-MW gas-fired combustion turbines. The two coal units at Merrimack were built in 1960 and 1968, making the units 52 and 60 years old, respectively, as of 2020. Both Merrimack coal units feature a wet fluidized gas desulphurization (FGD) system to control for SO_2, a selective catalytic reduction (SCR) system to control for NO_X, and an electrostatic precipitator (ESP) to control for particulate matter. Merrimack 1 operated at a capacity factor of 7 percent in 2019 and 2 percent in the first six months of 2020; Merrimack 2 operated at 8 percent and 3 percent in those same periods. All four Merrimack units have capacity commitments through FCA-14 (i.e., through May 31, 2024). Consistent with AESC 2018, we assume that both Merrimack 1 and Merrimack 2 retire on January 1, 2025, and that the other two (gas-fired) Merrimack units are operational throughout the analysis period.

Table 28. Coal unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Modeled Retirement Date
Bridgeport Station 3	CT	400.0	June 2021	June 2021
Merrimack 1	NH	113.6	None	January 2025
Merrimack 2	NH	345.6	None	January 2025

We do not model any incremental coal unit additions during the study period.

Natural gas and oil units

Throughout the study period, we assume over 40 MW of new capacity additions from natural gas or oil resources. Table 29 lists the units added exogenously during the study period. Data on capacities and online dates are from EIA's Form 860 and the FCM. These resources are assumed to be primarily natural gas-fired.

Table 29. Incremental natural gas and oil additions

Unit	State	Capacity (MW)	Modeled Online Date	Unit Type
MIT Central Utilities/Cogen Plant GT200	MA	21.7	Feb 2021	Combustion Turbine
MIT Central Utilities/Cogen Plant GT300	MA	21.7	Feb 2021	Combustion Turbine
Killingly	CT	632	Oct 2023	Combined Cycle

In addition, there are a number of major natural gas- and oil-fired units which are assumed to retire during the study period (see Table 30). Unit retirements are based on announcements by the unit owners. We do not assume any additional exogenous natural gas- or oil-fired unit retirements beyond those detailed in this table.

Table 30. Major natural gas and oil retirements

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type	Notes
Mystic Generating Station 7	MA	617.0	June 2021	Steam Turbine	-
Mystic Generating Station GT1	MA	14.2	June 2021	Combustion Turbine	-
Mystic Generating Station GT81	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT82	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT93	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT94	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station ST85	MA	315.0	June 2024	Combined Cycle	-
Mystic Generating Station ST96	MA	315.0	June 2024	Combined Cycle	-
Cleary Flood 8	MA	28.3	June 2023	Steam Turbine	-
Pawtucket Power Associates GEN1	MA	41.8	June 2022	Combined Cycle	-
Pawtucket Power Associates GEN2	MA	27.0	June 2022	Combined Cycle	-
Mass Inst Tech Cntrl Utilities/Cogen Plt CTG1	MA	21.2	Feb 2021	Combustion Turbine	-
Cape Gas Turbine GT4	MA	17.5	June 2022	Combustion Turbine	No FCA oblig. in Jun 2022
Cape Gas Turbine GT5	MA	17.5	June 2022	Combustion Turbine	No FCA oblig. in Jun 2022
William F Wyman Hybrid (Yarmouth) 1	ME	50.0	June 2020	Steam Turbine	No FCA oblig. in Jun 2020
William F Wyman Hybrid (Yarmouth) 2	ME	50.0	June 2020	Steam Turbine	No FCA oblig. in Jun 2020
William F Wyman Hybrid (Yarmouth) 3	ME	113.6	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
William F Wyman Hybrid (Yarmouth) 4	ME	632.4	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
Middletown 2	CT	113.6	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
Middletown 4	CT	414.9	June 2023	Steam Turbine	No FCA oblig. in Jun 2023

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type	Notes
Middletown 10	CT	18.5	June 2023	Steam Turbine	No FCA oblig. in Jun 2023
Essential Power Massachusetts LLC (West Springfield) 3	MA	113.6	June 2023	Steam Turbine	No FCA oblig. in Jun 2023
Maine Independence Station GEN1	ME	177.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Maine Independence Station GEN2	ME	177.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Maine Independence Station GEN3	ME	194.6	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Capitol District Energy Center (CDECCA) GTG	CT	39.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Capitol District Energy Center (CDECCA) STG	CT	30.7	June 2023	Combined Cycle	No FCA oblig. in Jun 2023

We note that after the modeling phase of this project had concluded, ISO New England posted detailed data on resource additions and retirements identified through FCA 15.[124] Large, notable additions include a 60 MW capacity addition at Ocean State Power in RI, 150 MW of new battery storage at Cranberry Point Battery Energy Storage in MA, 250 MW of new battery storage at Medway Grid in MA, 175 MW of new battery storage at Resource Cross Town in ME, and 20 MW of new battery storage at Great Lakes Millinocket in ME. Large notable addition include a 95 MW retirement at West Springfield 3 in MA. We expect that the inclusion of these changes would likely have limited impacts on projections of avoided energy costs, avoided capacity costs, and other avoided cost categories. We note that there are numerous uncertainties in any projection of the future as new resources are announced and others are retired and that future modeling efforts should endeavor to include the impacts of these resource changes.

Other resources

Note that our analysis also includes several other existing resources not discussed in the above sections. These include conventional hydroelectric resources, pumped-storage hydroelectric resources, and other natural gas-fired and oil-fired resources that are not assumed to exogenously retire during the study period.

[124] ISO New England. Last Accessed March 10, 2021. *FCA Obligations.* Available at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.

Other resources (e.g., biomass, wind) may have specific retirement dates.[125] These retirements and additions are accounted for in Section 4.4: *Renewable energy* .

Generic non-renewable resource additions

In addition to known and anticipated capacity additions, we allow the EnCompass model to construct generic unit additions of the types represented in Table 31 if it is determined there is a peak demand need. These parameters are similar, but not identical, to the parameters assumed in the 2018 AESC Study. Note that there are two types of each of these generic additions: one type that is built in Massachusetts load zones (and therefore subject to Mass DEP 310 CMR 7.74) and one type that is built in any of the other New England load zones.[126]

Table 31. Characteristics of generic conventional resources assumed in the EnCompass model

		Natural gas-fired combined cycle	Natural gas-fired combustion turbine
Maximum size	*MW*	702	237
Minimum size	*MW*	225	120
Heat rate	*Btu/kWh*	7,408	9,800
Variable O&M costs	*2021 $/MWh*	3.80	3.84
Fixed O&M costs	*2021 $/kW-yr*	11.93	19.16
NO_X emissions rate	*lb/MMBtu*	0.0075	0.0300
SO_2 emissions rate	*lb/MMBtu*	0	0
CO_2 emissions rate	*lb/MMBtu*	119	119

Note: Each type of generic resource may be fueled either with natural gas or fuel oil.
Source: Anchor Power Solutions New England database.

In addition to the exogenous storage builds described above, EnCompass can build out two- and four-hour duration storage resources if it determines it is optimal to do so. For these additional storage resources, we rely on capital expenditure data from the National Renewable Energy Laboratory's (NREL) 2020 Annual Technology Baseline (ATB).[127] NREL's 2020 ATB assumes that two-hour duration storage resources have capital expenditures of $963 per kW in 2018 before declining to $607 per kW in 2030 and thereafter increasing slightly to $647 per kW in 2040 (all values in nominal dollars). It assumes that four-hour duration storage resources have capital expenditures of $1,633 per kW in 2018 before declining to $1,029 per kW in 2030 and thereafter increasing slightly to $1,098 per kW in 2040 (all values in nominal dollars).

In general, the model builds new storage resources to meet reserve margin requirements as peak demand increases. As the model optimizes to meet a region's reserve margin requirement, it often finds

[125] These retirements include Pinetree Power (MA) in June 2022.

[126] More information on this environmental regulation can be found in the subsequent section on electricity commodities.

[127] National Renewable Energy Laboratory. Last accessed March 10, 2021. "Battery Storage." *Atb.nrel.gov.* Available at https://atb.nrel.gov/electricity/2020/index.php?t=st.

that storage resources are the most cost-effective resource available. In AESC 2021, we use a five-year optimization horizon, wherein the EnCompass model looks over the next five years to evaluate reliability requirements and costs in order to retire or build capacity as necessary.[128]

4.6. Transmission, imports, and exports

This section describes the existing, under construction, and planned intra-regional transmission modeled in the AESC 2021 study. It also describes our assumptions on new transmission between New England and other adjacent balancing authorities, and how we model imports over these inter-regional transmission lines in the analysis.

Intra-regional transmission

The interface limits used in the AESC 2021 study reflect both the existing system and the ongoing transmission upgrades discussed in ISO New England's Regional System Plan.[129] The transmission paths that link each of the 13 modeled regions in New England are based on transmission limits published by ISO New England (see Table 32).[130]

[128] Earlier AESC studies typically used one-year optimization horizons, largely because of computing power limitations. We have selected a five-year optimization horizon because this is roughly the horizon used to conceptualize and build large power plant projects (the FCM has a three-year horizon, but projects are conceptualized and qualified in the market before each auction at least one year and possibly more). When comparing resulting avoided costs in AESC 2021 with earlier studies, the most likely impact of this change in optimization horizon is to reduce "noise." In other words, this change is unlikely to cause avoided costs to be lower or higher but is more likely to reduce the year-on-year variation in costs.

[129] Regional System Plan documents can be found on ISO New England's website at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[130] Note that recent analysis by Synapse which examines large amounts of renewable construction has found that, depending on where and how much renewable capacity is built, at a certain point, additional transmission capacity is required to facilitate the movement of renewable generation in northern New England (i.e., areas with favorable wind capacity factors) to southern New England (i.e., areas of high customer load). In response to this, we model a new 600 MW transmission line between Maine West Central and Massachusetts Central beginning in 2023. The transmission line is intended to help limit issues of curtailment in Massachusetts.

Table 32. Group transmission limits

Transmission Limit	Path	A to B (MW)	B to A (MW)	Notes
NE East-West	NE Massachusetts Central - NE Massachusetts West	3,500	3,000	
	NE New Hampshire - NE Vermont			
	NE Rhode Island - NE Connecticut Northeast			
NE North-South	NE New Hampshire - NE Boston	2,725	2,725	
	NE New Hampshire - NE Massachusetts Central			
	NE Vermont - NE Massachusetts West			
	Hydro Quebec - NE Massachusetts Central			
NE SEMA/RI	NE Massachusetts Southeast - NE Boston	1,800	3,400	
	NE Rhode Island - NE Boston			
	NE Rhode Island - NE Connecticut Northeast			
	NE Rhode Island - NE Massachusetts Central			
NE Southeast	NE New Hampshire - NE Boston	5,150		
	NE Massachusetts Central - NE Boston			
	NE Rhode Island - NE Connecticut Northeast			
	NE Rhode Island - NE Massachusetts Central			
NE SW CT	NY K Long Island - NE Norwalk Stamford	2,800		
	NE Connecticut Northeast - NE Connecticut Southwest			
NE Connecticut	NE Connecticut Northeast - NY K Long Island	3,400	3,400	
	NY K Long Island - NE Norwalk Stamford			
	NE Massachusetts West - NE Connecticut Northeast			
	NE Rhode Island - NE Connecticut Northeast			
	NY G Hudson Valley - NE Connecticut Northeast			
New Brunswick	New Brunswick - NE Maine Northeast	variable	variable	-249 to 989
NY to NE	NY F Capital - NE Massachusetts West	variable	variable	-1,400 to 1,875
	NY D North - NE Vermont			
	NY G Hudson Valley - NE Connecticut Northeast			
Northport	NY K Long Island - NE Norwalk Stamford	variable	variable	-246 to 213
Quebec	Hydro Quebec - NE Vermont	2,000	2,000	
	Hydro Quebec – NE Massachusetts Central	217	100	
Cross Sound	NE Connecticut Northeast - NY K Long Island	variable	variable	-177 to 333

Inter-regional transmission

In addition, we model transmission between subregions of New England and adjacent balancing authorities in New York, Québec, and New Brunswick. As with intra-regional transmission, transmission lines between these regions are typically grouped into aggregate links with aggregate transfer capacities. These transmission links were developed by Anchor Power Solutions and updated by Synapse to ensure consistency with ISO New England's census of transmission lines. Imports and export quantities between New England and adjacent balancing areas are represented as fixed, based on recent historical quantities. Anchor Power Solutions has calibrated transfers on these lines such that transfers in historical years match actual historical transfers (see Table 33).

Table 33. Single pathway transmission limits with regions adjoining ISO New England

Zone A	Zone B	A to B Capacity (MW)	B to A Capacity (MW)
NE Connecticut Northeast	NY G Hudson Valley	600	600
NE Connecticut Northeast	NY K Long Island	330	330
NE Maine Northeast	NE Maine West Central	1,325	
NE Maine Northeast	New Brunswick	1,000	1,000
NE Maine Southeast	NE Maine West Central		1,500
NE Maine Southeast	NE New Hampshire	1,900	
NE Massachusetts Central	Hydro Quebec	217	217
NE Massachusetts West	NY F Capital	700	700
NE Norwalk Stamford	NY K Long Island	100	100
NE Vermont	Hydro Quebec	2,000	2,000

In addition, we model an incremental 1,200 MW transmission line from Québec to southeast Maine, per the topology of the New England Clean Energy Connect (NECEC) project.[131] This line is modeled as providing 9.45 TWh per year. This transmission line represents compliance with Massachusetts' 2017 Act to Promote Energy Diversity, and the associated long-term contracts signed per that legislation. Under Massachusetts Chapter 188 Section 83D, any contracts selected from the 83D solicitation process must be executed by no later than December 31, 2022. Per the latest data available, we assume that this line will instead be energized on July 1, 2023. Because this cost is assumed to be unavoidable to Massachusetts ratepayers, we do not develop or incorporate a price for this resource at this time.

4.7. Operating unit characteristics

Under the production cost modeling framework, EnCompass represents the detailed operations of individual generating units. This representation includes detail on following operational characteristics for dispatch data:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc.)

[131] See the New England Clean Energy Connect website at https://www.necleanenergyconnect.org/ for more information.

- Fuel type (including dual-fuel capabilities, startup fuel usage, and fuel delivery point or basin of origin)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)
- Variable operation and maintenance costs
- Commitment bid adders and multipliers
- Forced outage rates and planned outage rates and schedules
- Minimum up and down times, including maximum hours for warm and hot start scenarios
- Quick start, regulation, and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_X, and CO_2) with options for fixed, linear, quadratic, cubic, and quartic rates
- Seasonal and/or hourly capacity factor profiles for hydro, wind, and solar resources
- Acceptable curtailment levels for hydro, wind, and solar resources
- Storage charge and discharge rates (in MW), maximum energy-stored levels (in MWh), and payback rates for pumped hydropower and battery storage

Unit operational restraints (for example, minimum up times and ramp rates) are used to simulate unit commitment for hourly, chronological model runs. During unit operations, units incur costs based on fuel usage, variable O&M costs, and emission costs. Operational units also receive revenue based on their provision of grid services, including energy, regulation, and reserve services. Every model run produces an estimate of each unit's profitability given a dispatch pattern optimized to produce the lowest overall electric system costs for the region.

O&M costs for existing conventional generation are based on unit-specific data contained in EnCompass. Capital, operating, and maintenance costs and heat rate for new conventional generation are based on data from the 2017 AEO.

4.8. Embedded emissions regulations

This section contains detail on the emission regulations embedded in the electric commodity forecast.

The Regional Greenhouse Gas Initiative

All six New England states are founding members of RGGI. Under the current program design, the six states (along with New York, Maryland, Delaware, and New Jersey) conduct four auctions in each year in which CO_2 allowances are sold to emitters and other entities.

In August 2017, the RGGI states announced a set of proposed program changes for Years 2021 through 2030.[132] Under this extended program design, the RGGI states will continue to reduce CO_2 emissions through 2030, eventually achieving a CO_2 emissions level 30 percent below 2020 levels. This new program design has also put forth a number of changes to the "Cost Containment Reserve" (a mechanism that allows for the release of more allowances in an auction if the price exceeds a certain threshold) and the creation of an "Emissions Containment Reserve" (a mechanism which withholds a number of available allowances if the allowance price remains below a certain threshold). Together, these triggers effectively act as a floor and ceiling on RGGI prices.[133]

In addition, in recent years, the RGGI region has begun to expand. The first new state to join RGGI was New Jersey in January 2020 (rejoining the program after leaving it in 2012).[134] Later in 2020, Virginia finalized its rulemaking to join RGGI, effective January 1, 2021.[135] Finally, Pennsylvania is also developing a draft regulatory proposal to join RGGI (with the state slated to on January 1, 2023), though this rulemaking remains ongoing.[136]

Starting in April 2020, Pennsylvania Department of Environmental Protection tasked ICF International with developing RGGI price projections under a base case and a case where Pennsylvania joins the 11-state RGGI region. ICF International is the same firm that typically creates RGGI price forecasts on behalf of RGGI, Inc. This includes the RGGI price modeling generated in the 2016 RGGI Program Design, which served as the basis for RGGI prices in the 2018 AESC Study.[137]

Figure 27 displays the recent prices for RGGI allowances from auctions in 2010 through 2020. The figure includes a trajectory through 2030 where Pennsylvania does not join RGGI, plus a trajectory where

[132] The official announcement ca be found on the RGGI website at http://rggi.org/docs/ProgramReview/2017/08-23-17/Announcement_Proposed_Program_Changes.pdf.

[133] Regional Greenhouse Gas Initiative. December 19, 2017. "RGGi 2016 Program Review: Principles to Accompany Model Rule Amendments" *Rggi.org.* Available at rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf.

[134] New Jersey Department of Environmental Protection. Last accessed March 10, 2021. "Regional Greenhouse Gas Initiative." *state.ny.us.* Available at https://www.state.nj.us/dep/aqes/rggi.html.

[135] Virginia Department of Environmental Quality. Last accessed March 10, 2021. "Carbon Trading." *Deq.virginia.gov.* Available at https://www.deq.virginia.gov/air/greenhouse-gases/carbon-trading.

[136] Pennsylvania Department of Environmental Protection. Last accessed March 10, 2021. "Regional Greenhouse Gas Initiative." *Dep.pa.gov.* Available at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

[137] Regional Greenhouse Gas Initiative. Last accessed March 10. 2021. "Program Review." *Rggi.org.* Available at https://www.rggi.org/program-overview-and-design/program-review.

Pennsylvania does join RGGI. The RGGI price trajectory used in AESC 2018 is also shown, for reference. This figure also shows the prices associated with the emissions containment reserve (ECR) and cost containment reserve (CCR). Although two states (Maine and New Hampshire) do not use the ECR (the floor price), emissions from these two states make up a small fraction of RGGI-wide emissions and are unlikely to have a substantial effect on the price.

Because the RGGI region includes states not modeled in the AESC 2021 study (New York, Delaware, Maryland, New Jersey, Virginia, and Pennsylvania) and is in fact dominated by emissions outside of New England (see Figure 28), we model the effects of RGGI as an exogenous price rather than a strict cap on emissions. Note that neither of the scenarios recently modeled by ICF International displayed in Figure 27 exactly represent the assumptions used for the New England electricity system throughout this report (for example, they do not include any assumptions about transportation electrification, and both assume some amount of energy efficiency persists through 2030). Both of them indicate prices lower than what is implied by the ECR, in at least some years. Prices lower than the ECR are possible in situations where the full ECR (e.g., 10 percent of the allowances sold in any given auction) is withheld and there is still not enough demand at the trigger price for the remaining allowances. If only some of the ECR needs to be withheld, then the price will match the ECR trigger price.

The RGGI price modeled in AESC 2021 follows the ECR price (and follows a trajectory that extends the ECR’s 2020 to 2030 CAGR to 2031 to 2035). This trajectory reflects a future in which reductions in the RGGI cap are continued after the current compliance period ends in 2030, and a future in which New England electricity demand is higher than recently modeled by ICF International.

Figure 27. Historical RGGI allowance prices, recently modeled RGGI allowance prices, the prices associated with the cost containment reserve (CCR) and emissions containment reserve (ECR), and RGGI price used in AESC 2021

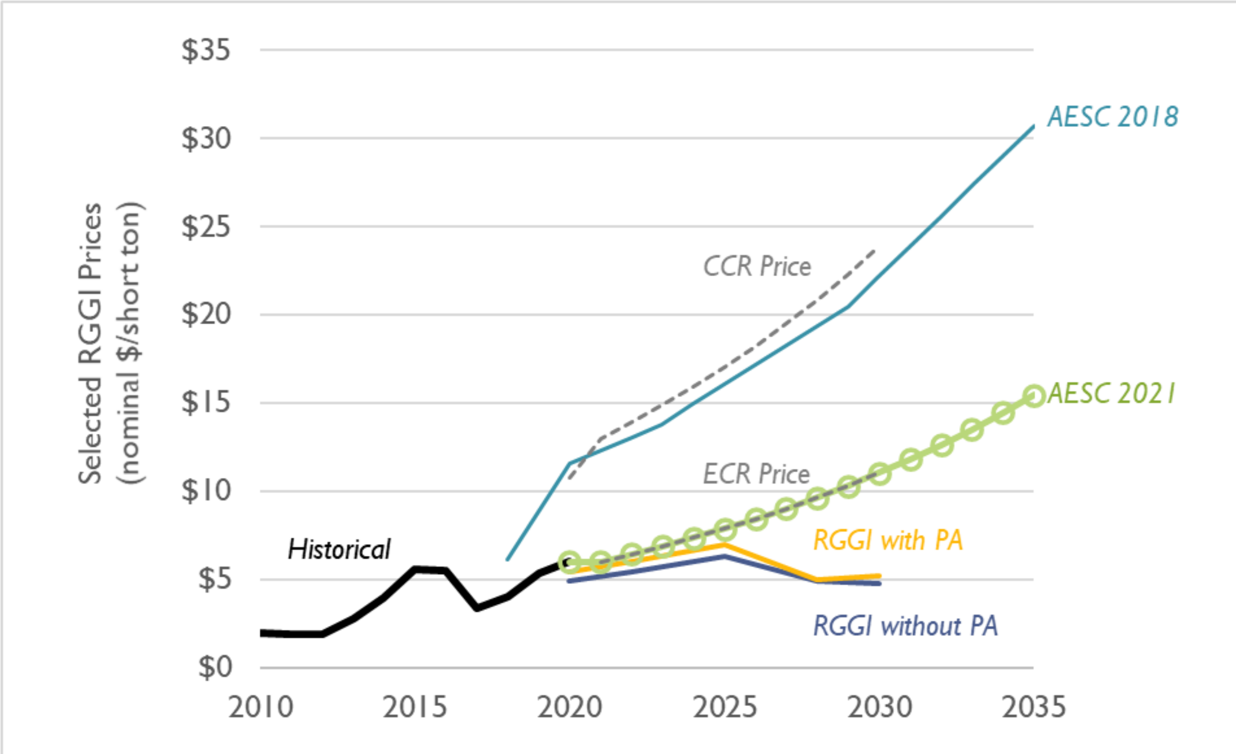
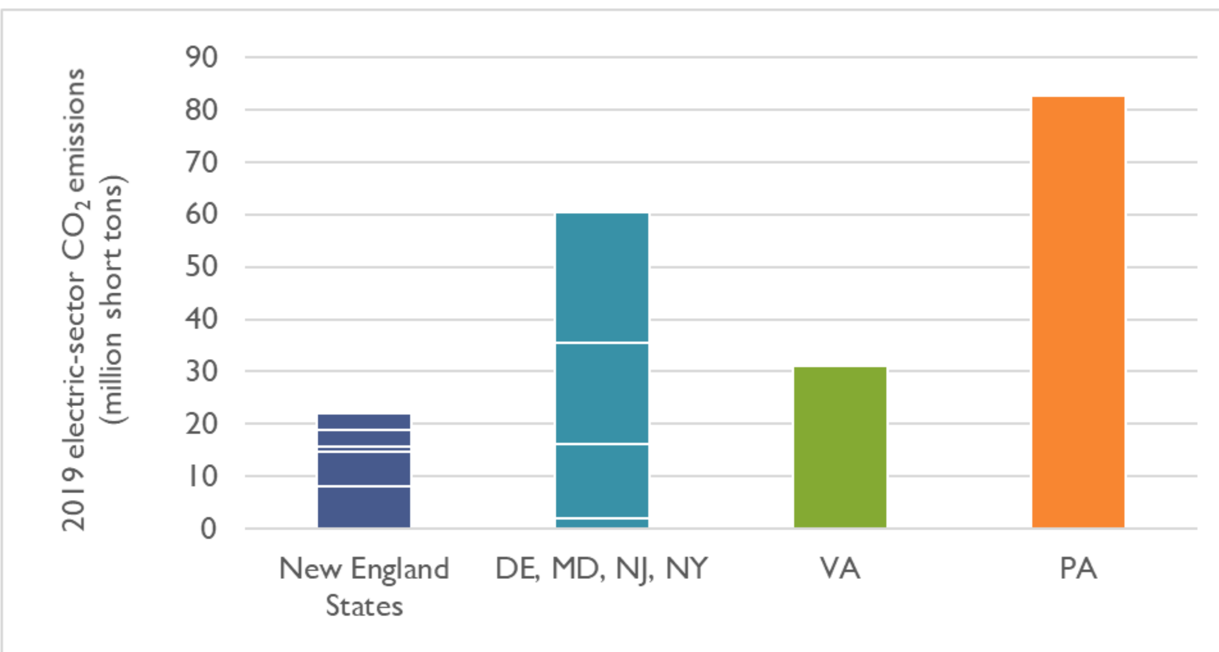


Figure 28. Electric sector CO_2 emissions in existing and proposed RGGI states, 2019



Source: EPA Air Market Programs dataset, available at ampd.epa.gov.

Massachusetts Global Warming Solutions Act and MassDEP regulations

AESC 2021 models the GHG regulations finalized by the Massachusetts Department of Environmental Protection (MassDEP) in 2017 in accordance with the Massachusetts Global Warming Solutions Act (GWSA). Under this finalized rule, MassDEP established two regulations that impact the electric sector: 310 CMR 7.74, which establishes a state-specific cap on CO_2 emissions from emitting generators in Massachusetts and 310 CMR 7.75, which establishes a Clean Energy Standard for Massachusetts load-serving entities (LSE). Impacts of these policies in $-per-metric-ton terms are available in Appendix G: .

310 CMR 7.74: Mass-based emissions limit on in-state power plants

310 CMR 7.74 assigns declining limits on total annual GHG emissions from identified emitting power plants within Massachusetts. Table 34 lists the affected power plants under this regulation. In the AESC 2021 study, we model this regulation as a state-wide limit through which plants receive CO_2 allowances pursuant to 310 CMR 7.74 at the start of each year.[138] The emissions limit starts at 9.1 million metric tons in 2018. It then declines by 2.5 percent of the 2018 emissions limit to 8.7 million metric tons in 2020, and 6.4 million metric tons in 2030 (see Table 24).[139]

In this analysis, we assume that both new and existing units fall under the same aggregate limit, as was done in the 2018 AESC study. We modeled all new and existing units as able to fully trade allowances pursuant to 310 CMR 7.74 throughout each compliance year. To simplify computation, we do not model ACPs or banking of CO_2 allowances pursuant to 310 CMR 7.74.

[138] We understand that allowances may be distributed through free allocation, through an auction, or through some combination thereof. We do not plan to make a distinction between these approaches in the 2018 AESC study, as the approach is unlikely to substantially impact allowance prices.

[139] Under the regulation, the emissions cap continues through 2050.

Figure 29. Analyzed electric sector CO_2 limits under 310 CMR 7.74

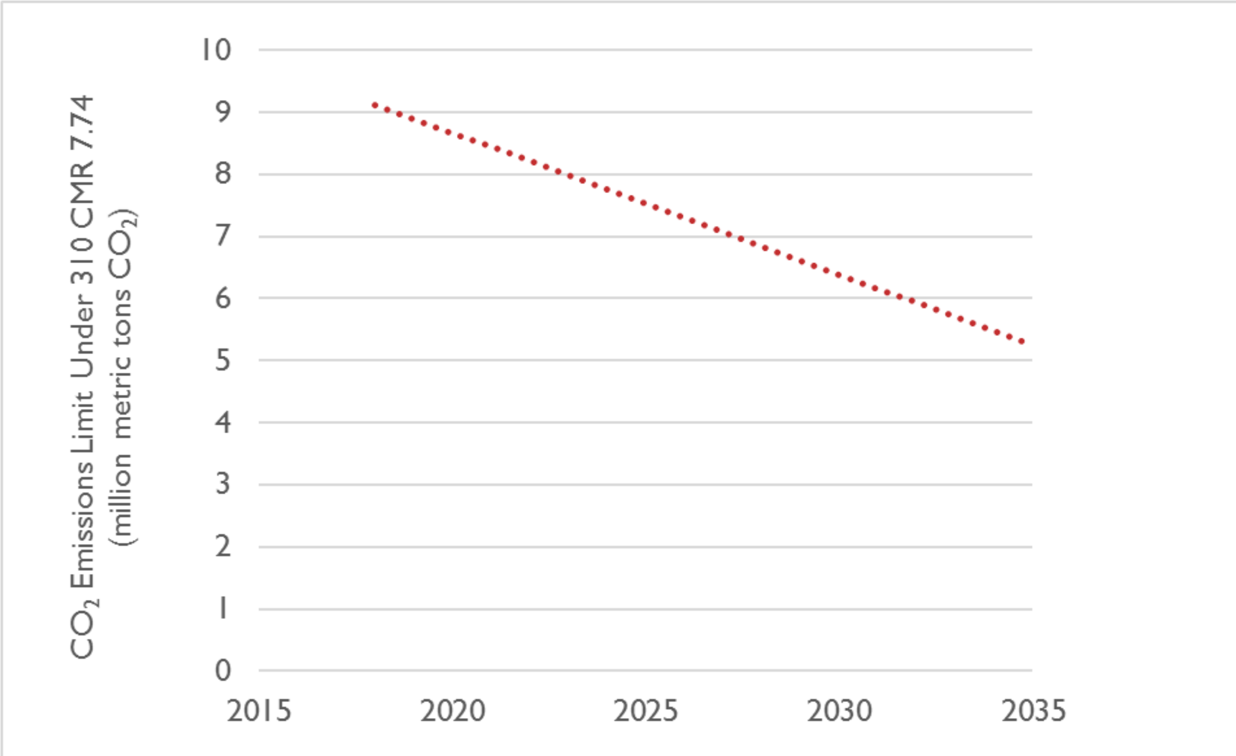


Table 34. List of generating units modeled as subject to 310 CMR 7.74

ORSPL	Facility	Unit Type	Fuel Type	Online Year (if recent)	EnCompass Unit Name
1588	Mystic	ST	Natural Gas	-	Mystic 7
1588	Mystic	CC	Natural Gas	-	Mystic CC
1592	Medway Station	GT	Oil	-	West Medway Jet
1595	Kendall Green Energy LLC	ST	Natural Gas	-	Kendall Square Jet
1595	Kendall Green Energy LLC	CC	Natural Gas	-	Kendall Square CC
1599	Canal Station	ST	Oil	-	Canal 1
1599	Canal Station	ST	Oil	-	Canal 2
1642	West Springfield	ST	Oil	-	West Springfield 3
1642	West Springfield	GT	Natural Gas	-	West Springfield 10
1642	West Springfield	GT	Natural Gas	-	West Springfield 1-2
1660	Potter	CC	Natural Gas	-	Potter Station 2
1660	Potter	GT	Natural Gas	-	Potter Station 2 GT
1678	Waters River	GT	Natural Gas	-	Waters River 1
1678	Waters River	GT	Natural Gas	-	Waters River 2
1682	Cleary Flood	ST	Oil	-	Cleary-Flood
1682	Cleary Flood	OT	Natural Gas	-	Cleary-Flood CC
6081	Stony Brook	CC	Oil	-	Stony Brook CC
6081	Stony Brook	GT	Oil	-	Stony Brook GT
10307	Bellingham	CC	Natural Gas	-	Bellingham Cogen
10726	MASSPOWER	CC	Natural Gas	-	Masspower
50002	Pittsfield Generating	CC	Natural Gas	-	Pittsfield
52026	Dartmouth Power	CC	Natural Gas	-	Dartmouth Power CC
52026	Dartmouth Power	GT	Natural Gas	-	Dartmouth Power GT
54586	Tanner Street Generation, LLC	CC	Natural Gas	-	L'Energia Energy Center
54805	Milford Power, LLC	CC	Natural Gas	-	Milford Power (MA)
55026	Dighton	CC	Natural Gas	-	Dighton Power
55041	Berkshire Power	CC	Natural Gas	-	Berkshire Power
55079	Millennium Power Partners	CC	Natural Gas	-	Millennium Power
55211	ANP Bellingham Energy Company, LLC	CC	Natural Gas	-	ANP Bellingham
55212	ANP Blackstone Energy Company, LLC	CC	Natural Gas	-	ANP Blackstone
55317	Fore River Energy Center	CC	Natural Gas	-	Fore River
1626	Footprint (Salem Harbor)	CC	Natural Gas	2017	Salem Harbor CC
1599	Canal 3	GT	Natural Gas	2019	Canal GT
59882	Exelon West Medway II LLC	GT	Natural Gas	2018	West Medway II

Note: This list includes some units that are modeled as retiring at some point in the study period.

310 CMR 7.75: Clean Energy Standard

This regulation establishes additional tranches of clean energy that are eligible to qualify for Clean Energy Certificates. More information on how we modeled this regulation (along with recent regulations for existing energy that were finalized in 2020) can be found in Section 4.4: *Renewable energy* .

Other environmental regulations

Several other environmental regulations are modeled in EnCompass and are thus embedded in the avoided energy costs. Other environmental regulations not included in the avoided energy costs include the following.

Sulfur dioxide (SO_2) and nitrogen oxides (NO_X)

Allowance prices are applied for annual SO_2 emissions covered under the Cross-State Air Pollution Rule (CSAPR) and the Acid Rain Program (ARP). Actual weighted average allowance prices from the 2020 SO_2 spot auction ($0.02 per short ton) for SO_2 are escalated at the rate of inflation through the study period, where SO_2 allowances are trading at a transaction cost.[140] These assumed prices are lower than the prices assumed in AESC 2018 ($0.52 per short ton, in 2018 dollars).

In AESC 2021 we assume no embedded NO_X prices. This assumption stems from three factors: the New England states being exempt from the CSAPR program; an assumption that currently proposed state-specific regulations in Massachusetts and Connecticut on ozone-season-NO_X are unlikely to be binding; and NO_X prices having been excluded from being modeled in previous AESC studies.

Mercury

As in past AESC studies, we assumed no trading of mercury and no allowance prices.

Other state-specific CO_2 policies

Similar to Massachusetts GWSA, all other New England states have specified a goal or target for reducing CO_2 emissions (see Table 35). Unlike Massachusetts, no other state has currently issued specific electric-sector regulations aimed at requiring that electric-sector emissions remain under a specified cap in some future year. In the AESC 2021 analysis, we do not include any embedded costs of GHG reduction compliance from states other than Massachusetts, and we assume no additional electric-sector regulations to those put forth under 310 CMR 7.74 and 7.75.[141]

[140] U.S. EPA. Last accessed March 10,2021. "2020 SO_2 Allowance Auction." *EPA.gov*. Available at https://www.epa.gov/airmarkets/2020-so2-allowance-auction#tab-2.

[141] Note that AESC 2021 does not assume that the full costs of the Massachusetts GWSA—or any other states' climate goals—are embedded in the energy prices and CES compliance prices. AESC 2021 only models the cost of compliance associated with regulations promulgated by MassDEP, including 310 CMR 7.74 and 310 CMR 7.75. In reality, the full cost of the Massachusetts GWSA and similar goals, targets, and requirements, will also be driven by (a) other, modeled impacts to the electric sector (i.e., new unit retirements, unit additions, natural gas prices, load forecasts) and (b) explicitly non-modeled impacts to the electric sector (i.e., energy efficiency and other DSM programs), (e) emission-reducing actions that occur outside the electric sector, and will be bounded by (c), the interim targets for specific milestone dates, which are in many cases, not yet established.

Table 35. State-specific GHG emission reduction targets 2050

State	2050 Target	Category	Sources	Interim Targets / Notes
CT	80% below 2001 levels	Statutory Target	Substitute House Bill No. 5600 Public Act 08-98: "An Act Concerning Global Warming Solutions" (Global Warming Solutions Act, or GWSA). See https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm	Senate Bill No. 7 Public Act No. 18-82 An Act Concerning Climate Change Planning and Resiliency. This 2018 Act established an interim goal of 45% below 2001's GHG emissions level by January 1, 2030. Available at https://www.cga.ct.gov/2018/act/pa/pdf/2018PA-00082-R00SB-00007-PA.pdf
ME	80% below 1990 levels by January 1, 2050	Statutory Target	38 MRSA §576-A. Greenhouse gas emissions reductions. See http://www.mainelegislature.org/legis/statutes/38/title38sec576-A.html	The legislation has the following interim goals: (a) Reduce GHG emissions by 45 percent by January 1, 2030 and (b) by January 1, 2040, the gross annual GHG emissions level must, at a minimum, be on an annual trajectory sufficient to achieve the 2050 annual emissions level.
MA	Net zero emission by 2050; gross emissions must be at least 85% below 1990 levels	Statutory Target	2008, Chapter 298 An Act Establishing the Global Warming Solutions Act. See https://malegislature.gov/laws/sessionlaws/acts/2008/chapter298 and https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download	Statutory target set at 80% below 1990 levels by 2050; GWSA requires the Executive Office of Energy and Environmental Affairs to set economy-wide GHG emission reduction goals for 2020, 2030, 2040, and 2050.
NH	80% below 1990 levels	Executive Target	2009 New Hampshire Climate Action Plan. See https://www.des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/documents/nhcap_final.pdf	n/a
RI	80% below 1990 levels	Statutory Target	TITLE 42, State Affairs and Government, Chapter 42-6.2 Resilient Rhode Island Act of 2014 – Climate Change Coordinating Council, Section 42-6.2-2. See http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM	Interim targets below 1990 levels include: (a) 10 percent below 1990 levels by 2020 and (b) 45 percent below 1990 levels by 2035;
VT	75% below 1990 levels	Statutory Target	Title 10 V.S.A. § 578 Conservation And Development Chapter 023: Air Pollution Control. See https://legislature.vermont.gov/statutes/section/10/023/00578	Interim targets below 1990 levels include: (a) 25 percent by January 1, 2012 and 50 percent by January 1, 2028.

Note: "Category" uses definitions from https://www.c2es.org/document/greenhouse-gas-emissions-targets/.

Federal CO_2 policies

In August 2018, the U.S. Environmental Protection Agency (EPA) announced a successor policy to the Clean Power Plan in the form of the Affordable Clean Energy (ACE) rule.[142] In January 2021, the D.C. Circuit vacated the ACE Rule and remanded it to EPA.[143] While other plans for federal action on CO_2 have been discussed in recent years, there are currently no regulations or policies in federal rulemaking. AESC 2021 models no other federal CO_2 policies.

[142] Synapse has written a short summary of an earlier ACE proposal at https://www.synapse-energy.com/about-us/blog/ace-whats-cards-emissions-reductions-0.

U.S. EPA. Last accessed March 11, 2021. "Affordable Clean Energy Rule." Epa.gov. Available at https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

[143] United States Court of Appeals USCA Case #19-1140. October 8, 2020. *American lung Association and American Public Health Association V. Environmental Protection Agency and Andrew Wheeler, Administrator, Respondents.* Available at https://statepowerproject.files.wordpress.com/2021/01/american-lung-assn-v.-epa-dc-cir.-no.-19-1140-per-curiam-decision.pdf.

5. AVOIDED CAPACITY COSTS

AESC 2021 develops avoided capacity prices for annual commitment periods starting in June 2021. The avoided capacity costs are driven by actual and forecasted clearing prices in ISO New England's FCM. The AESC 2021 forecast prices are based on observations made in recent auctions as well as expected future changes in demand, supply, and market rules. These prices are applied differently for cleared measures (i.e., measures that participate in the capacity market) and uncleared measures (i.e., measures that do not participate in the capacity market).[144]

We find that in Counterfactual #1, capacity prices range from $2.80 per kW-month to $4.34 per kW-month in 2021 dollars. Market-clearing prices in the out-years are principally determined by future changes in supply (including additions of battery storage, solar, wind, and occasionally new natural gas-fired power plants; as well as and retirements of thermal generation) and future changes in demand. Small year-on-year variations are due to changes in load, new resources coming online, and other resources retiring.

Compared to AESC 2018, capacity prices in AESC 2021 are about half as large on a 15-year levelized basis. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while prices in Counterfactual #1, Counterfactual #3, and Counterfactual #4 are relatively similar due to similar projections of annual loads. Small year-on-year observed differences are due to changes in load, new resources coming online, and other resources retiring.

5.1. Wholesale electric capacity market inputs and cleared capacity calculations

The following section provides a description of the analysis used to develop avoided capacity prices from the FCM auctions, as well as key input assumptions.

Description of Forward Capacity Market analysis

AESC 2021 develops avoided capacity prices from the FCM auction prices for power-years from June 2020 onward, using the actual results in auctions for delivery years 2021/22 through 2024/25 (FCAs 12 through 15) and extrapolating the historical results for the rest of the analysis period. The major assumptions used to simulate the future operation of the FCM include*:*

- ISO New England will continue to operate the FCM in a manner similar to recent years, including using a similarly shaped demand curve.

[144] "Uncleared resources" includes resources that qualify for the FCM but do not receive an obligation, as well as resources that simply do not participate in the market at all. They can also be thought of as "non-market" resources.

- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 9 through FCA 15. Most existing resources (renewables, nuclear, hydro, combined-cycle and modern combustion turbines) continue to bid in as price-takers, at or below likely FCM clearing prices.

- The build-out of the transmission system and additions of capacity in southern New England, as well as restrictions on the shifting of resources among zones in the *Competitive Auctions with Sponsored Resources* (CASPR) program, will minimize the risk of separation of capacity prices among the internal ISO capacity zones. The location of future potential zonal price spikes is difficult to assess; since the start of the FCM, ISO New England has observed or anticipated capacity-price separation for Maine, Connecticut, NEMA, northern New England (Vermont and New Hampshire), SEMA, SEMA-RI, and southeastern New England (NEMA, SEMA and Rhode Island). The transmission and ISO New England have made great efforts to eliminate binding capacity constraints between zones and have been successful since FCA 10.[145] We observed relatively minimal price separation in FCA 15, but we do assume no price separation in future years. Although it is possible that prices separation could occur in some future years, there is much uncertainty in terms of when this separation could occur, where it could occur, what level of price spread occurs, and how long the effect lasts. Thus, for purposes of simplicity, we assume a single regional clearing price in all modeled years.

- Retirements and additions of resources will change the amount of capacity in the low-price section of the supply curve, but the shape of the demand curve around the market-clearing point will remain similar to the shape of the supply curve in FCA 15.

- Due to retirements and load growth, FCM prices in the out-years are likely to be determined by the price of new resources, net of energy profits and operating-reserve revenues. Those new resources may be combustion turbines, combined-cycle units, or battery storage.

- The capacity price is set in the primary FCA based on the bids of existing resources, new unsubsidized resources, subsidized resources that could clear without the subsidy, and imports. New state-mandated resources, such as purchases of Canadian hydro power and offshore wind, are assumed to continue to participate in a substitution auction under the CASPR program, in which they can contract to take over the capacity supply obligation (CSO) of a generation resource that clears in the primary FCA and elects to permanently retire, giving up its transmission rights.[146] Once a sponsored resource has cleared in the CASPR market, it is then considered an existing resource and is able to participate in the primary auction. The existence of the CASPR market should encourage uneconomic generators (including a large amount of fossil steam capacity) to bid low to

[145] The abrupt non-price retirement of the entire Brayton Point station and Vermont Yankee in FCA 8 resulted in insufficient competition in the entire ISO in FCA 8 and in SEMA/RI in FCA 9.

[146] The retiring resource may pay the sponsored resource to take over the obligation (at a price less than the FCA clearing price) or the sponsored resource may pay the retiring resource for the right to become an existing resource in future FCAs.

clear the FCA, with the intent of offloading their CSOs to sponsored resources.[147] Once they are recognized as existing resources, sponsored resources are likely to bid largely as price-takers, since they will not want to shut down. A detailed discussion of the CASPR market is found below in subsection titled *ISO New England's Competitive Auctions with Sponsored Resources initiative*.

- For purposes of simplification, we assume that all resources are paid a single-year price, rather than a multi-year price. The option to elect a multi-year price will no longer be allowed beginning in FCA 16.[148]

AESC 2021 incorporates these assumptions to estimate FCM prices for power years from June 2025 onward.

Input assumptions to FCM analysis

The analysis of future capacity prices utilizes the results of the four most recent forward capacity auctions (FCA 12 through FCA 15), which are among the only ISO New England FCAs to clear at bid prices, rather than an administrative limit.[149] Table 36 shows the Rest of Pool (ROP) results for each round of each auctions. As the price falls in each round, the ISO increases the level of "demand," i.e., the amount of capacity it deems appropriate to procure. Simultaneously, the amount of supply that would clear falls with the price, and the excess of supply over demand falls even faster.

[147] ISO New England requires that an existing capacity resource which seeks to participate in the substitution auction offer a Test Price that indicates its estimate of a price at which it would not earn enough revenues to cover its going-forward costs. This document is reviewed by ISO New England's Internal Market Monitor. It is not yet apparent that this mechanism will preclude many existing resources from clearing.

[148] U.S. Federal Energy Regulatory Commission. December 2, 2020. *Order on Paper Hearing 173 FERC ¶ 61,198.* Available at https://www.iso-ne.com/static-assets/documents/2020/12/el20-54-000_12-2-20_order_new_entrant_rules.pdf.

[149] FCA 9 and FCA 10 also cleared at bid prices.

Table 36. FCA price results by round (rest-of-pool results only)

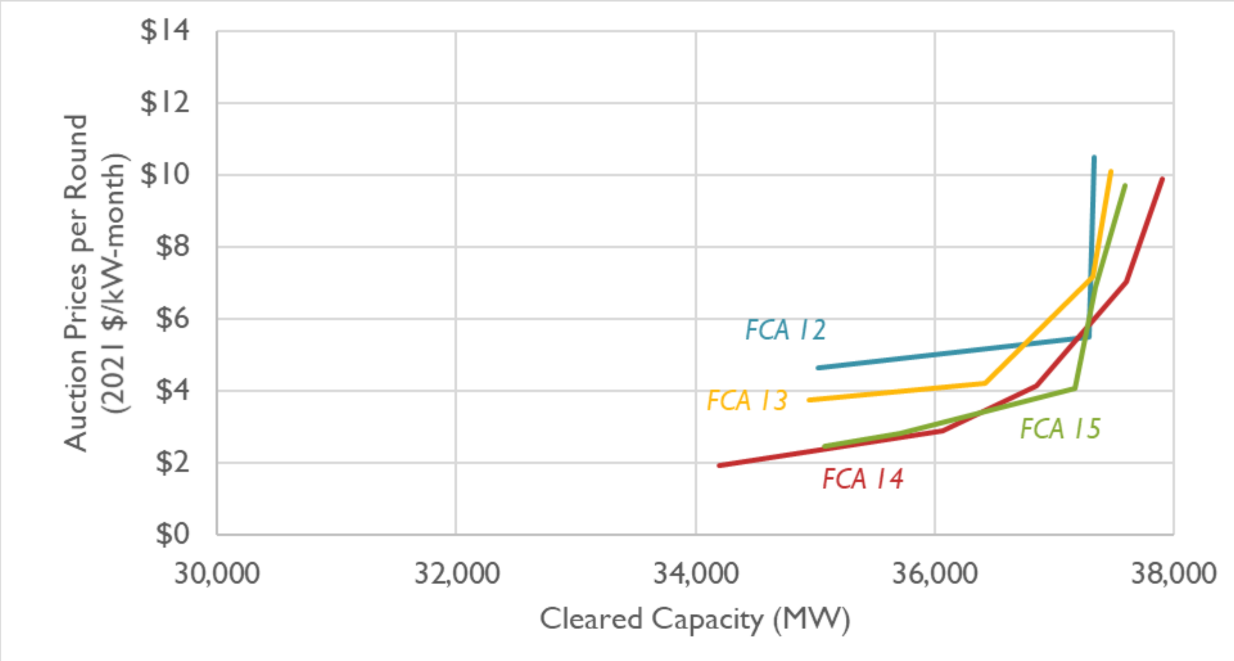
			CONE	Net CONE	Round 1	2	3	4	5
FCA 12	Price	*2021 $/kW-month*	$11.35	$8.04	$10.50	$8.00	$5.50	$4.63	
	Demand	*MW*			33,362	33,732	34,626	35,030	
	Excess	*MW*			3,972	3,589	2,669	0	
	Supply	*MW*			37,334	37,321	37,295	35,030	
FCA 13	Price	*2021 $/kW-month*	$11.07	$8.00	$10.30	$7.30	$4.30	$3.80	
	Demand	*MW*			33,437	33,897	34,724	34,954	
	Excess	*MW*			4,039	3,431	1,696	0	
	Supply	*MW*			37,476	37,328	36,421	34,954	
FCA 14	Price	*2021 $/kW-month*	$11.03	$7.87	$10.30	$7.30	$4.30	$3.00	$2.00
	Demand	*MW*			32,204	32,631	33,237	33,591	34,194
	Excess	*MW*			5,704	4,973	3,612	2,480	0
	Supply	*MW*			37,908	37,604	36,849	36,071	34,194
FCA 15	Price	*2021 $/kW-month*	$11.26	$8.20	$9.71	$6.88	$4.05	$2.83	$2.46
	Demand	*MW*			33,049	33,493	34,102	34,464	35,081
	Excess	*MW*			4,547	3,857	3,078	1,246	0
	Supply	*MW*			37,596	37,350	37,179	35,710	35,081

Notes: All prices have been converted to 2021 dollars.
Sources: See https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx and https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf.

Historical supply curves

Figure 30 shows the price results of the auction rounds, as a function of the supply available at that price. These are effectively the supply curves for capacity in each of these auctions. Each year, the market has been able to provide more capacity at a given price, or provide a given capacity at a lower price. The price curves for the last four auctions are relatively closely clustered and guide the AESC 2021 projection for future pricing. For future years, we move the FCA 15 supply curve right or left to reflect changes in capacity additions and retirements under each counterfactual.

Figure 30. FCA price results by round (effective supply curves)



Note: All prices have been converted into 2021 dollars.

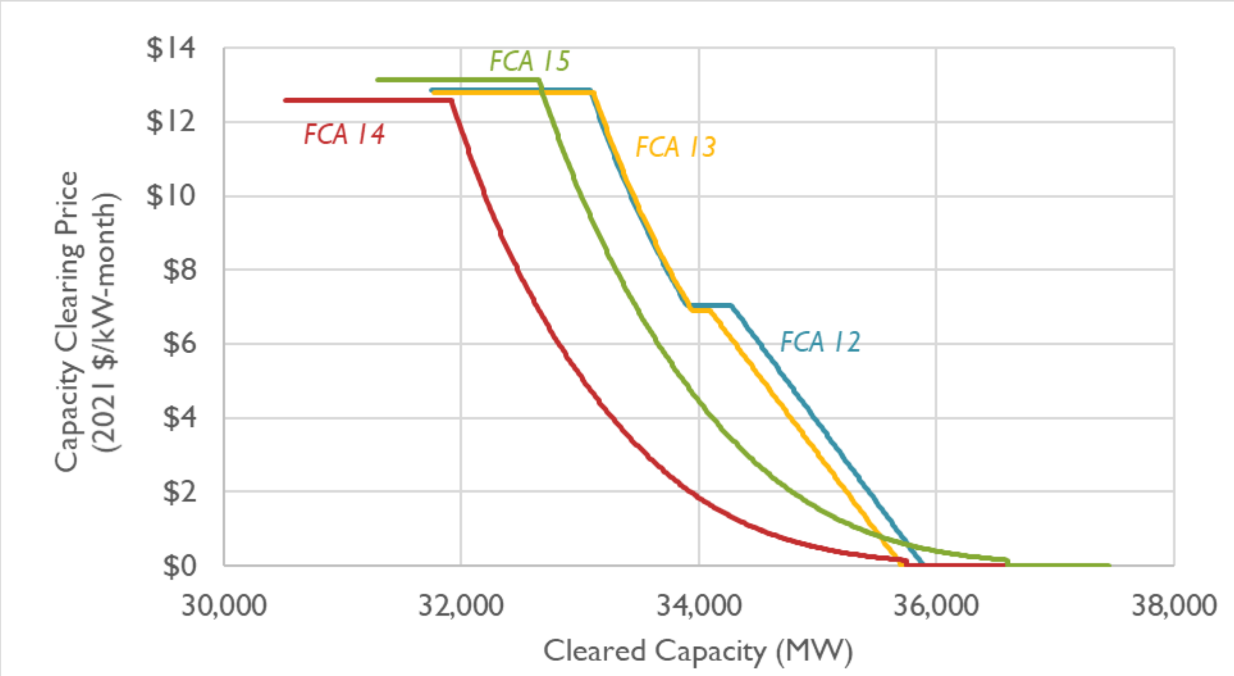
Historical demand curves

ISO New England has used the administrative demand curve for several years to provide greater stability in capacity prices and acquire additional resources when prices are low. Starting with FCA 14, the demand curve has been a smooth curve, shaped to mimic the change in loss-of-load expectation. The demand curve is scaled so that the capacity price equals ISO New England's estimate of cost of new entry (CONE) at the net installed capacity requirement (Net ICR).

Figure 31 shows the FCA 12 and FCA 13 demand curves, the last two auctions featuring a stepped demand curves, and the two more recent auctions that have used fully smoothed demand curves. Note that the curve for FCA 14 moved considerably lower relative to FCA 13, while the curve for FCA 15 moved back up.

To model FCA 16 and future years, we rely on the demand curve for FCA 15, shifted according to projected changes in demand in each counterfactual.

Figure 31. Recent FCA demand curves



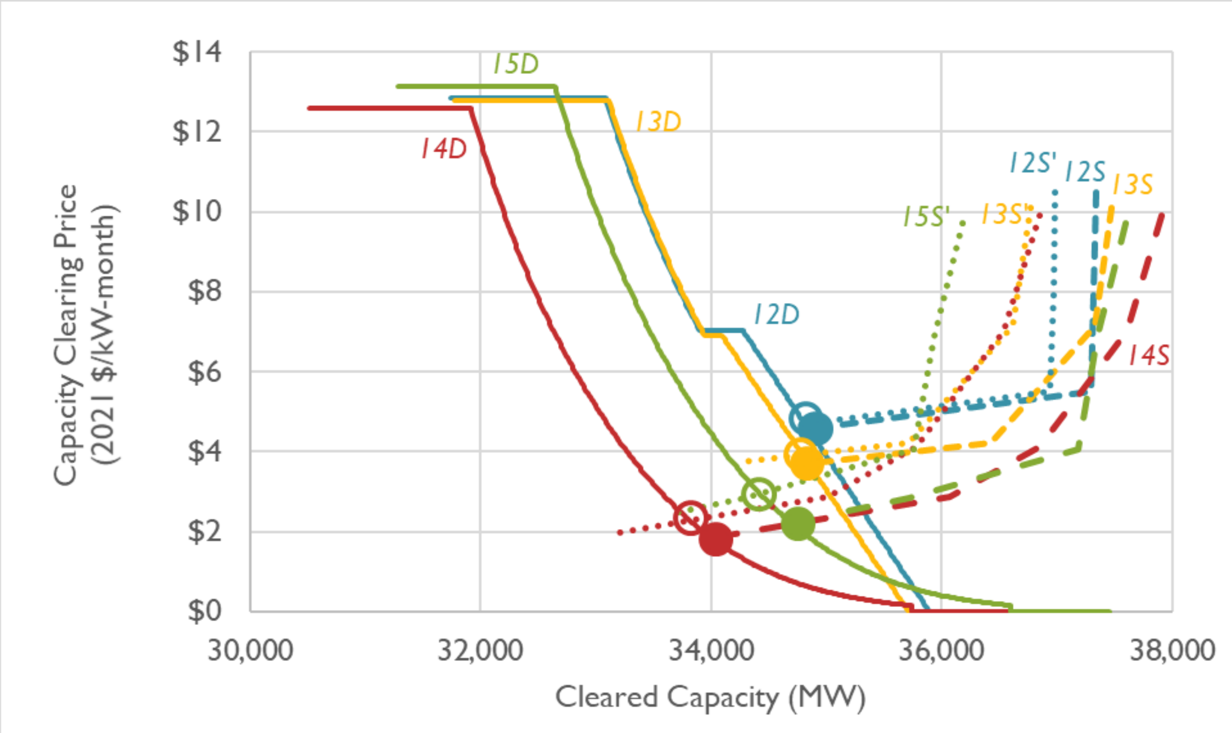
Note: All prices have been converted into 2021 dollars.

Historical capacity price results

Figure 32 shows the result of matching the demand and supply curves for FCA 12 through FCA 15. The figure shows each FCA represented by a distinct color. The figure then is further differentiated with:

- A solid line representing the demand curve for each FCA
- A dashed line representing the supply curve for each FCA
- A dotted line for the supply curve for Counterfactual #1 that excludes the post-2020 energy efficiency for each FCA
- A solid circle that shows the actual market clearing price for each auction
- An empty circle that indicates what the clearing price would have been if not for energy efficiency that was installed in 2021 and later years

Figure 32. Market clearing capacity prices for FCA 12 through FCA 15



Notes: Solid lines marked "D" are demand curves, dashed lines marked "S" are actual supply curves, and dotted lines marked "S'" are supply curves absent post-2020 energy efficiency. Solid circles denote the clearing price under actual conditions while empty circles denote what the clearing price would have been but for post-2020 energy efficiency. Only results for rest-of-pool are shown.

The exact clearing price in each auction depends on the size of the marginal unit, since ISO New England accepts entire units rather than individual megawatts. Hence, the actual FCA supply curve does not quite intersect with the demand curve, especially for FCA 12 and FCA 14; these clearing prices must have been set by large units. Table 37 summarizes the clearing prices for the actual and hypothetical "without post-2020 EE" cases described in Figure 32.

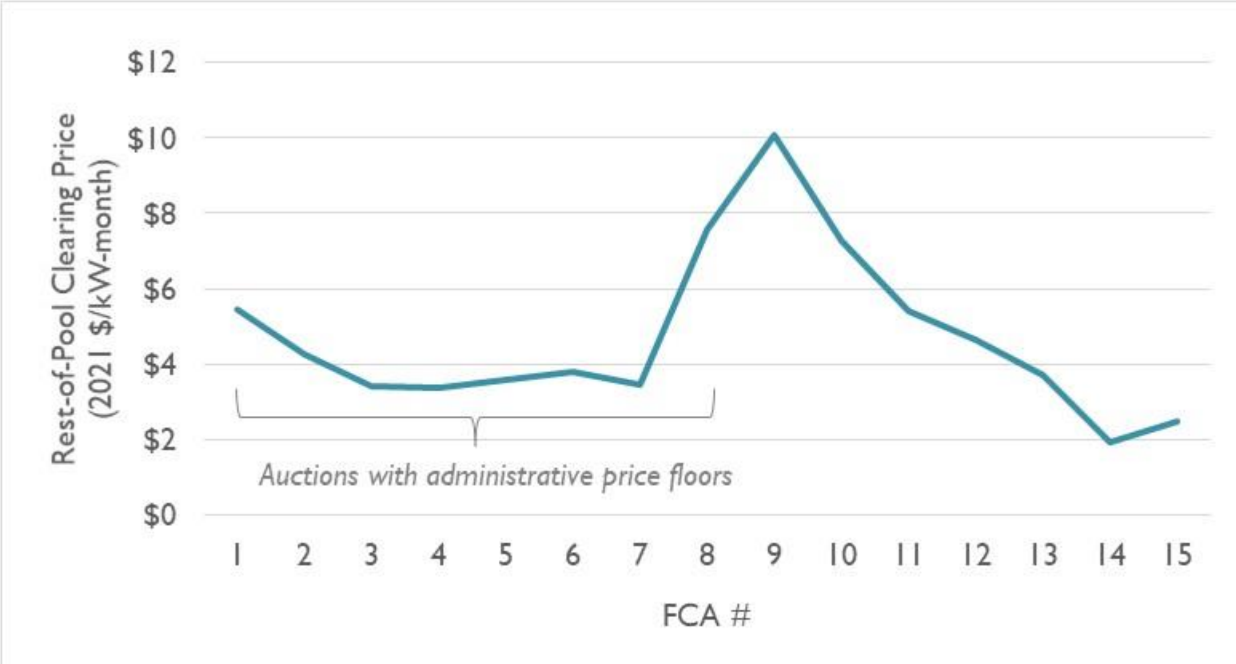
Table 37. Capacity prices for recent and pending FCAs (2021 $ per kW-month)

Commitment Period (June to May)	**FCA**	**Actual Clearing Price** *2021 $*	**Actual Clearing Price Without post-2020 EE** *2021 $*
2021/2022	12	$4.63	$4.77
2022/2023	13	$3.73	$3.96
2023/2024	14	$1.92	$2.47
2024/2025	15	$2.46	$3.29

Note: Rest-of-pool prices only.

As a point of reference, Figure 33 illustrates the actual clearing prices since the start of the FCM. The average rest-of-pool clearing prices over the four most recent auctions is $3.19 kW-month.

Figure 33. Forward capacity auction clearing prices for all past auctions (rest-of-pool prices only)



Note: All prices have been converted into 2021 dollars.

Projecting future capacity prices

For each subsequent auction after FCA 15, we estimate both the demand curve and the supply curve, using the steps described above. The demand curve shifts to the right as the forecasted peak increases. The supply curve shifts left or right, depending on the extent of resource retirements and additions.[150] The intersection of these two curves indicates the capacity price.

Table 38 depicts the estimated peak demand under each counterfactual in the future years where prices are simulated (as opposed to 2021 through 2024, where capacity prices are based on actual observations). We calculated peak demand based on the aggregate hourly peak load from the drivers described in Section 4.3: *New England system demand*. Peak demand for Counterfactuals #1, #3, and #4 are relatively similar due to the similarity of their underlying assumptions. Peak demand for Counterfactual #2 is substantially lower, as this counterfactual incorporates incremental energy efficiency after 2020.

[150] The supply curve will also change with the economics of continued operation of resources, the operators' bidding strategies, the availability of imports, ISO New England's rules for resource eligibility, and other factors. We have not estimated those changes, which will be driven by factors that are difficult to forecast.

Table 38. Projected cumulative change in demand (GW), relative to FCA 15

		Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
FCA 16	2025	0.5	0.1	0.5	0.5
FCA 17	2026	0.8	0.1	0.8	0.8
FCA 18	2027	1.2	0.2	1.2	1.2
FCA 19	2028	1.6	0.2	1.6	1.6
FCA 20	2029	2.1	0.4	2.1	2.1
FCA 21	2030	2.5	0.5	2.5	2.5
FCA 22	2031	2.9	0.6	2.9	2.9
FCA 23	2032	3.3	0.8	3.3	3.3
FCA 24	2033	3.9	1.0	3.9	3.9
FCA 25	2034	4.4	1.3	4.4	4.4
FCA 26	2035	4.9	1.5	4.9	4.9

Table 39 depicts the available supply under each counterfactual in the future years where prices are simulated (as opposed to 2021–2024, where capacity prices are based on actual observations). Projected supply is based on the impacts from the drivers described in Chapter 4. *Common Electric Assumptions*, Chapter 7. *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies*, and the dynamics of the CASPR auction described below in the subsection titled *ISO New England's Competitive Auctions with Sponsored Resources initiative*. The supply depicted here is the net cumulative supply relative to FCA 15, after accounting for conventional plant retirements and additions, as well as CASPR-eligible plant additions.

Projected supply for Counterfactuals #1, #3, and #4 are relatively similar due to the similarity of their underlying assumptions. Projected supply for Counterfactual #2 is substantially lower, as this Counterfactual incorporates incremental energy efficiency after 2020. See Chapter 6. *Avoided Energy Costs* for more discussion on these results.

Table 39. Projected cumulative change in supply (GW), relative to FCA 15

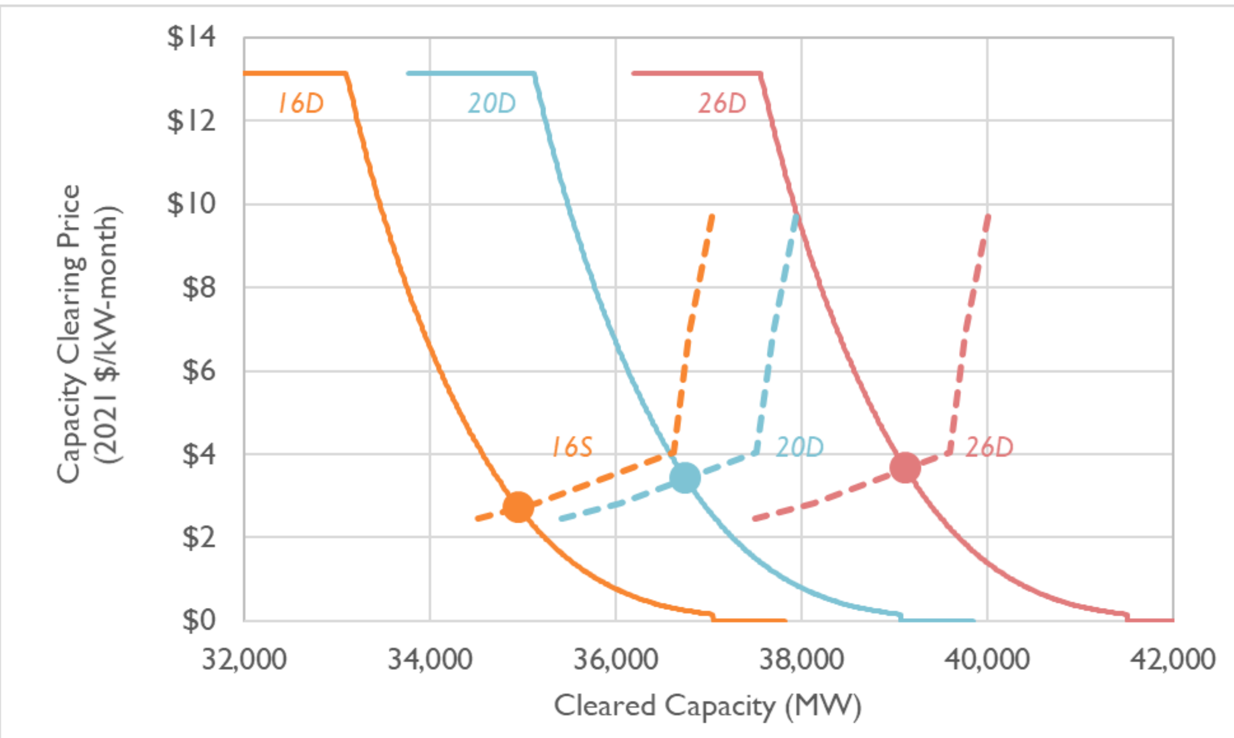
		Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
FCA 16	2025	-0.6	-0.9	-0.3	-0.3
FCA 17	2026	-0.5	-0.8	-0.2	-0.2
FCA 18	2027	-0.4	-1.8	-1.0	-0.9
FCA 19	2028	-0.4	-1.7	-0.9	-0.9
FCA 20	2029	-0.3	-1.7	-0.9	-0.8
FCA 21	2030	0.3	-2.1	-0.5	-0.4
FCA 22	2031	0.4	-2.1	0.2	0.3
FCA 23	2032	0.4	-2.0	0.3	0.3
FCA 24	2033	1.1	-2.0	0.9	1.0
FCA 25	2034	1.1	-1.9	1.0	1.0
FCA 26	2035	2.4	-1.3	2.3	2.3

As described above, our simplified capacity market model does not estimate geographic price separation in any years after FCA 15. We observed relatively minimal price separation in FCA 15, but we do assume no price separation in future years. Although it is possible that prices separation could occur in some future years, there is much uncertainty in terms of when this separation could occur, where it could occur, what level of price spread occurs, and how long the effect lasts. Thus, for purposes of simplicity, we assume a single regional clearing price in all modeled years.

Results

As described above, for each year and each counterfactual, MW differences in demand (relative to FCA 15) are added to or subtracted from the FCA 15 demand curve to create a new future demand curve. A similar operation is performed for the FCA 15 supply curve using the changes in supply. Figure 34 illustrates the resulting market clearing prices in Counterfactual #1 for a selection of years. In this counterfactual, capacity prices in FCA 16 and later range from $2.72 per kW-month to $4.67 per kW-month in 2021 dollars. The market-clearing prices in the out-years are principally determined by whether the balance of the qualified and cleared capacity additions, primarily from battery storage and offshore wind, and retirements of thermal generation (fossil steam, combustion turbines, some older combined-cycle units, and some biomass), and how the resulting supply compares to the change in demand.

Figure 34. Forecast of selected FCA prices in Counterfactual #1 (2021 $ per kW-month) in rest-of-pool region



Notes: Solid lines marked "D" are demand curves while dotted lines marked "S" are supply curves. Empty circles denote estimated clearing prices. Several supply curves are not marked on this figure, but lie in between 16S and 26S. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

These capacity prices, projected for 2025 and later years, are then appended to actual capacity prices for 2021–2024 (in the case of Counterfactual #2) and capacity price projections for these same years but for the impact of post-2020 energy efficiency (in the case of Counterfactuals #1, #3, and #4). Table 40 and Figure 35 compare the complete capacity price projections for each counterfactual. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while Counterfactual #1, Counterfactual #3, and Counterfactual #4 are relatively similar due to similar projections of annual loads. Small year-on-year differences are due to changes in load, new resources coming online, and other resources retiring. These are the avoided capacity costs used for cleared resources.

Compared to AESC 2018, the AESC 2021 capacity prices are about half as large on a 15-year levelized basis. Prices tend to be lower and remain low because the amount of demand and supply resources modeled in future years is expected to produce clearing prices that occur in a relatively low and shallow part of both the supply and demand curves.[151]

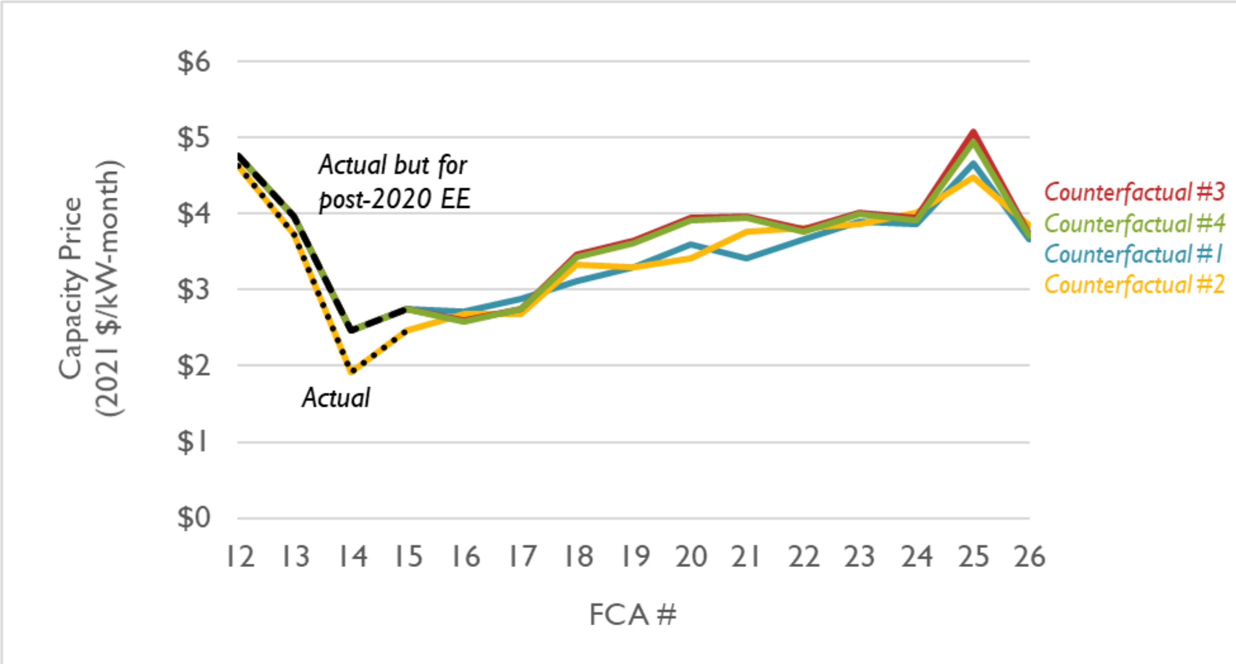
Table 40. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2020 EE	AESC 2021				AESC 2018
				Counter-factual #1	Counter-factual #2	Counter-factual #3	Counter-factual #4	
2021/2022	12	$4.63	$4.77	$4.77	$4.63	$4.77	$4.77	$4.99
2022/2023	13	$3.73	$3.96	$3.96	$3.73	$3.96	$3.96	$5.10
2023/2024	14	$1.92	$2.47	$2.47	$1.92	$2.47	$2.47	$5.21
2024/2025	15	$2.46	$2.75	$2.75	$2.46	$2.75	$2.75	$5.50
2025/2026	16			$2.72	$2.69	$2.59	$2.59	$5.95
2026/2027	17			$2.88	$2.69	$2.75	$2.75	$6.46
2027/2028	18			$3.11	$3.33	$3.46	$3.43	$6.95
2028/2029	19			$3.30	$3.30	$3.65	$3.62	$7.45
2029/2030	20			$3.59	$3.41	$3.94	$3.92	$7.95
2030/2031	21			$3.42	$3.77	$3.97	$3.94	$6.95
2031/2032	22			$3.67	$3.81	$3.79	$3.77	$7.45
2032/2033	23			$3.90	$3.86	$4.02	$3.99	$7.95
2033/2034	24			$3.86	$4.02	$3.95	$3.92	$6.95
2034/2035	25			$4.67	$4.47	$5.09	$4.95	$7.45
2035/2036	26			$3.66	$3.86	$3.73	$3.71	$7.95
15-year levelized cost				**$3.51**	**$3.45**	**$3.65**	**$3.63**	**$6.63**
Percent difference				**-47%**	**-48%**	**-45%**	**-45%**	

Notes: Levelization periods are 2021/2022 to 2035/2036 for AESC 2021 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 0.81 percent for AESC 2021 and 1.34 percent for AESC 2018. Values for "Actual" and "Actual but for post-2020 EE" are calculated based on rest-of-pool. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

[151] The shapes of both of these curves are determined by data published by ISO New England, either directly through a publication by ISO New England (in the case of the FCA 15 demand curve) or indirectly via auction results (in the case of the FCA 15 supply curve).

Figure 35. Comparison of capacity prices in AESC 2021 across different counterfactuals



Note: Values for "Actual" and "Actual but for post-2020 EE" are shown based on rest-of-pool. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

5.2. Uncleared capacity calculations

Any load reduction that clears provides avoided capacity costs in the year that the resource participates in the capacity auction. For example, if a program administrator has bid 1 MW into FCA 15 and expects to deliver that 1 MW starting in the summer of 2024 (the beginning of the FCA 15 commitment period), that benefit will receive the full avoided capacity cost benefit starting in 2024. Likewise, if this measure is re-bid into each subsequent auction for the duration of its life, it will receive an avoided capacity cost equal to the market clearing price for all future years.

But not all resources are bid into the FCA. Program administrators may choose to claim lower savings from new installations until the program is approved, funding is more certain, or the rate of installation is better known. Thus, a program administrator may bid some (or only a portion) of the anticipated capacity into the FCA.[152]

This remaining capacity is known as "uncleared" capacity. Unlike cleared capacity, the benefit associated with this resource is not simply the capacity price multiplied by the resource's capacity. Instead,

[152] As long as it is "qualified" to participate in auctions (per ISO New England's definition and rules), the uncleared portion of the resource may be later bid into monthly annual reconciliation auctions (MRA), annual reconciliation auctions (ARA), as well as for the FCAs for later commitment periods. In general, ARA prices are lower than FCA prices; for the ARAs completed for the commitment periods ending in 2018 to 2021, the first ARA averaged about 76 percent of the FCA price, the second ARA averaged 37 percent, and the third ARA averaged 31 percent.

uncleared capacity utilizes a "phase-in" and "phase-out" schedule that approximates how the impacts of these resources are indirectly captured in the development of inputs to ISO New England's FCM.

Phase-in

Each year, ISO New England generates a demand forecast using a complex regression analysis of load, weather, and a time trend over 15 years of historical summer (primarily July and August) daily peak loads. As load reductions from uncleared efficiency programs appear in the model's data, forecasts of capacity requirements (i.e., load) are reduced.[153] Because each annual capacity auction is performed three years in advance of a commitment period, and because there is a lag in terms of when changes to load appear in the load forecast used for a capacity auction, we assume that benefits from uncleared capacity do not start until 5 years after their installation date. Table 41 describes a hypothetical timeline where a measure is installed in 2019, but does not produce an impact on the capacity market for another five years.

Table 41. Illustration of when uncleared capacity begins to have an effect

Year	Event
2019	Measure is installed and begins to reduce load.
2020	ISO New England publishes a load forecast that is partially impacted by the load reductions installed in the previous year.
2021	An annual capacity auction occurs (effective three years from now in 2024). The demand curve in this auction is based on the load forecast made in the previous year.
2022	-
2023	-
2024	The year the prices from the capacity auction take place. The uncleared measure now begins to have an impact.

Phase-out

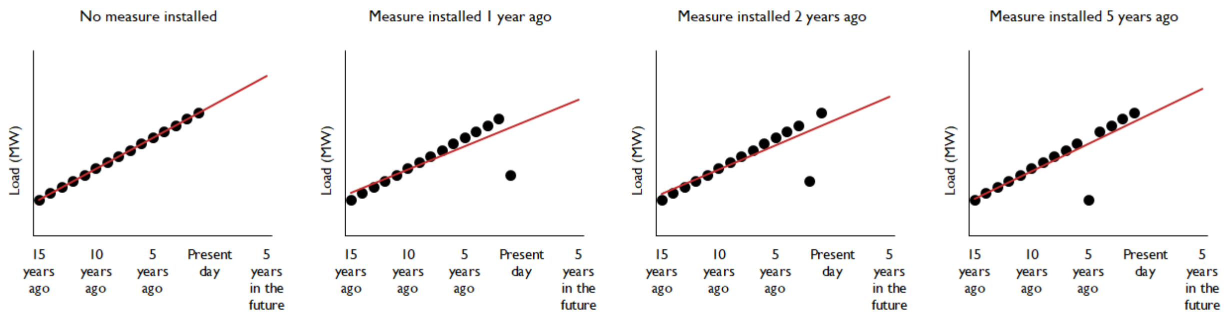
However, once impacts begin (in year N+5), they are discounted to some degree. The phase-in of these impacts is non-linear, depending on the duration of load reductions and when in the 15-year dataset the reductions occur. The following paragraphs illustrate two examples of this phenomenon.

Figure 36 illustrates how a measure with a one-year measure life may impact the load forecast used in the FCM In each panel, the black dots illustrate historical load data, with the right-most dot representing data from the most recent historical year. The red line is a simple best-fit linear regression continuing for several years into the future. The first panel shows a base case with 15 years of data and no reduction in load. The second panel shows the effect of a one-year load reduction on a linear regression when that load reduction occurs in the most recent historical year. The third panel shows an alternate situation, where the one-year load reduction occurred two years in the past. The final panel shows a situation

[153] The effect of the load reduction on the coefficients of the weather variables is less predictable and depends on the weather conditions on the days affected by the program.

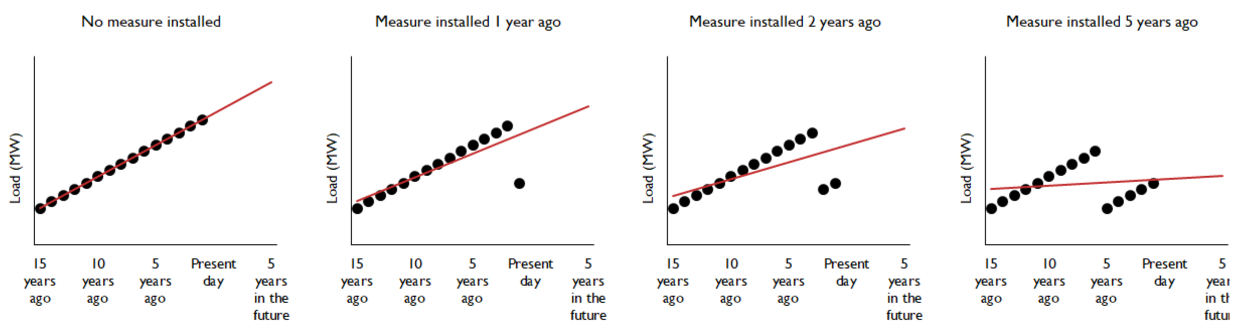
where the one-year load reduction has occurred five years in the past. These examples show that the single-year load reduction has the largest impact on the forecast when it is at the end of the data, in the most recent past year. When the reduction has aged, the impact on the forecast is more modest. This is because the critical point is more towards the center of the 15-year time series rather than on the edge.

Figure 36. Illustrative impacts of a single-year load reduction on the peak forecast



In a second example, Figure 37 depicts the impact of a load reduction with a five-year measure life. This measure is illustrated at having been installed at various times: not at all in the first panel, one year ago in the second panel, two years ago in the third panel, and five years ago in the final panel. The program's effect on the load forecast (the red line) increases with multiple years of operation. The longer a measure is in effect, the flatter the resulting trend line.

Figure 37. Illustrative impacts of a five-year load reduction on the peak forecast



Load forecast effect (LFE) schedule

The above observations lead us to a set of conclusions:

In reality, we would expect the capacity market to respond to the cumulative effect of each program on the load forecast (and hence the demand curve used in the auction). Because of the complexity associated with these forecast reductions, we approximate the incremental phase-in schedule using simplified blocks (see Table 42). We assume that the first year a one-year measure produces an impact on the load forecast, the uncleared capacity benefit is scaled by 30 percent. In the following three years, the benefit is scaled by 20 percent. In the fourth year, the benefit is scaled by 10 percent, and by the fifth year, we assume the benefit is erased completely.

Table 42. LFE schedule for a measure with a one-year lifetime installed in 2021

	Percent of uncleared capacity impact in place
2021	0%
2022	0%
2023	0%
2024	0%
2025	0%
2026	30%
2027	20%
2028	20%
2029	20%
2030	10%
2031	0%
2032	0%
2033	0%
2034	0%
2035	0%

However, because these effects are assumed to be driven by the cumulative impact of a measure, if a measure produces savings for multiple years, it will have a greater and more sustained price effect. Table 43 shows the schedule assumed for measures with lifetimes varying from one to ten years.[154] Each successive phase-in column has the same series of values (equal to the effect of a one-year program), offset by one year. The percentage of the actual load reduction integrated into the forecast is the sum of the effect from each program year.[155] For example, in 2027, the assumed effect is equal to 50 percent, or the sum of the 2026 impact from a one-year program and the 2027 impact from a one-year program.

[154] See the *AESC 2021 User Interface* for a detailed schedule of uncleared capacity DRIPE effects for measures lasting one through 35 years. We note that AESC 2018 described there being two separate LFE schedules for long-duration and short-duration measures. This is because for measure lives 10 years or greater, the LFE schedule is effectively same for the first 15 years of a measure lifetime (see the last column in Table 43). In the *AESC 2021 User Interface*, we explicitly calculate the uncleared resource effects for 35 different measure lives for the entire study period (2021 through 2055) and thus no longer need to make this simplifying assumption.

[155] This modeling is a simplification to facilitate screening. In some simple trend-line examples, the forecast can actually fall by slightly more than the full load reduction in some years. Given the effects of other variables on the regression equation, and the uncertainties in the decay schedule, greater complexity in modeling the capacity DRIPE effect does not seem warranted.

Table 43. LFE schedule for uncleared capacity value for measures with L lifetimes installed in 2021

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
2021	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2022	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2026	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
2027	20%	50%	50%	50%	50%	50%	50%	50%	50%	50%
2028	20%	40%	70%	70%	70%	70%	70%	70%	70%	70%
2029	20%	40%	60%	90%	90%	90%	90%	90%	90%	90%
2030	10%	30%	50%	70%	100%	100%	100%	100%	100%	100%
2031	0%	10%	30%	50%	70%	100%	100%	100%	100%	100%
2032	0%	0%	10%	30%	50%	70%	100%	100%	100%	100%
2033	0%	0%	0%	10%	30%	50%	70%	100%	100%	100%
2034	0%	0%	0%	0%	10%	30%	50%	70%	100%	100%
2035	0%	0%	0%	0%	0%	10%	30%	50%	70%	100%

Note: Measures installed in subsequent years utilize the same schedule, but shifted by an appropriate number of years (e.g., a measure installed in year 2022 would see effects beginning in year 2027). Note that effects for measures with measure lives of six years or greater continue to phase out after 2035. Because of this, the AESC 2021 User Interface calculates these effects through 2050 for each individual year, rather than extrapolating values.

Reserve margin requirements

Each year ISO New England calculates a net installed capacity requirement (Net ICR) that represents the target amount of capacity to be purchased in the Forward Capacity Auction in order to plan for a system that meets the accepted standard for resource adequacy. While the actual amount of capacity procured depends upon many factors, the percentage by which the Net ICR exceeds the projected system peak is the planning reserve margin. Over the last four auctions, the reserve margin has averaged 14.2 percent (see Table 44). We assume this average value persists from 2025 through 2035 for all counterfactuals. AESC 2021 estimates reserve margins independently of clearing prices. This is because the planning reserve margins are based upon the target amount to be procured, and actual capacity purchased is often much higher as incumbent generation owners are willing to accept very low capacity payments dictated by a downward sloping demand curve.

Table 44. Calculated reserve margins

Summer	FCA #	Calculated reserve margin
2021	12	15%
2022	13	16%
2023	14	13%
2024	15	14%
Average	**-**	**14%**

The reserve margin is particularly relevant to the calculation of uncleared capacity benefits. Uncleared measures are effectively “counted” on the demand side of the capacity auction (i.e., within the load forecast). In contrast, cleared measures are effectively treated the same as conventional power plants (i.e., supply), and through the auction effectively require the purchase of some extra amount of capacity to act as a reserve margin. As a result, we increase the uncleared capacity benefit by a value equal to one plus the reserve margin.

Calculating the benefit from uncleared capacity

Finally, to calculate the benefit from uncleared capacity in any particular year, we calculate the product of:

- The capacity price (e.g., the values in Table 40)
- The effect schedule that matches the measure's lifetime (e.g., the values in Table 43)
- One plus the reserve margin (e.g., the values in Table 44)

Table 45 describes the uncleared capacity benefit in Counterfactual #1. This table describes benefits for measures installed in 2021, with measure lives ranging from one to ten years.

Table 45. Uncleared capacity value for measures with L lifetimes installed in 2021 in Counterfactual #1 in rest-of-pool region

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
2021	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2023	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2024	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2025	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2026	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67
2027	$8.47	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17
2028	$9.02	$18.05	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58
2029	$9.83	$19.66	$29.49	$44.23	$44.23	$44.23	$44.23	$44.23	$44.23	$44.23
2030	$4.68	$14.03	$23.39	$32.74	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77
2031	$0.00	$5.02	$15.07	$25.12	$35.17	$50.24	$50.24	$50.24	$50.24	$50.24
2032	$0.00	$0.00	$5.34	$16.01	$26.69	$37.36	$53.38	$53.38	$53.38	$53.38
2033	$0.00	$0.00	$0.00	$5.28	$15.85	$26.42	$36.98	$52.83	$52.83	$52.83
2034	$0.00	$0.00	$0.00	$0.00	$6.39	$19.17	$31.95	$44.73	$63.90	$63.90
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$5.01	$15.02	$25.03	$35.04	$50.06
15-year levelized	**$2.92**	**$5.96**	**$9.12**	**$12.39**	**$15.74**	**$19.21**	**$22.36**	**$24.82**	**$26.66**	**$27.61**

Note: Note that effects for measures with measure lives of six years or greater continue to phase out after 2035. Because of this, the AESC 2021 User Interface (tab "Appdx J") calculates these effects through 2050 for each individual year, rather than extrapolating values. See the AESC 2021 User Interface for benefits in other counterfactuals, other regions, and benefits for measures with longer lifetimes.

Important caveats for applying uncleared capacity values

Uncleared capacity is different than many other avoided cost categories. Because uncleared capacity describes an effect that fades out over time due to the market's responses to that effect, users should sum avoided costs over the entire study period, regardless of any one measure's lifetime. For example, the avoided costs of a 1 MW measured installed in 2021 would be equal to the sum of the values from

2021 through 2055, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[156]

Uncleared resources affect the load forecast only to the degree that these resources provide load reductions on the hours used in the load forecast regression. Some resources—such as demand response resources—may be active only on one or some of the hours used in the load forecast. As a result, these resources would provide a diminished uncleared capacity benefit. We recommend that program administrators apply a scaling factor to the benefits detailed in Table 45 to account for this effect. See Appendix K: *Scaling Factor for Uncleared Resources* for more information on how this scaling factor is calculated and how it can be applied.

5.3. Other considerations

The following sections provide greater detail on other aspects of the capacity market assessed in AESC 2021.

ISO New England's Competitive Auctions with Sponsored Resources initiative

This section describes ISO New England's CASPR rule and how it is modeled in AESC 2021. This modeling is integral to the calculation of projected capacity supply, described above.

ISO New England has run two capacity auctions using a new method to allow some new resources sponsored by state policy to acquire capacity supply obligations without swamping the FCM. ISO New England's CASPR rule does not allow a new resource to bid into the capacity auctions at a price below its estimated cost, net of expected revenues from the ISO energy, capacity, and ancillary markets, plus revenues from RECs that are available to resources from a broad geographic and technology range. Any additional targeted revenues cannot be used to justify a lower bid price. This may include revenue from Massachusetts's SMART program for distributed solar; the Multi-State Clean Energy RFP (which has selected 246 MW of solar and 126 MW of wind projects to be divided among Massachusetts, Connecticut, and Rhode Island); or state-mandated contracts for purchases from Canada, offshore wind, or other renewables. As a result of CASPR, sponsored resources will often be unable to bid low enough to clear in the main auction, especially at the low prices observed in recent FCAs.

The CASPR solution treats the existing FCA as the first stage of a two-stage process. After the capacity supply obligations are determined in the primary auction, without participation of the sponsored resources, the ISO runs a substitution auction in which cleared generation resources can retire and buy out of their capacity supply obligations, by paying the sponsored renewable or green resources. For example, if an FCA clears at $4 per kW-month, a cleared generator might offer to pay up to $3 per kW-month to get out of a capacity supply obligation. The substitution auction may clear at $1 per kW-

[156] We note that this is the same approach used for summing avoided costs for uncleared capacity and uncleared capacity DRIPE, but no other avoided cost categories.

month, in which case the retiring generator will be paid \$4–\$1 = \$3 per kW-month for doing nothing in the delivery year. The substitution auction could even clear at a negative price, in which case the retiring resource would be paid more for not performing in the delivery year than for delivering capacity. The ISO considers the gain to the retiring generator a "severance payment" for giving up its place in the ISO markets.

The retiring resource must then give up its transmission interconnection rights and permanently retire from all ISO markets.[157] The substituted sponsored resource will be treated in the future as though it had cleared in the FCA, and it will be able to bid into future FCAs as an existing resource. The prospect of receiving capacity revenues for many years into the future may result in the sponsored resource bidding a substantial negative price in the substitution auction, such as paying \$5/kW-month for one year to receive future market prices indefinitely.

One effect of the CASPR rules will be to create incentives for marginally viable existing generators to bid in the FCA with the intention of selling the capacity supply obligation in the substitution auction. As a result, most existing capacity supply obligations from transmission-connected generators may never retire, since they can be profitably transferred to sponsored resources.

Through FCA 14, sponsored renewables were able to qualify under a temporary exception to the minimum bid limits, known as the Renewable Technology Rule. The exception was removed in FCA 15, after which new sponsored resources with need to acquire capacity obligations in the CASPR secondary auction.

We model CASPR by treating CASPR-eligible resources (such as wind and solar) separately within our capacity model. We first assess the incremental year-on-year firm capacity of these resources, then determine whether or not there is sufficient retiring capacity in that same year. If yes, capacity from these resources is deemed eligible for the main capacity market and is added to the overall calculation of supply.

Other capacity-related avoided costs

In addition to the locational marginal energy prices and capacity prices, ISO New England's monthly *Wholesale Load Cost Report* includes the following cost components:

- First-Contingency Net Commitment Period Compensation (NCPC)
- Second-Contingency NCPC
- Regulation (automatic generator control)
- Forward Reserves

[157] Only existing generation resources with transmission interconnection rights are able to discharge their capacity supply obligations in the substitution auction.

- Real-Time Reserves
- Inadvertent Energy
- Marginal Loss Revenue Fund
- Auction Revenue Rights revenues
- Price Responsive Demand Cost
- ISO Tariff Schedule 2 Expenses
- ISO Tariff Schedule 3 Expenses
- NEPOOL Expenses

These cost components are described in more detail in the *Wholesale Load Cost Reports*.[158] For 2019, ISO New England's estimates of costs to load (a load with 100 percent load factor) for most zones comprised energy (about 70 percent of the total) and capacity costs (about 26 percent) as well as a few percent for all of the NCPC, reserves, and regulation put together. These ratios will change over time, for example, as capacity prices fall.

None of the components listed below vary clearly enough with the level of load to warrant inclusion in the avoided-cost computation. More specifically:

- The **NCPC costs** (by far the largest of these categories, although much smaller than forward capacity charges) are compensation to generators that comply with ISO instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Lower on-peak loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices (especially off-peak) would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.

- **Regulation costs** are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency

[158] ISO New England. Last accessed March 11, 2021. "Energy, load, and Demand Reports." *EPA.gov.* Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/mthly-whl-load-cost-rpt.

programs will probably reduce regulation costs, but we cannot estimate the magnitude of the effect.

- **Forward and real-time reserve requirements** should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more available capacity on transmission lines, which will tend to reduce the need for local reserves. Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.

- **Inadvertent energy exchanges** with other system operators (NYISO, Hydro Québec, and New Brunswick) are small and probably not affected by energy efficiency.

- The **Marginal Loss Revenue Fund** returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by infra-marginal usage, and it will not be affected by reduction of loads at the margin.

- **Auction Revenue Right** revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.

- **Price Responsive Demand** charges recover a portion of the ISO's payments for those demand resources. The use of those resources would tend to fall as peak prices fall, but so would their compensation from the energy markets, potentially increasing this charge. This category is miniscule.

Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow to occur, and energy efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the FCM.

6. AVOIDED ENERGY COSTS

This chapter describes the findings associated with avoided energy costs. As a point of comparison, we compare the electric energy prices for the West Central Massachusetts zone between AESC 2021 and AESC 2018.[159] On a levelized basis, the 15-year AESC 2021 annual all-hours price for Counterfactual #1 is $41 per MWh, compared to the equivalent value of $51 per MWh from AESC 2018. This represents a reduction of 20 percent. For Counterfactual #2, the 15-year AESC 2021 annual all-hours price is $38 per MWh, representing a reduction of 26 percent relative to the value from AESC 2018. Counterfactual #3 and #4 both feature 15-year AESC 2021 annual all-hours prices of $41 per MWh, a 19 percent reduction relative to AESC 2018.[160] The decrease in energy prices observed in AESC 2021 is primarily due to a lower estimate of wholesale natural gas prices in New England and a lower estimate of RGGI prices.

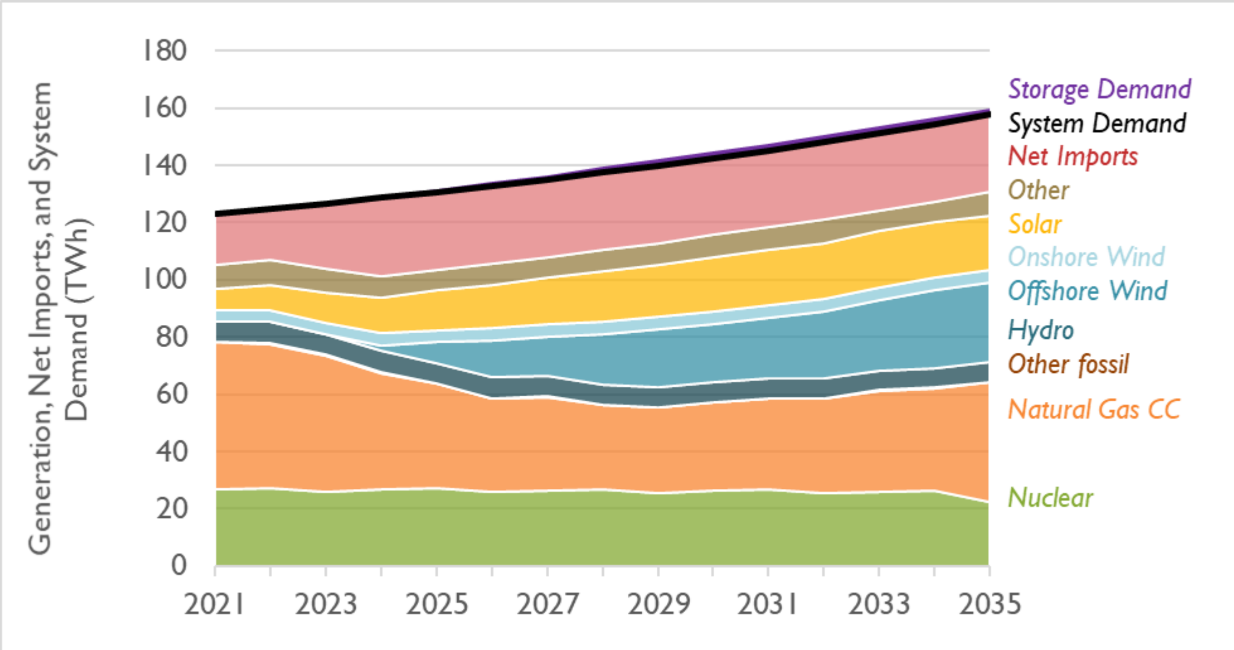
6.1. Forecast of energy and energy prices

Figure 38 presents the projected level of New England electric system energy from 2021 to 2035. These energy levels are estimated by the EnCompass model given the capacities specified in Figure 39, fuel prices, availability factors, heat rates, and other unit attributes. Figure 38 assumes a future in which no new energy efficiency is added in 2021 or later years, and other assumptions are consistent with Counterfactual #1. This figure includes an accounting of energy imports over both existing and new transmission lines from electric regions adjacent to New England. Note that all prices discussed in this chapter are wholesale prices, not retail prices.

[159] This WCMA price is intended to represent the ISO New England Control Area price, which is within this zone.

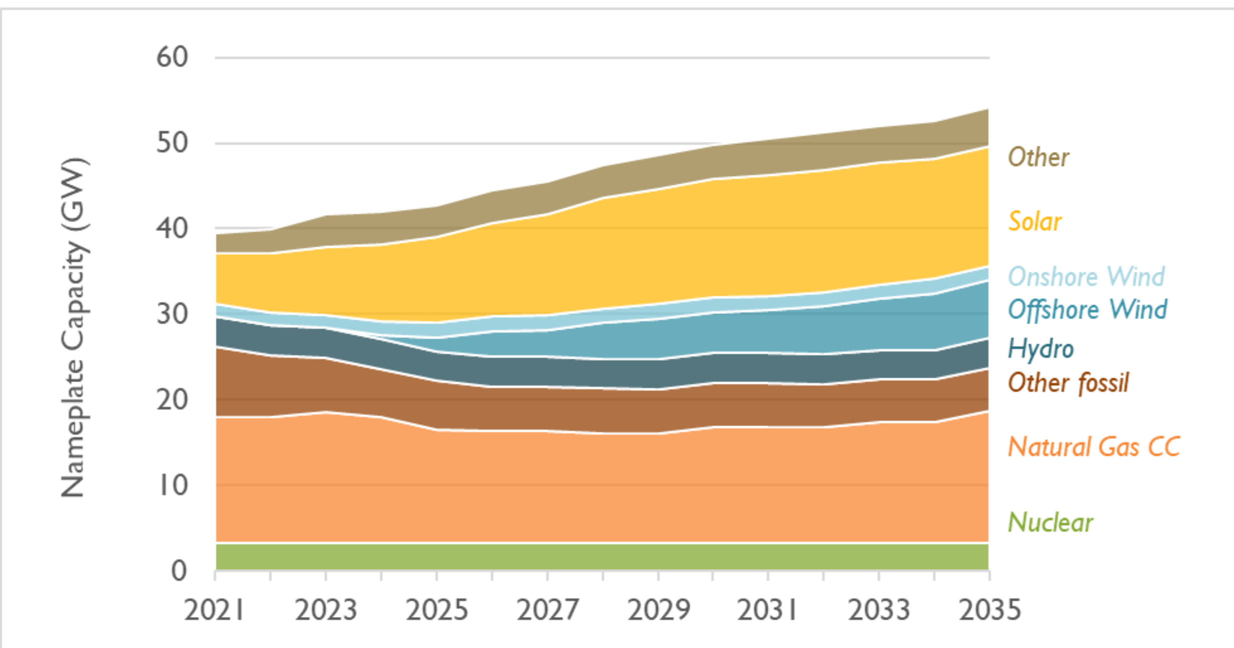
[160] The difference in percentage change relative to Counterfactual #1 is a result of rounding.

Figure 38. AESC 2021 New England-wide generation, imports, and system demand in Counterfactual #1



Notes: "Other Fossil" contains generation from steam turbines (including coal), combustion turbines, fuel cells, and other miscellaneous fossil fuel-fired power plants. "Other" contains generation from energy storage, demand response, municipal solid waste, landfill gas, and other miscellaneous fuel types.

Figure 39. New England-wide capacity modeled in EnCompass in Counterfactual #1



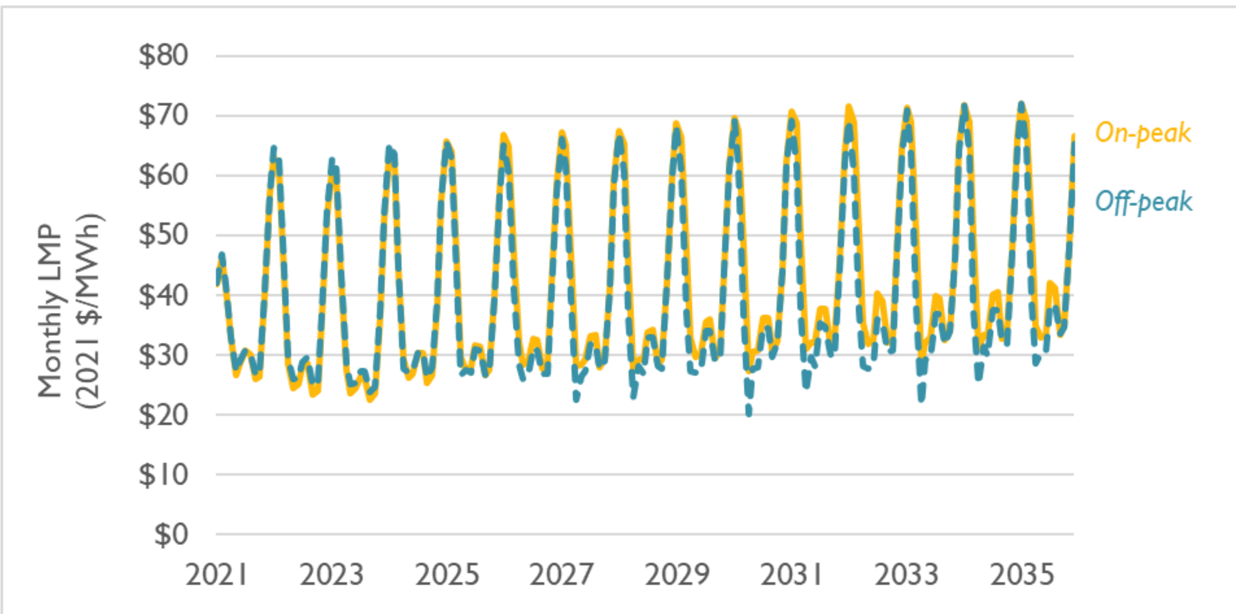
Notes: "Other Fossil" contains capacity associated with steam turbines (including coal), combustion turbines, fuel cells, and other miscellaneous fossil fuel-fired power plants. "Other" contains capacity associated with energy storage, demand response, municipal solid waste, landfill gas, and other miscellaneous fuel types. Capacity is included in the above chart in a given year if a resource is existing on January 1 of that year.

Forecast of wholesale energy prices

In addition to modeling the generation shown in Figure 39, the EnCompass model also produces wholesale energy prices (see Figure 40 and Table 46).[161] These modeled prices change over time (and on a peak and off-peak basis) depending on the system demand, available units, transmission constraints, fuel prices, and other attributes. This trend is caused by (a) increasing amounts of renewable and imported generation which increasingly displaces higher-cost fossil units, and (b) a lower future Algonquin basis in real-dollar terms, in some months. Year-to-year variations in prices can be traced to impacts associated with the new transmission line from Canada in the early 2020s, large quantities of offshore wind in the mid to late 2020s, a flattening of assumed Henry Hub prices in real-dollar terms through the 2030s, and lower RGGI prices.[162]

Note that these energy prices are not inclusive of RECs, but they are inclusive of modeled environmental regulations that impose a price on traditional generators, including RGGI and 310 CMR 7.74.

Figure 40. AESC 2021 wholesale energy price projection for WCMA in Counterfactual #1



Note: As elsewhere in this report, in this figure, on-peak and off-peak are defined according to ISO New England's definitions, and may not match popular conceptions of on-peak or off-peak. See Appendix B: Detailed Electric Outputs for more information on this topic.

[161] Note that all summarized energy prices are calculated using a load-weighted average.

[162] Note that modeled energy prices described here do not include impacts from ISO New England's proposed Energy Security Initiative (ESI) which was rejected by FERC in October 2020.

Table 46. AESC 2021 wholesale energy price projection for WCMA region in Counterfactual #1 (2021 $ per MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
2021	$36.05	$42.85	$36.72	$31.93	$26.26
2022	$37.61	$45.03	$41.65	$28.79	$25.30
2023	$36.61	$43.18	$42.03	$26.19	$25.06
2024	$39.05	$45.30	$44.19	$29.39	$27.84
2025	$39.56	$45.69	$44.61	$30.23	$28.35
2026	$39.94	$46.69	$44.26	$31.50	$27.97
2027	$40.12	$47.43	$43.35	$32.90	$27.77
2028	$40.49	$45.79	$45.45	$31.62	$30.45
2029	$41.80	$46.95	$47.18	$32.77	$31.46
2030	$41.99	$46.97	$47.04	$33.46	$31.98
2031	$42.86	$47.91	$47.92	$34.52	$32.47
2032	$43.74	$50.30	$47.22	$37.19	$31.48
2033	$44.04	$49.72	$47.97	$36.93	$33.15
2034	$44.73	$49.65	$49.59	$36.57	$34.69
2035	$45.57	$50.49	$50.43	$37.52	$35.35

Comparison to AESC 2018

Table 47 shows a comparison between AESC 2018 and AESC 2021 for the 15-year levelized costs for the WCMA reporting region. Prices are shown for all hours, and for the four periods analyzed in previous AESC studies. On an annual average basis, the Counterfactual #1 15-year levelized prices in the AESC 2021 Study are 20 percent lower than the prices modeled in the AESC 2018 Study, while the Counterfactual #2 15-year levelized prices are 26 percent lower. Counterfactual #3 and #4 both show levelized prices that are 19 percent lower than the prices modeled in the AESC 2018 Study. Key drivers of these lower prices include lower overall demand for electricity (even in a future with no incremental energy efficiency), lower Henry Hub natural gas prices, lower RGGI prices, more renewables (caused by changes to renewable policies in several states), and the addition of a new transmission line from Canada.[163] This decrease is larger than the change in avoided energy costs observed between the AESC 2015 Study and the AESC 2018 Study.

In particular, AESC 2021 modeling results feature a lower ratio of summer peak prices to the annual average than observed in previous AESC studies. This difference can be attributed to: (1) increased levels of solar generation, which is largely coincident with this period and which have a marginal cost of zero dollars per MWh, (2) difference in summer wholesale gas costs (which are driven by new recent historical data on month-to-month gas costs), and (3) higher levels of zero-marginal cost imports. These are the same factors that drove the change in energy prices from AESC 2015 and AESC 2018. Meanwhile, the ratio of winter peak prices to annual average prices are largely unchanged, relative to AESC 2018.

[163] Other factors, including the Massachusetts-specific emissions cap under MA DEP 310 CMR 7.74 and a lower discount rate, push the avoided costs observed in AESC 2018 up, but not enough to overcome the impact of the other factors mentioned above.

This is due to largely consistent assumptions on winter gas costs (relative to annual averages) and similar load shapes.

Among the counterfactuals, prices are generally similar due to the relatively flat supply curve for energy in New England. In other words, the region has a large number of relatively new, similar, natural gas-fired combined cycle units that are frequently marginal in any future year, in any future counterfactual. That said, Counterfactual #2 does feature lower prices compared to the other two counterfactuals due to lower system loads and lower peak demand.[164]

Table 47. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	$51.17	$58.66	$54.17	$45.22	$38.69
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
AESC 2021 Counterfactual 4	$41.29	$47.40	$45.62	$33.17	$29.87
% Change: Counterfactual 1	-20%	-20%	-17%	-28%	-23%
% Change: Counterfactual 2	-26%	-27%	-23%	-32%	-28%
% Change: Counterfactual 3	-19%	-19%	-16%	-26%	-23%
% Change: Counterfactual 4	-19%	-19%	-16%	-27%	-23%

Notes: All prices have been converted to 2021 $ per MWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. AESC 2018 values are from AESC 2018 Chapter 5 and the AESC 2021 User Interface.

Table 48 compares 15-year levelized costs between AESC 2018 and AESC 2021 for each of the six New England states. These values incorporate the relevant costs of RPS compliance, as well as the impact of wholesale risk premiums. Avoided energy costs for each reporting region are detailed in Appendix B: *Detailed Electric Outputs*.

[164] These results are consistent with the “With EE” sensitivity modeled in AESC 2018.

Table 48. Avoided energy costs, AESC 2021 vs. AESC 2018 (15-year levelized costs, 2021 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	1	Connecticut	$0.059	$0.057	$0.043	$0.040
	2	Massachusetts	$0.062	$0.060	$0.047	$0.044
	3	Maine	$0.057	$0.056	$0.042	$0.039
	4	New Hampshire	$0.058	$0.057	$0.043	$0.040
	5	Rhode Island	$0.065	$0.064	$0.050	$0.047
	6	Vermont	$0.054	$0.053	$0.039	$0.036
AESC 2018	1	Connecticut	$0.063	$0.059	$0.049	$0.043
	2	Massachusetts	$0.062	$0.058	$0.049	$0.043
	3	Maine	$0.058	$0.054	$0.045	$0.039
	4	New Hampshire	$0.063	$0.060	$0.051	$0.044
	5	Rhode Island	$0.061	$0.057	$0.048	$0.042
	6	Vermont	$0.062	$0.058	$0.049	$0.042
Delta	1	Connecticut	-$0.005	-$0.002	-$0.006	-$0.003
	2	Massachusetts	-$0.001	$0.003	-$0.002	$0.001
	3	Maine	$0.000	$0.002	-$0.003	$0.000
	4	New Hampshire	-$0.005	-$0.003	-$0.008	-$0.004
	5	Rhode Island	$0.003	$0.007	$0.002	$0.005
	6	Vermont	-$0.008	-$0.005	-$0.010	-$0.006
Percent Difference	1	Connecticut	-7%	-3%	-12%	-7%
	2	Massachusetts	-1%	5%	-4%	2%
	3	Maine	0%	4%	-6%	1%
	4	New Hampshire	-8%	-5%	-15%	-8%
	5	Rhode Island	6%	12%	5%	12%
	6	Vermont	-13%	-8%	-20%	-14%

Notes: These costs are the sum of wholesale energy costs and wholesale costs of RPS compliance, increased by a wholesale risk premium of 8 percent, except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2021 dollars per kWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2018. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Values do not include losses.

6.2. Benchmarking the EnCompass energy model

The AESC 2021 Study Group required a calibration of the dispatch model used with actual, historical data. To complete this, the Synapse Team developed modeling inputs that reflect our best understanding of electric system market operations in 2019. This included assumptions relating to available generating units, fuel prices, and system demand.

Figure 41 compares actual day-ahead locational marginal prices (LMP) for each New England region reported on by ISO New England against the same prices modeled in EnCompass for 2019.[165] This figure also details the percent difference between actual and modeled LMPs for each region. For the WCMA region, for example, average modeled LMPs for 2019 are 3 percent higher than actual historical LMPs. For all regions, modeled 2019 LMPs range from 1 percent higher to 3 percent higher than actual 2019 LMPs.

Figure 41. Comparison of 2019 historical and simulated 2019 locational marginal prices

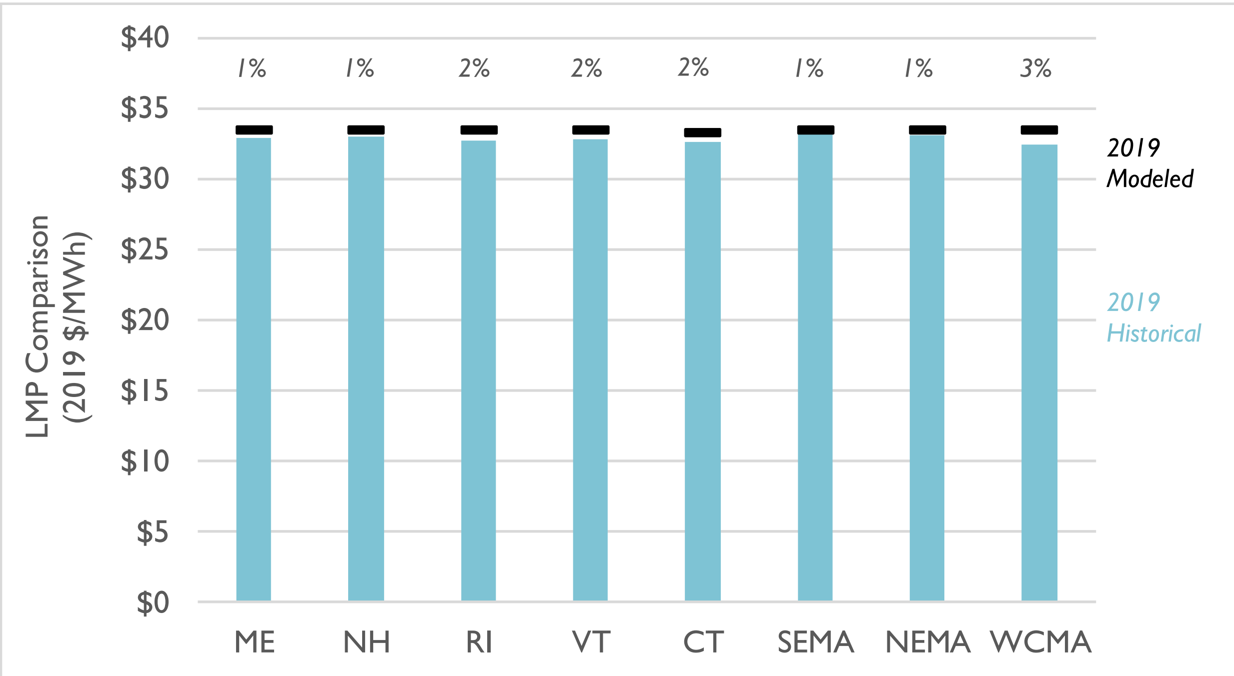


Figure 42 compares the monthly modeled LMPs for 2019 in the WCMA region against actual 2019 LMPs for the same region, and Figure 43 compares hourly modeled New England-wide average LMPs for 2019 against actual hourly 2019 LMPs for New England.[166] Our calibration for 2019 produces differences between modeled results and actual historical prices in line with the differences observed between a calibrated 2016 year from the 2018 AESC study. The scale of these differences indicates that the EnCompass model is accurately capturing the magnitude and differential spread of LMPs around New England during 2019. As in previous AESC studies, differences between price on a regional or temporal basis—for both the annual, monthly, and hourly calibrations—are likely related to differences between actual anomalies in the electric system (which are challenging to represent in an electric system dispatch

[165] Actual LMP data is available from the ISO New England website at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[166] Note that the prices modeled in EnCompass most closely approximate day-ahead, rather than real-time prices. The day-ahead market is where most of the generating fleet is committed and compensated, whereas the real-time market mostly represents transfer payments for over-performance and under-performance; they do not necessarily approximate the price implied by the hour-by-hour demand.

model) and the production cost model's best-estimate rendering of a historical year. These "anomalies" may include actual and assumed generator and transmission outages (for which hourly data is unavailable or difficult to access), maintenance schedules (which are plant-specific and typically unknown), and operator discretion (which is often masked by ISO New England for confidentiality purposes). These differences may imply that depending on variations in future years, some hourly avoided costs may be underestimated while some others will be overestimated.

Figure 42. Comparison of 2019 historical and simulated 2019 locational marginal prices for the WCMA region (monthly)

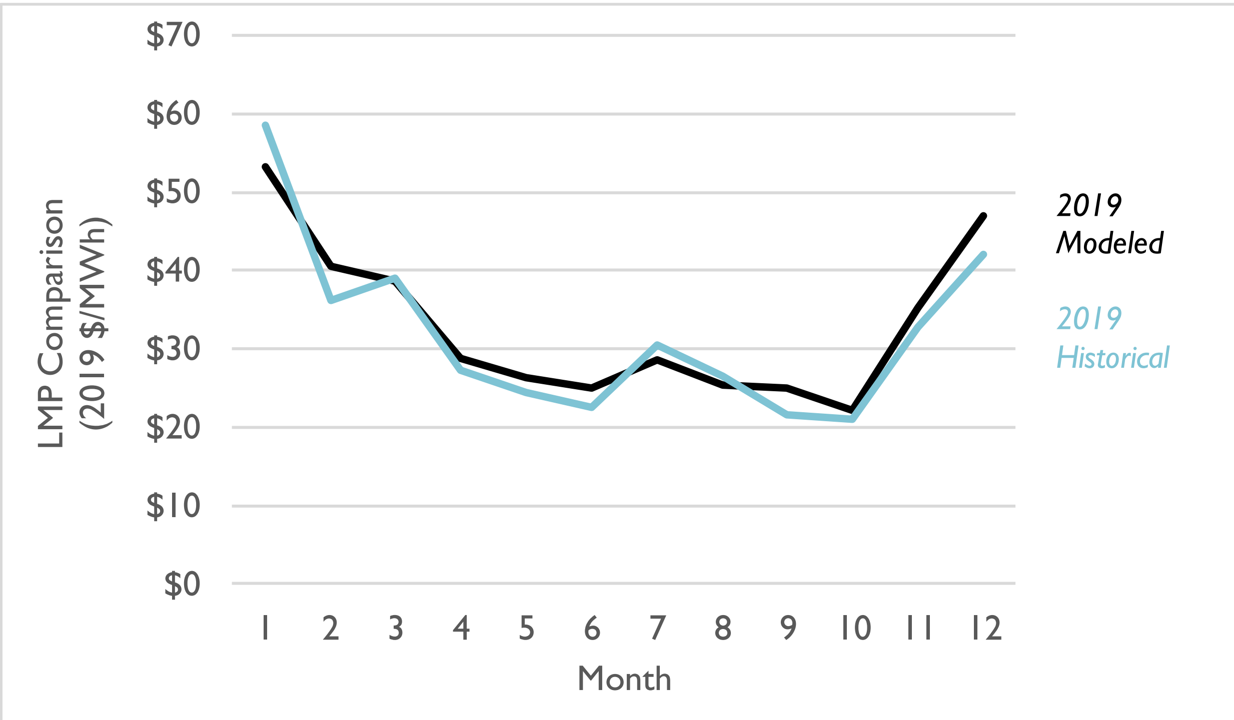
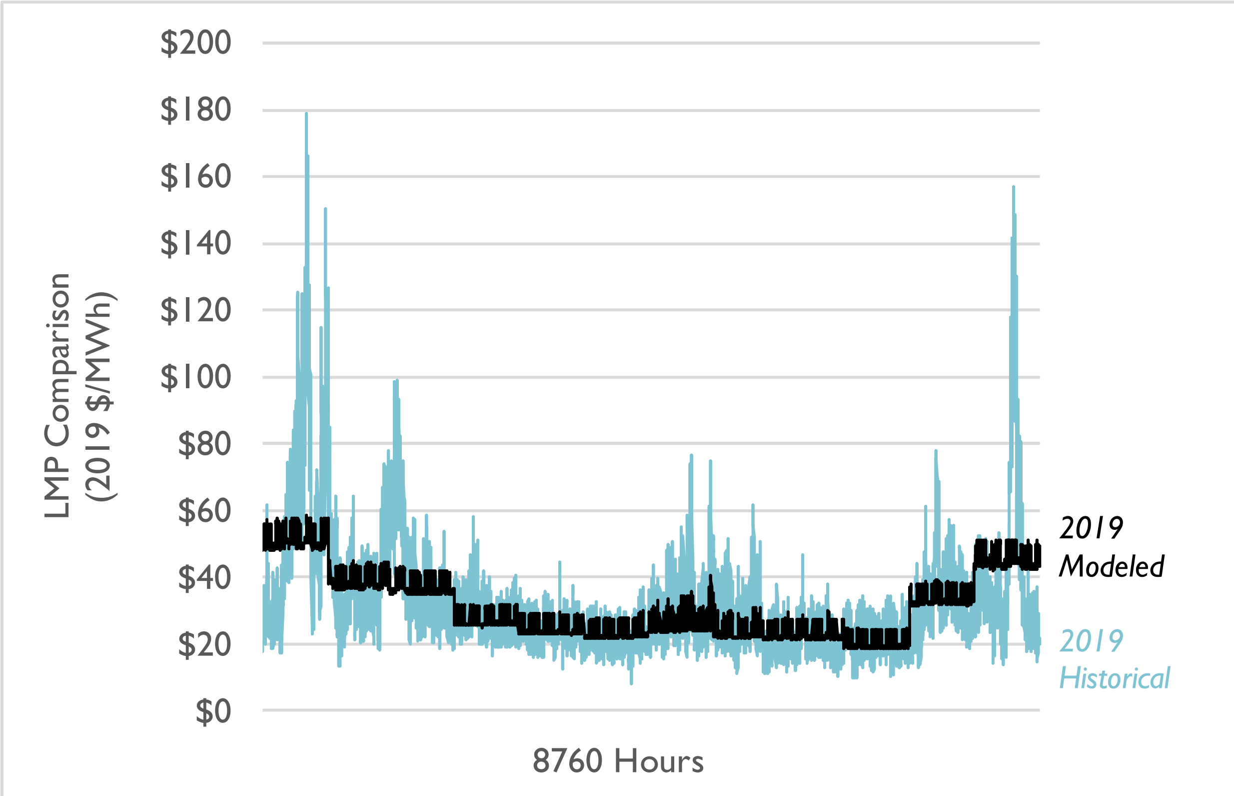


Figure 43. Comparison of 2019 historical and simulated 2019 locational marginal prices for New England (hourly)



7. Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies

Energy efficiency programs reduce the cost of compliance with RPS requirements by reducing total LSE load. Reduction in load due to energy efficiency or other demand-side resources will therefore reduce the RPS obligations of LSEs and the associated compliance costs recovered from consumers. This estimate of avoided costs includes the expected impact of avoiding each class or tier[167] of RPS[168] or Renewable Energy Standards[169] (RES) within each of the six New England states. Table 49, Table 50, Table 51, and Table 52 list the avoided costs of compliance for Counterfactuals #1, #2, #3, and #4, respectively.[170] Generally speaking, avoided costs are lowest in Counterfactual #2. Avoided costs are higher in Counterfactual #1 as a result of increased load and increased demand for RECs. Avoided costs are highest in Counterfactual #3 and #4, which feature the same set of avoided costs and have the highest loads (as they both ignore any energy efficiency added in 2021 or later, but also model additional load from building electrification).

Table 49. Avoided cost of RPS compliance for Counterfactual #1 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**

Table 50. Avoided cost of RPS compliance for Counterfactual #2 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.43	$3.10	$3.10	$1.31	$5.62	$0.75
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**

Table 51. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

[167] Vermont uses the term “tier” while all other New England states use the term “class” to describe RPS categories.

[168] Massachusetts, Connecticut, Maine, and New Hampshire use the term Renewable Portfolio Standard (RPS).

[169] Rhode Island and Vermont use the term Renewable Energy Standard (RES).

[170] All values are levelized over 15 years and include energy losses.

Table 52. Avoided cost of RPS compliance for Counterfactual #4 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS percentage target. That incremental unit cost is the price of a REC. The avoided cost of RPS compliance is not equal to the REC price, however. Instead, the avoided cost is a function of both REC price and load obligation percentage (i.e., the RPS target percentage). Therefore, the state with the highest or lowest REC price does not necessarily have the highest or lowest compliance cost because of the multiplicative impact of the RPS target.

Table 53 shows that avoided costs projected in AESC 2021 are generally higher than those projected in AESC 2018. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification. Increases in the cost of RPS compliance in states that have not increased RPS targets (e.g., New Hampshire) are due to an increase in REC demand in the New England-wide REC market, of which all six states are participants.

Table 53. Avoided costs in AESC 2018 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.00	$0.22	$1.83	$1.61	$2.54	$0.56
MA CES	-	-	$0.48	-	-	-
All Other Classes	$1.00	$0.33	$1.53	$3.65	$0.03	$1.55
Total	**$4.00**	**$0.55**	**$3.84**	**$5.25**	**$2.57**	**$2.12**

Notes: Values have been converted from 2018 dollars to 2021 dollars. All values shown use a 9 percent loss factor, consistent with AESC 2021, rather than the 8 percent loss factor used in AESC 2018.

7.1. Assumptions and methodology

The purpose of this section is to describe the assumptions and methodology for forecasting the avoided cost of RPS and Massachusetts CES and CPS compliance. REC price forecasts are developed for each RPS sub-category and are based on expectations regarding eligible supply, annual demand targets, and—where applicable—the long-term cost of entry of renewable energy additions. These forecasts are converted to an avoided cost of RPS, CES, and CPS compliance on a dollar per MWh basis. Voluntary demands for Class 1 RECs (such as a portion of corporate renewable energy purchases and community choice aggregation) are also taken into account as a factor influencing Class 1 REC prices.

Renewable portfolio standards and clean energy standards

All six New England states have active RPS or RES policies—referred to hereafter as RPS. Each RPS program has multiple classes—referred to as tiers in Vermont—which are used to differentiate these policy mandates by technology, vintage, emissions, and other criteria that reflect state-specific policy objectives. Massachusetts also has a CES, which is met in large part by the MA Class I RPS obligation. It also has a "CES-E" for existing non-emitting resources—specifically nuclear and hydroelectric facilities from New Hampshire, Connecticut, and eastern Canada. Finally, Massachusetts regulations also include an Alternative Energy Portfolio Standard (APS), which applies to combined heat and power, renewable thermal, flywheel storage, fuel cells, and waste-to-energy, and increases by 0.25 percent per year indefinitely. While largely supporting non-renewable resources, APS program targets and avoided cost are nonetheless included in this section because the mandate is avoided by energy efficiency in the same manner as the RPS. Table 54 provides a summary overview of RPS and CES obligations throughout New England. Maine Class IA and MA CES-E are new policy additions since AESC 2018.

Regional Class I requirements (as well as Class II in New Hampshire and Tier II in Vermont) are intended to create demand for new renewable energy additions. As a result, the RPS targets for these classes increase each year until a specified maximum obligation is attained. Massachusetts Class I is the notable exception to this rule; it increases indefinitely—presumably until the sum of all RPS and CES mandates reaches 100 percent. Class II,[171] Class III, Class IV, and other "existing" supply obligations focus on generators that were already in operation prior to the adoption of RPS programs. These policies are intended to maintain the pre-RPS fleet rather than spur the development of new generating facilities. As a result, the RPS targets for these classes do not generally increase each year, although some are subject to periodic adjustment based either on supply conditions or policymaker discretion. The percentage targets for each class are summarized below in Table 55 and Table 56.

[171] With the exception of NH-II (which is dedicated to "new" solar) and possibly CT-II (which is dedicated to waste-to-energy and is without a vintage requirement).

Table 54. Summary of RPS and CES classes

State	RPS Class or Tier	COD Threshold	Eligibility Notes
Connecticut	Class I	No threshold	Subject to emissions threshold
	Class II	No threshold	Dedicated to WTE; Class I resources also eligible
	Class III	No threshold	Conservation and load management resources
Maine	Class I	Beginning 9/1/2005	Allows refurbished facilities
	Class IA	Beginning 9/1/2005	Does not allow refurbished facilities
	Class II	Before 9/1/2005	Allows hydro up to 100 MW
Massachusetts	Class I	Beginning 1/1/1998	Includes two solar carve-outs
	Class II-Non-WTE	Before 1/1/1998	Includes same biomass standards as Class I
	Class II-WTE	Before 1/1/1998	Dedicated class for waste-to-energy
	APS	Beginning 1/1/2008	Combined heat and power, useful thermal energy
	CES	Beginning 1/1/2011	MA Class I certified resources also eligible
	CES-E	Before 1/1/2011	Nuclear & hydro from NH, CT & eastern Canada
	CPS	No threshold	New MA-1, existing MA-1 w/ storage, DRR
New Hampshire	Class I	Beginning 1/1/2006	Includes a thermal carve-out
	Class II	Beginning 1/1/2006	Solar only
	Class III	Before 1/1/2006	Dedicated to biomass and LFG
	Class IV	Before 1/1/2006	Small hydro only
Rhode Island	New	Beginning 1/1/1998	Fuel standard requirements apply
	Existing	Before 1/1/1998	Fuel standard requirements apply
Vermont	Tier I	No threshold	Class II and RE portion of imports also eligible
	Tier II	Beginning 1/1/2015	Must be in-state and < 5 MW
	Tier III	Beginning 1/1/2015	Class II resources also eligible

Notes: The COD threshold is the date after which a project must have commenced commercial operation in order to be eligible. For the Massachusetts CES, eligible projects must have a COD on or after 1/1/2011; eligible facilities from adjacent control areas must be delivered over transmission energized on or after 1/1/2017. "DRR" are Demand Response Resources; for more information, see https://www.mass.gov/service-details/program-summaries.

In addition to distinguishing between new and existing supply, some New England RPS programs also include specified sub-component requirements for solar, biomass, hydroelectric, combined heat and power, waste-to-energy, thermal resources, energy transformation, or energy efficiency. These classes are also included in Table 54 and their respective targets are summarized in Table 56. For simplicity, this discussion includes these obligations under "RPS and CES requirements," even though some classes include resources that are not renewable.

RPS and CES compliance assumptions

AESC 2021 assumes that each retail LSE complies with RPS and CES obligations, by class and by state, in each calendar year—either by securing certified RECs or by making ACPs to the applicable regulatory authority. RPS requirements are calculated by multiplying obligated load[172] (adjusted for contract exemptions) by the applicable annual class-specific RPS percentage target. The forecast of obligated load is based on the aggregate impact of econometric load, energy efficiency, active demand response, and electrification described in Section 4.3: *New England system demand*. This includes a detailed forecast of BTM generation, which is critical because it both reduces obligated load and generates RECs for RPS compliance.[173] In all states, RPS targets are defined as a percentage of obligated load. Table 55 summarizes RPS targets for new renewable energy additions, while Table 56 summarizes RPS targets for existing resource categories. Beginning in 2025, MA Class I targets are based on legislative proposals expected to pass during the 2020 session. The Massachusetts legislature is also considering a "Greenhouse Gas Emissions Standard" (GGES) for municipal utilities. The GGES is expected to create incremental demand for new renewable capacity beginning 2024. Beginning in 2022, RI "New" targets are assumed to align with Executive Order 20-01 and *The Road to 100% Renewable Electricity by 2030 in Rhode Island* report, which calls for 100 percent renewable electricity by 2030. All other targets reflect current statutes.

[172] Municipal utilities are currently exempted from RPS and CES obligations in all states except Vermont. These exemptions are assumed to remain for the duration of the study period.

[173] Several states have begun to consider whether load offset by BTM generation should be added to the total RPS obligation. These discussions are preliminary, however, and therefore not included in this analysis.

Table 55. Summary of modeled RPS targets for new resource categories

	CT-I	ME-I	ME-IA	MA-I[174]	MA-SREC-I[175]	MA-SREC-II[176]	MA CPS (est.)	MA APS	NH-I[177]	NH-I Thermal	NH-II	RI-New	VT-II
2021	22.5%	10%	5%	18%	1.66%	3.92%	3.0%	5.25%	11.4%	1.8%	0.7%	15.5%	3.4%
2022	24%	10%	8%	20%	TBD	TBD	4.5%	5.50%	12.3%	2.0%	0.7%	24.7%	4.0%
2023	26%	10%	11%	22%	TBD	TBD	6.0%	5.75%	13.2%	2.2%	0.7%	33.8%	4.6%
2024	28%	10%	15%	24%	TBD	TBD	7.5%	6.00%	14.1%	2.2%	0.7%	43%	5.2%
2025	30%	10%	19%	27%	TBD	TBD	9.5%	6.25%	15%	2.2%	0.7%	52.2%	5.8%
2026	32%	10%	23%	30%	TBD	TBD	11.75%	6.50%	15%	2.2%	0.7%	61.3%	6.4%
2027	34%	10%	27%	33%	TBD	TBD	13.75%	6.75%	15%	2.2%	0.7%	70.5%	7.0%
2028	36%	10%	31%	36%	TBD	TBD	15.25%	7.00%	15%	2.2%	0.7%	79.7%	7.6%
2029	38%	10%	35%	39%	TBD	TBD	16.75%	7.25%	15%	2.2%	0.7%	88.8%	8.2%
2030	40%	10%	40%	40%	TBD	TBD	18.25%	7.50%	15%	2.2%	0.7%	98%	8.8%
2031	40%	10%	40%	41%	TBD	TBD	19.75%	7.75%	15%	2.2%	0.7%	98%	9.4%
2032	40%	10%	40%	42%	TBD	TBD	21.25%	8.00%	15%	2.2%	0.7%	98%	10%
2033	40%	10%	40%	43%	TBD	TBD	22.75%	8.25%	15%	2.2%	0.7%	98%	10%
2034	40%	10%	40%	44%	TBD	TBD	24.25%	8.50%	15%	2.2%	0.7%	98%	10%
2035	40%	10%	40%	45%	TBD	TBD	25.75%	8.75%	15%	2.2%	0.7%	98%	10%
2036	40%	10%	40%	46%	TBD	TBD	TBD	9.00%	15%	2.2%	0.7%	98%	10%
2037	40%	10%	40%	47%	TBD	TBD	TBD	9.25%	15%	2.2%	0.7%	98%	10%
2038	40%	10%	40%	48%	TBD	TBD	TBD	9.50%	15%	2.2%	0.7%	98%	10%
2039	40%	10%	40%	49%	TBD	TBD	TBD	9.75%	15%	2.2%	0.7%	98%	10%
2040	40%	10%	40%	50%	TBD	TBD	TBD	10.00%	15%	2.2%	0.7%	98%	10%
2041	40%	10%	40%	51%	TBD	TBD	TBD	10.25%	15%	2.2%	0.7%	98%	10%
2042	40%	10%	40%	52%	TBD	TBD	TBD	10.50%	15%	2.2%	0.7%	98%	10%
2043	40%	10%	40%	53%	TBD	TBD	TBD	10.75%	15%	2.2%	0.7%	98%	10%
2044	40%	10%	40%	54%	TBD	TBD	TBD	11.00%	15%	2.2%	0.7%	98%	10%
2045	40%	10%	40%	55%	TBD	TBD	TBD	11.25%	15%	2.2%	0.7%	98%	10%
2046	40%	10%	40%	56%	TBD	TBD	TBD	11.50%	15%	2.2%	0.7%	98%	10%
2047	40%	10%	40%	57%	TBD	TBD	TBD	11.75%	15%	2.2%	0.7%	98%	10%
2048	40%	10%	40%	58%	TBD	TBD	TBD	12.00%	15%	2.2%	0.7%	98%	10%
2049	40%	10%	40%	59%	TBD	TBD	TBD	12.25%	15%	2.2%	0.7%	98%	10%
2050	40%	10%	40%	60%	TBD	TBD	TBD	12.50%	15%	2.2%	0.7%	98%	10%

Notes: The modeling horizon of AESC 2021 is through 2035; percentage targets are shown through 2050 for reference.

174 This is the gross MA-I target. The MA-SREC target is carved out of the MA-I target.

175 Without exemptions for load under contract.

176 Without exemptions for load under contract.

177 This is the gross NH-I target. The NH-I Thermal target is carved out of the NH-I target.

Table 56. Summary of RPS targets for other resource categories

	CT-II[a]	CT-III	ME-II	MA-II Non-WTE	MA-II WTE	MA CES	MA CES-E[b]	NH-III[c]	NH-IV	RI-Existing	VT-I[d]	VT-III
2021	4%	4%	30%	3.56%	3.5%	22%	20%	8%	1.5%	2%	55.6%	4.67%
2022	4%	4%	30%	3.6%	3.5%	24%	20%	8%	1.5%	2%	55%	5.33%
2023	4%	4%	30%	TBD	3.5%	26%	20%	8%	1.5%	2%	58.4%	6.00%
2024	4%	4%	30%	TBD	3.5%	28%	20%	8%	1.5%	2%	57.8%	6.67%
2025	4%	4%	30%	TBD	3.5%	30%	20%	8%	1.5%	2%	57.2%	7.33%
2026	4%	4%	30%	TBD	3.5%	32%	20%	8%	1.5%	2%	60.6%	8.00%
2027	4%	4%	30%	TBD	3.5%	34%	20%	8%	1.5%	2%	60%	8.67%
2028	4%	4%	30%	TBD	3.5%	36%	20%	8%	1.5%	2%	59.4%	9.33%
2029	4%	4%	30%	TBD	3.5%	38%	20%	8%	1.5%	2%	62.8%	10.0%
2030	4%	4%	30%	TBD	3.5%	40%	20%	8%	1.5%	2%	62.2%	10.67%
2031	4%	4%	30%	TBD	3.5%	42%	20%	8%	1.5%	2%	61.6%	11.33%
2032	4%	4%	30%	TBD	3.5%	44%	20%	8%	1.5%	2%	65%	12.0%
2033	4%	4%	30%	TBD	3.5%	46%	20%	8%	1.5%	2%	65%	12.0%
2034	4%	4%	30%	TBD	3.5%	48%	20%	8%	1.5%	2%	65%	12.0%
2035	4%	4%	30%	TBD	3.5%	50%	20%	8%	1.5%	2%	65%	12.0%
2036	4%	4%	30%	TBD	3.5%	52%	20%	8%	1.5%	2%	65%	12.0%
2037	4%	4%	30%	TBD	3.5%	54%	20%	8%	1.5%	2%	65%	12.0%
2038	4%	4%	30%	TBD	3.5%	56%	20%	8%	1.5%	2%	65%	12.0%
2039	4%	4%	30%	TBD	3.5%	58%	20%	8%	1.5%	2%	65%	12.0%
2040	4%	4%	30%	TBD	3.5%	60%	20%	8%	1.5%	2%	65%	12.0%
2041	4%	4%	30%	TBD	3.5%	62%	20%	8%	1.5%	2%	65%	12.0%
2042	4%	4%	30%	TBD	3.5%	64%	20%	8%	1.5%	2%	65%	12.0%
2043	4%	4%	30%	TBD	3.5%	66%	20%	8%	1.5%	2%	65%	12.0%
2044	4%	4%	30%	TBD	3.5%	68%	20%	8%	1.5%	2%	65%	12.0%
2045	4%	4%	30%	TBD	3.5%	70%	20%	8%	1.5%	2%	65%	12.0%
2046	4%	4%	30%	TBD	3.5%	72%	20%	8%	1.5%	2%	65%	12.0%
2047	4%	4%	30%	TBD	3.5%	74%	20%	8%	1.5%	2%	65%	12.0%
2048	4%	4%	30%	TBD	3.5%	76%	20%	8%	1.5%	2%	65%	12.0%
2049	4%	4%	30%	TBD	3.5%	78%	20%	8%	1.5%	2%	65%	12.0%
2050	4%	4%	30%	TBD	3.5%	80%	20%	8%	1.5%	2%	65%	12.0%

Notes: Except Massachusetts Class I and Rhode Island "New" targets, RPS target assumptions are based on current law. The modeling horizon of AESC 2021 is through 2035; percentage targets are shown through 2050 for reference.
(a) Connecticut Class I supply can be counted toward compliance with Class II requirements
(b) The CES-E target is 20 percent in 2021 and 2022. Beginning in 2023, the CES-E percentage obligation is determined by a formula that is tier to historical production.
(c) The NH PUC has the authority to review and reduce the NH-III RPS target, retroactively, each year.
(d) Vermont Tier I is derived by subtracting the Tier II requirement from the total VT RES goal. Tier II RECs can be counted toward compliance with Tier I requirements.

Alternative compliance payments

Table 57 provides a summary of ACP values for each RPS category. Note that some ACP values stay constant (in nominal terms) throughout the study period, while other values change over time.

Table 57. Summary of Alternative Compliance Payment levels

		2020 Alternative Compliance Payment (nominal $ per MWh)	Notes
CT	Class I	$55.00	$40 beginning 2021. Fixed and flat.
	Class II	$25.00	Fixed and flat.
	Class III	$31.00	Fixed and flat. There is also a $10 floor price.
MA	Class I	$71.57	Adjusted by CPI each year.
	Solar Carve-out I	$384.00	Schedule set by DOER.
	Solar Carve-out II	$316.00	Schedule set by DOER.
	Class II – RE	$29.37	Adjusted by CPI each year.
	Class II – WTE	$11.75	Adjusted by CPI each year.
	APS	$23.50	Adjusted by CPI each year.
	CES	$53.88	75% of Class I ACP in 2020, 50% in 2021 and after
	CES-E	NA	10% of Class I ACP
RI	New	$71.58	Adjusted by CPI each year.
	Existing	$71.58	Adjusted by CPI each year.
ME	Class I	$50.00	Fixed and flat.
	Class II	$50.00	Fixed and flat.
NH	Class I	$57.61	Adjusted by ½ of CPI each year.
	Class I - Thermal	$26.18	Adjusted by ½ of CPI each year.
	Class II	$57.61	Adjusted by ½ of CPI each year.
	Class III	$34.54	Adjusted by CPI each year.
	Class IV	$29.06	Adjusted by CPI each year.
VT	Tier I	$10.71	Adjusted by CPI each year.
	Tier II	$62.74	Adjusted by CPI each year.
	Tier III	$62.74	Adjusted by CPI each year.

Notes: 2021 Alternative Compliance Payments have not yet been released.
The MA RPS regulations are currently under review. AESC 2021 assumes that the proposed Class I ACP of $60 per MWh in 2021, $50 per MWh in 2022, and $40 per MWh in 2023 and thereafter (fixed and flat) will be approved as part of this review. AESC 2021 further assumes that CES ACP and CES-E ACP will continue to be indexed to Class I ACP at the current ratios.
There is no MA CES-E compliance obligation until 2021.
VT Tier II values are estimated based on $60 per MWh in 2018, escalated by CPI thereafter. VT does not appear to publish its ACP rates.

Impacts of the COVID-19 pandemic on Renewable Energy Deployment and Avoided Cost of RPS Compliance

The COVID-19 pandemic has impacted, and will continue to impact, many facets of the renewable energy industry. For large-scale projects in the pipeline, estimates of COVID-induced delays are based on project-specific research and interviews with developers and investors (see Figure 44). For distributed generation projects, the models assume a range of potential delay impacts to near-term projects. The distributed generation delay options are summarized in Table 58, which shows the number of months of delay modeled for projects expected to come on-line each year from 2020 to 2023. Projects with expected commercial operation dates in 2023 or later are not expected to face COVID-induced delays. The *Base Impact* case is used for all counterfactual cases.

Table 58. Range of potential project delays resulting from COVID-19 pandemic

	2020	2021	2022	2023
Low Impact	2 months	1 month	0.5 months	No delay
Base Impact	3 months	1.5 months	0.75 months	No delay
High Impact	5 months	2.5 months	1.25 months	No delay

Figure 44. Potential impacts of the COVID-19 pandemic on renewable energy deployment

Impacts on Project Development Process

- Site access impaired, leading to delays in site control
- Stay-at-home orders, distancing requirements, and resulting limits to on-site activity
- Permitting and construction delays
- Supply chain disruptions
- Most delays translate into increased cost

Impacts on Project Development Pipeline

- Stay-at-home and distancing orders increase costs
- Contracted projects face reduction in available capital
- Little to no appetite for merchant risk
- Schedule delays impair ability to access expiring federal incentives

Impacts on Investment Climate

- Availability of capital depends on developer type and funding source
- Pool of capital expected to contract as a result of general recessive conditions (cash equity) and reduced federal income tax liability (tax equity)
- Lenders (and all investors) challenged to accurately assess risk in this environment
- Offtaker credit risk subject to particular scrutiny
- However, absence of other attractive investments likely to prevent cost of capital from increasing

Impacts on Operating Projects

- Reduced market prices; ISO New England calls for curtailment in export-constrained areas
- Increased O&M costs; exacerbated by supply chain disruptions
- Travel limitations impact O&M crews, resulting in increased unplanned outages
- Limitations on mobility of fuel suppliers (biomass)

7.2. Renewable Energy Certificate (REC) Price Forecasting

This section summarizes REC price forecasting outcomes. Class 1, or "New" markets, are discussed first followed by "Existing" markets. For context, this section also includes a summary of historical REC prices in each market, as represented by broker quotations.

Historical renewable energy certificate prices

We rely upon recent broker quotes, in part, to inform the market prices at which RECs are transacted. REC markets in New England continue to suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since RPS compliance must be substantiated annually, and actual REC transactions occur sporadically throughout the year, the actual weighted average annual price at which RECs are transacted will not necessarily correspond to the straight average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a significant volume of actual transactions. As a result, analysts should filter such data for reasonableness. This table was developed from a representative sampling of REC brokers quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported. For reference, Table 59 shows annual average historical REC prices for new RPS markets. Table 60 shows historical REC prices for existing RPS markets

Table 59. Annual average historical REC prices, New supply: 2015-2020 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020
CT	Class I	$44	$22	$12	$8	$35	$41
MA	Class I	$44	$22	$12	$8	$35	$41
	APS	$21	$21	$20	$17	$9	$7
	CES	NA	NA	NA	NA	NA	NA
RI	New	$43	$23	$12	$7	$34	$41
ME	Class I & IA	$18	$22	$8	$3	$2	$3
NH	Class I	$45	$24	$12	$8	$35	$41
	Class II - Solar	$51	$43	$26	$13	$27	$35
VT	Tier II	NA	NA	NA	NA	NA	NA*
	Tier III	NA	NA	NA	NA	NA	NA*

** Broker quotes not yet available for Vermont markets at the time these data were collected.*

Table 60. Annual average historical REC prices, Existing supply: 2015-2020 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020
CT	Class II	$1	$1	$7	$6	$20	$20
	Class III	$27	$27	$26	$26	$22	$13
MA	Class II – Non-WTE	$27	$26	$26	$26	$23	$20
	Class II – WTE	$6	$6	$6	$6	$10	$11
	CES-E	NA	NA	NA	NA	NA	$2.75
RI	Existing	$1	$1	$1	$1	$1	$1
ME	Class II	$0	$1	$1	$1	$1	$1
NH	Class III	$37	$28	$23	$13	$40	$38
	Class IV	$25	$25	$25	$26	$26	$23
VT	Tier I	NA	NA	NA	NA	NA	NA*

** Broker quotes not yet available for Vermont markets at the time these data were collected.*

Forecasting renewable energy certificate prices for compliance with Class I RPS obligations

The key input to calculating the avoided cost of RPS compliance is REC price. Class I REC prices are forecast using the REMO and Solar Market Study (SMS) models.[178] We describe key methodological steps and assumptions throughout this document. Sustainable Energy Advantage forecasts non-Class I markets with a range of class-specific methodologies, which we describe later in this section.

Near-term supply and demand, REC prices, and renewable energy additions

The Class I REC price forecast from 2021 to approximately 2030 is based on an assessment of the near-term supply and demand balance, ACP levels in each market, banking limits and observed practices, operating import behavior, and discretional curtailment of operating biomass.

Resources considered in the estimation of near-term Class I REC supply and pricing are those eligible for any of the categories listed in Table 55. These resources may fall into one of the following categories:

a) Certified supply, operating and located in ISO New England

b) Certified supply, operating and imported from adjacent control areas

c) Additional potential imports from adjacent control areas, delivered over existing ties; and

d) Near-term committed renewable resources that (i) are in the interconnection queue; (ii) have been RPS-certified in one or more multiple New England states; (iii) secured financing; or (iv) obtained long-term contracts, either with distribution utilities through competitive solicitations, or through other means.

[178] See Section 4.1: *AESC 2021 modeling framework* for more information.

For near-term committed resources that are not yet operational, this analysis applies a customized probability-derating to reflect the likelihood that not all proposed projects will be built or may not be built on the timetable reflected in the queue or as otherwise proposed by the project sponsors.

In addition to the resources described above, we forecast the generation from renewable resources that are expected to come on-line as a result of existing state procurement policies and incentive programs, including but not limited to:

Large-scale renewables

- MA Sec. 83C Offshore Wind Procurement: 1,600 MW by 2026 (Vineyard & Mayflower Wind). *Project selections have been made, and timing updated, since AESC 2018.*
- MA Additional Offshore Wind Procurement, DOER Authority: up to 1,600 MW by 2031. *This procurement policy goal is new since AESC 2018.*
- MA Offshore Wind Procurement, Additional 83C Authority: 2,400 MW (to be procured by 12/31/2027) is expected to be approved during the 2021 legislative session.
- MA Sec. 83D Hydro Procurement: Delivery of 9.45 TWh beginning 7/1/2023 (date on which NECEC is assumed to be energized). *Timing and resource assumptions have been updated since AESC 2018.*
- CT & RI Joint Offshore Wind Procurement: 700 MW (Revolution Wind) by 2025. *Project selections have been made, and timing updated, since AESC 2018.*
- CT Offshore Wind Procurement: 804 MW (Park City Wind) by 2026. *Project selections have been made, and timing updated, since AESC 2018.*
- RI Additional Offshore Wind Procurement: 600 MW in 2021 as announced by Governor Raimondo. *This procurement is new since AESC 2018.*
- ME Long-Term Procurement: Approximately 1 TWh by 2025. *This procurement policy goal is new since AESC 2018.* Tranche 1 was completed in 2020. The RFP for Tranche 2 was released in January 2021.

Distributed generation

- Solar Massachusetts Renewable Target (SMART) Program: 3,200 MW by 2031. *Program expanded from 1,600 to 3,200 MW since AESC 2018.*[179]

[179] To model the hourly generation impacts from distributed solar in the SMART program and all other distributed solar programs, we rely on Horizons Energy's National Database for solar load shapes. Horizons Energy developed the load shapes using irradiation patterns from NREL's PVWatts. They were chosen from airport locations that were closest to the market areas included in the National Database.

- Solar Massachusetts Renewable Target (SMART) Program Expansion: A 2,000 MW expansion (assumed to be reached by 2033) is included in legislation assumed to pass during the 2021 session.
- CT Low and Zero Emissions Renewable Energy Certificate (LREC/ZREC) Programs. *Quantity and timing updated since AESC 2018.*
- CT Low- and Zero-Emissions Tariff Programs. *This program is new since AESC 2018.*
- CT Residential Solar Home REC (RSIP/SHREC) and Tariff Programs. *The Residential Tariff Program is new since AESC 2018.*
- RI Renewable Energy Growth Program (including expansions). *Timing updated since AESC 2018.*[180]
- VT Standard Offer. *Timing updated since AESC 2018.*
- ME Distributed Generation Solar Policy: Large-Scale Shared; Commercial & Institutional. *This program is new since AESC 2018.*
- Net metering and virtual new metering, as applicable, in all New England states. *Quantity and timing updated since AESC 2018.*

Given the eligibility interaction between the MA CES and MA Class I RPS markets, REC and Clean Energy Credit (CEC) price forecasts are modeled interdependently. RECs and ACPs used for Massachusetts Class I compliance will be counted toward CES compliance. Incremental CES demand above the Massachusetts Class I RPS will be satisfied first by non-RPS eligible large hydro resources delivered over new transmission lines (if available), and second—if applicable—by a combination of Class I resources and Massachusetts CES ACPs, depending on regional Class I supply availability.

Forecasted Class I REC supply is allocated proportionally among the states based on an algorithm that accounts for each state's RPS eligibility requirement, banking limits, relative ACP levels, and the expected discretional behavior of operating imports and biomass plants. Each state's resulting supply-demand balance, banking balances, ACPs, and forward-looking market dynamics are used to inform the forecast of near-term Class I REC prices.

Spot prices in the near term will be driven by supply and demand. But they are also influenced by REC market dynamics and to a lesser extent by the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or ACP.
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $2/MWh, reflecting transaction and risk management costs.

[180] Here, and throughout this section, "timing" refers to the estimate of when programmatic capacity will come online.

- Market surplus with banking: Prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

Solar Renewable Energy Certificate (SREC) prices are forecasted using a separate set of proprietary models, developed for Sustainable Energy Advantage's *Massachusetts Solar Market Study*.

Long-term cost of entry and renewable energy additions

The long-term Class I REC price forecast (approximately 2030–2050) is based on the cost of new entry of the marginal renewable energy unit required to meet the incremental RPS demand in each state in each year—and the extrapolation thereof. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential that sorts resources from lowest cost of entry to highest cost of entry. The resources in the supply curve model are represented by 1,277 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year. This supply curve is based on several resource potential studies commissioned by Sustainable Energy Advantage and is proprietary. The cost components of the supply curve analysis are derived from a combination of public (e.g., NREL's ATB) and confidential sources (e.g., Sustainable Energy Advantage research interviews with dozens of New England renewable energy developers).

The supply curve consists of land-based wind, offshore wind, utility-scale solar PV, biomass, biogas, hydro, landfill gas, and tidal resources.[181] While utility-scale solar is the largest potential resource by MW, land-based wind is the largest source by number of blocks (modeled as 1,031 separate individual land-based wind sites). Modeled wind blocks vary by state, land area, number and size of turbines in each project, wind speed, topography, and distance from transmission.

Resources from the supply curve are modeled to meet net demand, which consists of the gross demand for new or incremental renewables, less the near-term renewable supply (as described above).

The estimated 20-year levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure,[182] debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable O&M costs, generator-lead interconnection costs,[183] transmission network upgrade costs,[184] and wind integration costs. Phase-out

[181] The supply curve includes only the Class I eligible resource potential for each resource type.

[182] For this analysis, we assume incremental new supply will be financed with a blend of fully bundled power purchase agreements for a 20-year term and partial hedging for durations available in the short-term for their RECs, energy, and capacity.

[183] As a function of voltage and distance from transmission.

[184] It is assumed that 15-33 percent of the transmission costs are socialized and thereby not borne by the generators.

of the Federal Production Tax Credit and phase-down of the Investment Tax Credit are modeled as adopted in the *Further Consolidated Appropriations Act of 2020*.

Revenues for land-based wind, offshore wind, and utility-scale solar resources are adjusted in two ways:

1. The value of energy is adjusted to reflect these resources' variability, production profile, and, for land-based wind, historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.

2. Land-based wind, offshore wind, and utility-scale solar PV generators are assumed to receive FCM revenues corresponding to only a percentage of nameplate capacity (~25 percent for land-based wind, 45 percent for offshore wind, and 12 percent for utility-scale solar PV), reflecting the seasonal reliability of the intermittent resources, as determined by ISO New England.

The REC cost for each block of the supply curve is estimated for each year. For each generator, we determine the levelized REC premium for market entry, or the additional revenue the project would require in order to attract financing, by performing the following operation: we subtracted (a) the nominal levelized value of production consistent with the AESC 2021 projection of wholesale electric energy and capacity prices from (b) nominal levelized cost of marginal resources.[185] The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis, or:

1. The nominal levelized value of production is the amount the project would receive from selling energy and capacity into the wholesale market; and

2. The difference between the levelized cost and the levelized value represents the REC premium.

Unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from lowest to highest REC premium price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables can never be negative.

Resource levelized cost is expected to undergo several changes throughout the analysis period. These changes include impacts resulting from capital cost decline, technological improvements (increasing capacity factors), and need for transmission solutions, as well as the level of federal tax credits.

The levelized commodity revenue over the life of each resource is based on the sum of energy and capacity prices. REC prices and avoided cost of RPS compliance are derived through an iterative approach. Draft REC prices were based on preliminary energy and capacity forecasts, and were then used to inform final energy and capacity prices. These final prices are inputs for the final REC price and

[185] We calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

avoided RPS compliance cost calculation. See Figure 12 in Section 4.1: *AESC 2021 modeling framework* for more information on this process.

Class 1 or "New" REC price forecasts

Future REC prices in new renewables markets will be driven both by the cost of entry for renewable resources eligible in each state and by the quantity of state-specific supply compared to state-specific demand. RPS eligibility criteria differ by state, and so REC prices are differentiated by state and reflect state-specific expectations with respect to generator certification and LSE-banked compliance. Eligibility criteria also overlap across multiple states, and so the interaction of multi-state supplies and demands and the fungibility of RECs across markets are also considered in this analysis.

For New RPS categories, we assume that in the long run the price of RECs (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies. The supply curve sorts the supply resources from the lowest cost of entry to the highest cost of entry.[186] The resources in the supply curve model are represented by 1,390 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year.

The supply curve consists of land-based wind, offshore wind, utility-scale solar, biomass,[187] hydro, landfill gas, and tidal resources. The price for each block of the supply curve is estimated for each year. For each generator, we determine the 20-year levelized REC premium for market entry, or additional revenue the project would require to enable financing, by subtracting the nominal, levelized energy and capacity prices from the nominal levelized cost of marginal resources:

- The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling its commodities (energy and capacity) into the wholesale market; and
- The difference between the levelized cost and the levelized value represents the REC premium.

As described above, unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from low to high REC premium, and the

[186] These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants, as well as in-house geospatial resource potential studies conducted by Sustainable Energy Advantage, LLC. Typical generator sizes, heat rates, availability and emission rates are consistent with technology assumptions used by ISO New England in its scenario planning process. The resulting supply curve is proprietary to Sustainable Energy Advantage, LLC.

[187] Including biogas and biodiesel.

intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2 per MWh, which is the estimated transaction cost associated with selling renewable resources into the wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure, debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable O&M costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration costs.[188] The analysis assumes the currently planned phase-out of Federal Tax incentives.[189] Capital and operating costs were escalated over time using inflation.

We determined the levelized commodity revenue over the life of each resource based on the sum of energy and capacity prices, both utilizing preliminary AESC 2021 estimates of the FCM price and all-hour zonal LMP.

Resources from the supply curve are modeled to meet net demand, which consists of the gross demand for new or incremental renewables, less existing eligible generation already operating. All imports, as well as New England-based biomass facilities, are modeled as discretional and responsive to expected REC prices through an iterative process. In addition, renewable supply expected to result from long-term procurement and distributed generation policies was modeled independently and netted from gross demand.

The projection of the cost of new entry (REC premium) for Counterfactual #1 is summarized in Table 61. REC premium for market entry (2021 $ per MWh). We assume CEC prices for the Massachusetts CES track MA-1 REC prices until CES-eligible hydro comes online (2023). Thereafter, once hydro contracted under MA Sec. 83D is used to fulfill 100 percent of the CES obligation, we assume a price of $0 because the cost of the 83D contracts cannot be avoided.

Even in years when there is market surplus, REC premiums are not necessarily equal to $0 per MWh. This is because we assume a level of banking injections (to hedge against future shortages) that mitigate potential price crashes that could occur even in years with a large surplus.

[188] We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[189] U.S. Office of Energy Efficiency & Renewable Energy. Last accessed March 10, 2021. "Residential and Commercial ITC Factsheets." *Energy.gov.* Available at https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets.

Table 61. REC premium for market entry (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$39.69	$21.64	$21.64	$2.50	$55.01	$29.82	$44.33
2022	$38.61	$40.18	$40.18	$2.45	$40.18	$24.13	$43.44
2023	$30.14	$31.97	$31.97	$2.40	$31.34	$0.00	$42.60
2024	$20.96	$20.96	$20.96	$2.36	$20.96	$0.00	$35.59
2025	$13.68	$15.04	$15.04	$2.31	$13.90	$0.00	$29.30
2026	$13.56	$14.09	$14.09	$2.27	$13.22	$0.00	$29.59
2027	$12.09	$12.14	$12.14	$2.22	$10.17	$0.00	$34.20
2028	$10.29	$10.40	$10.40	$2.18	$8.44	$0.00	$32.22
2029	$9.89	$10.10	$10.10	$2.13	$8.06	$0.00	$30.26
2030	$22.77	$22.90	$22.90	$2.09	$22.84	$0.00	$28.42
2031	$22.02	$22.27	$22.27	$2.05	$22.14	$0.00	$26.60
2032	$21.62	$21.62	$21.62	$2.01	$21.62	$0.00	$18.85
2033	$7.34	$9.14	$9.14	$1.97	$5.27	$0.00	$17.15
2034	$9.45	$11.14	$11.14	$1.93	$7.65	$0.00	$15.52
2035	$12.67	$13.16	$13.16	$1.90	$12.06	$0.00	$13.95
Levelized (2021-2035)	**$19.38**	**$18.73**	**$18.73**	**$2.19**	**$20.05**	**$3.92**	**$29.99**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$4.50	$50.55	$23.80	$52.37	$61.13	$55.01	$31.21
2022	$4.41	$40.18	$23.55	$46.21	$49.42	$40.18	$31.20
2023	$4.32	$36.65	$23.33	$36.04	$47.46	$31.34	$31.21
2024	$4.24	$20.96	$20.58	$24.10	$20.96	$20.96	$20.96
2025	$4.16	$9.09	$18.17	$15.99	$13.50	$13.90	$13.90
2026	$4.08	$7.86	$16.03	$15.20	$15.70	$13.22	$13.22
2027	$4.00	$7.20	$14.14	$11.70	$18.12	$10.17	$10.17
2028	$3.92	$5.80	$12.49	$9.71	$15.80	$8.44	$8.44
2029	$3.84	$5.29	$11.00	$9.27	$15.13	$8.06	$8.06
2030	$3.77	$22.90	$9.72	$26.26	$22.90	$22.84	$22.84
2031	$3.69	$22.27	$8.57	$25.46	$22.27	$22.14	$22.14
2032	$3.62	$21.62	$7.56	$24.87	$21.62	$21.62	$21.62
2033	$3.55	$3.90	$6.67	$6.06	$11.56	$5.27	$5.27
2034	$3.48	$4.97	$5.89	$8.80	$13.44	$7.65	$7.65
2035	$3.41	$6.07	$5.20	$13.87	$15.06	$12.06	$12.06
Levelized (2021-2035)	**$3.95**	**$18.24**	**$14.15**	**$22.26**	**$24.88**	**$20.05**	**$17.65**

The REC premium (REC Price) results are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. In all cases, project developers will need to be able to secure long-term contracts and attract financing based on the aforementioned natural gas, carbon, and resulting electricity price forecasts in order to create this expected REC market environment. This presents an important caveat to the projected REC prices, as such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are uncertain.

Forecasting renewable energy certificate prices for compliance with existing RPS obligations

As previously described, non-Class I markets are focused on maintaining existing resources—rather than spurring new development—and are therefore fundamentally different from Class I markets. As a result, the approach and assumptions for forecasting non-Class I REC prices must be tailored to a different set of market characteristics. Table 62 describes how REC prices for non-Class I markets are forecasted.

Table 62. REC price forecasting approaches

RPS Market	REC Price Forecast Approach
CT Class II	REC prices are estimated based on current broker quotes and are assumed to trend toward values which reflect a market in equilibrium over time. With limited eligible supply, REC prices are expected to remain modestly below the ACP.
CT Class III	REC prices are estimated based on current broker quotes and are assumed to remain near the minimum nominal Class III REC price of $10/MWh.
ME Class II	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
MA Class II – Non-WTE	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as the lesser of the CT Class I REC price and 75 percent of the MA-II-Non-WTE ACP.
MA Class II – WTE	REC prices are estimated based on current broker quotes. With static supply and stable demand targets, REC prices are expected to remain at or near current levels.
MA APS	REC prices are estimated at 90% of the MA APS ACP.
MA CPS	Based on a proprietary model developed by Sustainable Energy Advantage, including preliminary assumptions before market data were available (circa Nov 2020), and derived as an average of six scenarios.
MA CES	CEC prices are the lesser of the MA Class I price and the CES ACP until CES-eligible hydropower is delivered pursuant to MA 83D contracts. Once these deliveries begin, CEC prices are assumed to decrease to $1/MWh. Once 83D deliveries begin, there will be no CEC "market" because supply will dramatically exceed demand <u>and</u> all eligible supply will be controlled by the distribution utilities. Separately, our understanding is that all CECs in excess of CES demand will be retired by the distribution utilities <u>and</u> their associated over-market costs (defined as the contract cost minus energy and capacity revenues collected upon liquidation into the market) will be collected from all distribution customers.
MA CES-E	REC prices are estimated based on current broker quotes and considering the interaction with other "existing" markets.
NH Class II	REC prices are estimated at the lesser of 105% of the MA Class I REC price and 90% of the NH Class II ACP
NH Class III	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as 90% of the NH-III ACP, assuming a systemic shortage.
NH Class IV	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as the lesser of the CT Class I REC, the MA Class II non-WTE REC price, and 75 percent of the NH Class IV ACP.
RI Existing	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
VT Tier I	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
VT Tier III	Based on the overlap in eligibility, REC prices are estimated based on the lesser of the VT Tier II REC price and the NH Class I Thermal Carve-out Price.

"Existing" REC price forecasts

In contrast to the New RPS markets (where long-term REC prices are based on the cost of new entry), REC prices in Existing RPS markets are based on the relationship between supply and demand, interactions with other markets, and the ACP. Table 63 shows our projection of REC prices for existing resource categories. For reference, Table 60 shows annual average historical REC prices for Existing RPS markets.

Table 63. Summary of REC prices for existing resource categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$20.50	$12.00	$0.75	$23.25	$12.00	$3.50	$36.47	$23.24	$1.00	$0.88
2022	$20.09	$11.76	$0.74	$22.46	$13.23	$3.43	$36.03	$22.22	$0.98	$0.86
2023	$20.74	$11.53	$0.72	$22.46	$12.97	$3.36	$36.20	$22.23	$0.96	$0.84
2024	$22.37	$11.30	$0.71	$20.96	$12.72	$3.30	$36.33	$20.96	$0.94	$0.82
2025	$21.95	$11.09	$0.69	$13.68	$12.47	$3.23	$36.46	$13.68	$0.92	$0.81
2026	$21.52	$10.87	$0.91	$13.56	$12.23	$3.17	$36.56	$13.56	$1.13	$1.02
2027	$21.09	$10.66	$1.11	$12.09	$11.99	$3.11	$36.65	$12.09	$1.33	$1.22
2028	$20.69	$10.45	$1.31	$10.29	$11.76	$3.05	$36.75	$10.29	$1.52	$1.42
2029	$20.26	$10.24	$1.49	$9.89	$11.52	$2.99	$36.80	$9.89	$1.71	$1.60
2030	$19.88	$10.04	$1.67	$22.47	$11.30	$2.93	$36.89	$22.24	$1.88	$1.78
2031	$19.48	$9.84	$1.85	$22.02	$11.07	$2.87	$36.94	$22.02	$2.05	$1.95
2032	$19.10	$9.65	$2.01	$21.62	$10.85	$2.81	$37.03	$21.62	$2.21	$2.11
2033	$18.72	$9.46	$2.17	$7.34	$10.64	$2.76	$37.11	$7.34	$2.36	$2.27
2034	$18.36	$9.28	$2.32	$9.45	$10.44	$2.71	$37.21	$9.45	$2.51	$2.42
2035	$18.00	$9.10	$2.46	$12.67	$10.23	$2.65	$37.31	$12.67	$2.65	$2.56
Levelized (2021-2035)	**$20.24**	**$10.54**	**$1.36**	**$16.45**	**$11.74**	**$3.07**	**$36.70**	**$16.40**	**$1.58**	**$1.47**

Notes: Connecticut Class I supply can be counted toward compliance with Class II requirements. Vermont Tier II supply can be counted toward compliance with Tier I requirements.

7.3. Avoided RPS compliance cost per MWh reduction

The RPS compliance cost that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the percentage of retail load that a supplier must meet from renewable energy under the RPS regulation. In other words:

Equation 1. RPS Compliance Costs

$$\frac{\sum_{n} P_{n,i} \times R_{n,i}}{1-l}$$

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement, expressed as a percentage, for RPS class n in year i,

l = losses from ISO wholesale load accounts to retail meters (modeled at 9 percent)

For example, in a year in which REC prices are $15 per MWh and the RPS percentage target is 10 percent, the avoided RPS cost to a retail customer would be $15 per MWh × 10 percent = $1.50 per MWh.

Comparing results across counterfactuals

Avoided REC prices, and the resulting avoided cost of RPS compliance, are a function of supply and demand dynamics. These dynamics include both policy evolution (i.e., changes to legislation and regulation over time) and market participant behavior (e.g., LSE decisions related to RPS compliance banking, generator decisions related to operations, etc.). The below results differ across counterfactuals based on the relationship between renewable energy buildouts (largely driven by policy), load (driven by both behavior and energy efficiency and electrification assumptions), and REC price. As such, the avoided cost of RPS compliance may vary between counterfactuals as a result of differences in modeled load even when renewable energy buildouts are the same.

Counterfactual #1 results

Table 64 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 65 and Table 66 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 64. Avoided cost of RPS compliance for Counterfactual #1 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**

Table 65. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.73	$2.36	$1.18	$0.01	$7.57	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.54	$3.48	$3.83	$0.03	$5.81	$0.00	$2.79
2024	$6.40	$2.28	$3.43	$0.04	$4.73	$0.00	$2.91
2025	$4.47	$1.64	$3.12	$0.05	$3.65	$0.00	$3.03
2026	$4.73	$1.54	$3.53	$0.06	$4.01	$0.00	$3.79
2027	$4.48	$1.32	$3.57	$0.07	$3.55	$0.00	$5.13
2028	$4.04	$1.13	$3.51	$0.08	$3.31	$0.00	$5.36
2029	$4.09	$1.10	$3.85	$0.08	$3.43	$0.00	$5.52
2030	$9.93	$2.50	$9.98	$0.09	$9.96	$0.00	$5.65
2031	$9.60	$2.43	$9.71	$0.09	$9.89	$0.00	$5.73
2032	$9.43	$2.36	$9.43	$0.09	$9.90	$0.00	$4.37
2033	$3.20	$1.00	$3.98	$0.09	$2.47	$0.00	$4.25
2034	$4.12	$1.21	$4.86	$0.08	$3.67	$0.00	$4.10
2035	$5.52	$1.43	$5.74	$0.08	$5.92	$0.00	$3.91
Levelized (2021-2035)	**$6.59**	**$2.03**	**$4.83**	**$0.06**	**$5.61**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$6.28	$2.49	$0.40	$10.33	$2.04	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.27	$2.80	$0.28	$17.50	$1.57	$2.04
2024	$0.28	$3.22	$2.67	$0.18	$9.82	$1.19	$1.52
2025	$0.28	$1.49	$2.53	$0.12	$7.68	$0.88	$1.11
2026	$0.29	$1.29	$2.24	$0.12	$10.50	$0.92	$1.15
2027	$0.29	$1.18	$1.97	$0.09	$13.93	$0.78	$0.96
2028	$0.30	$0.95	$1.74	$0.07	$13.72	$0.70	$0.86
2029	$0.30	$0.86	$1.54	$0.07	$14.65	$0.72	$0.88
2030	$0.31	$3.74	$1.36	$0.20	$24.46	$2.19	$2.66
2031	$0.31	$3.64	$1.20	$0.19	$23.79	$2.27	$2.73
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.36	$2.83
2033	$0.32	$0.64	$0.93	$0.05	$12.35	$0.57	$0.69
2034	$0.32	$0.81	$0.82	$0.07	$14.35	$0.83	$1.00
2035	$0.33	$0.99	$0.73	$0.11	$16.09	$1.31	$1.58
Levelized (2021-2035)	**$0.30**	**$2.66**	**$1.80**	**$0.17**	**$14.96**	**$1.34**	**$1.56**

Table 66. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.82	$0.49	$0.72	$3.17	$0.34	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.54	$0.48	$0.71	$3.18	$0.22	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.47	$0.46	$0.68	$3.20	$0.20	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.40	$0.45	$0.66	$3.20	$0.17	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.39	$0.44	$0.65	$3.21	$0.16	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.86	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.85	$0.41	$0.61	$3.23	$0.35	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.29	$0.41	$0.60	$3.24	$0.12	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.37	$0.40	$0.59	$3.25	$0.15	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.50	$0.39	$0.58	$3.25	$0.21	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.64**	**$0.45**	**$0.67**	**$3.20**	**$0.27**	**$0.03**	**$1.00**

Counterfactual #2 results

Table 67 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 68 and Table 69 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 67. Avoided cost of RPS compliance for Counterfactual #2 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.43	$3.10	$3.10	$1.31	$5.62	$0.75
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**

Table 68. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$8.95	$0.96	$0.48	$0.01	$5.02	$1.29	$1.45
2022	$5.90	$2.46	$1.97	$0.02	$3.58	$0.98	$2.13
2023	$6.60	$2.54	$2.79	$0.03	$4.32	$0.00	$2.79
2024	$3.94	$1.36	$2.04	$0.04	$3.13	$0.00	$2.91
2025	$3.98	$1.32	$2.51	$0.05	$3.30	$0.00	$3.03
2026	$0.63	$1.09	$2.50	$0.06	$3.04	$0.00	$3.79
2027	$2.92	$0.87	$2.35	$0.07	$2.99	$0.00	$5.13
2028	$2.39	$0.75	$2.33	$0.08	$2.46	$0.00	$5.36
2029	$2.20	$0.63	$2.21	$0.08	$2.29	$0.00	$5.52
2030	$1.92	$0.47	$1.89	$0.09	$2.07	$0.00	$5.65
2031	$1.75	$0.38	$1.53	$0.09	$2.03	$0.00	$5.73
2032	$1.88	$0.37	$1.49	$0.09	$2.30	$0.00	$4.37
2033	$2.23	$0.44	$1.75	$0.09	$2.86	$0.00	$4.25
2034	$2.69	$0.55	$2.19	$0.08	$3.57	$0.00	$4.10
2035	$2.66	$0.61	$2.44	$0.08	$3.37	$0.00	$3.91
Levelized (2021-2035)	**$3.43**	**$1.00**	**$2.03**	**$0.06**	**$3.10**	**$0.16**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$4.54	$2.49	$0.32	$6.17	$1.35	$1.59
2022	$0.26	$3.02	$2.64	$0.20	$6.06	$0.98	$1.31
2023	$0.27	$3.35	$2.80	$0.20	$8.59	$1.17	$1.52
2024	$0.28	$1.12	$2.67	$0.12	$6.13	$0.79	$1.01
2025	$0.28	$1.02	$2.53	$0.11	$7.57	$0.80	$1.01
2026	$0.29	$0.81	$2.24	$0.09	$7.61	$0.70	$0.87
2027	$0.29	$0.61	$1.97	$0.08	$5.58	$0.65	$0.81
2028	$0.30	$0.57	$1.74	$0.06	$4.79	$0.52	$0.64
2029	$0.30	$0.57	$1.54	$0.05	$4.90	$0.48	$0.59
2030	$0.31	$0.54	$1.36	$0.04	$4.21	$0.46	$0.55
2031	$0.31	$0.51	$1.20	$0.04	$3.72	$0.47	$0.56
2032	$0.32	$0.49	$1.05	$0.04	$4.01	$0.55	$0.66
2033	$0.32	$0.55	$0.93	$0.05	$4.43	$0.66	$0.80
2034	$0.32	$0.65	$0.82	$0.07	$4.86	$0.81	$0.97
2035	$0.33	$0.75	$0.73	$0.06	$5.25	$0.75	$0.90
Levelized (2021-2035)	**$0.30**	**$1.31**	**$1.80**	**$0.10**	**$5.62**	**$0.75**	**$0.93**

Table 69. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.13	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$1.97	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$2.03	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.51	$0.49	$0.72	$3.17	$0.21	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.48	$0.48	$0.71	$3.18	$0.20	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.07	$0.47	$0.69	$3.19	$0.03	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.31	$0.46	$0.68	$3.20	$0.13	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.24	$0.45	$0.66	$3.20	$0.10	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.21	$0.44	$0.65	$3.21	$0.09	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.17	$0.43	$0.64	$3.22	$0.07	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.16	$0.42	$0.63	$3.22	$0.07	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.17	$0.41	$0.61	$3.23	$0.07	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.20	$0.41	$0.60	$3.24	$0.08	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.24	$0.40	$0.59	$3.25	$0.10	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.24	$0.39	$0.58	$3.25	$0.10	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.39**	**$0.45**	**$0.67**	**$3.04**	**$0.16**	**$0.03**	**$1.00**

Counterfactual #3 results

Table 70 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 71 and Table 72 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 70. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

Table 71. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.46	$2.36	$1.18	$0.01	$6.81	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.56	$3.55	$3.90	$0.03	$5.82	$0.00	$2.79
2024	$7.04	$2.52	$3.77	$0.04	$5.21	$0.00	$2.91
2025	$4.55	$1.68	$3.20	$0.05	$3.67	$0.00	$3.03
2026	$4.67	$1.50	$3.45	$0.06	$4.03	$0.00	$3.79
2027	$4.26	$1.37	$3.70	$0.07	$2.94	$0.00	$5.13
2028	$3.83	$1.25	$3.87	$0.08	$2.70	$0.00	$5.36
2029	$3.86	$1.21	$4.24	$0.08	$2.63	$0.00	$5.52
2030	$9.80	$2.50	$9.98	$0.09	$9.88	$0.00	$5.65
2031	$9.63	$2.43	$9.71	$0.09	$9.91	$0.00	$5.73
2032	$8.85	$2.36	$9.43	$0.09	$9.72	$0.00	$4.37
2033	$7.56	$1.89	$7.56	$0.09	$8.13	$0.00	$4.25
2034	$9.18	$2.30	$9.18	$0.08	$10.10	$0.00	$4.10
2035	$11.33	$2.81	$11.25	$0.08	$12.94	$0.00	$3.91
Levelized (2021-2035)	**$7.50**	**$2.28**	**$5.77**	**$0.06**	**$6.66**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$5.61	$2.49	$0.40	$9.31	$1.84	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.37	$2.80	$0.28	$17.53	$1.57	$2.04
2024	$0.28	$3.55	$2.67	$0.20	$10.82	$1.31	$1.68
2025	$0.28	$1.51	$2.53	$0.12	$8.00	$0.88	$1.12
2026	$0.29	$1.32	$2.24	$0.12	$9.98	$0.93	$1.16
2027	$0.29	$1.27	$1.97	$0.07	$14.83	$0.64	$0.79
2028	$0.30	$1.06	$1.74	$0.06	$14.03	$0.57	$0.70
2029	$0.30	$0.97	$1.54	$0.05	$15.66	$0.55	$0.67
2030	$0.31	$3.74	$1.36	$0.20	$24.45	$2.17	$2.64
2031	$0.31	$3.64	$1.20	$0.19	$23.78	$2.27	$2.74
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.31	$2.78
2033	$0.32	$2.83	$0.93	$0.15	$18.52	$1.89	$2.27
2034	$0.32	$3.44	$0.82	$0.18	$22.50	$2.30	$2.76
2035	$0.33	$4.21	$0.73	$0.23	$28.36	$2.88	$3.45
Levelized (2021-2035)	**$0.30**	**$3.18**	**$1.80**	**$0.19**	**$16.77**	**$1.58**	**$1.86**

Table 72. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.88	$0.49	$0.72	$3.17	$0.36	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.55	$0.48	$0.71	$3.18	$0.23	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.45	$0.46	$0.68	$3.20	$0.19	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.38	$0.45	$0.66	$3.20	$0.16	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.37	$0.44	$0.65	$3.21	$0.15	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.87	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.80	$0.41	$0.61	$3.23	$0.33	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.68	$0.41	$0.60	$3.24	$0.28	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.83	$0.40	$0.59	$3.25	$0.34	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.88	$0.39	$0.58	$3.25	$0.36	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.72**	**$0.45**	**$0.67**	**$3.20**	**$0.30**	**$0.03**	**$1.00**

Counterfactual #4 results

Table 73 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 74 and Table 75 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 73. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

Table 74. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.46	$2.36	$1.18	$0.01	$6.81	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.56	$3.55	$3.90	$0.03	$5.82	$0.00	$2.79
2024	$7.04	$2.52	$3.77	$0.04	$5.21	$0.00	$2.91
2025	$4.55	$1.68	$3.20	$0.05	$3.67	$0.00	$3.03
2026	$4.67	$1.50	$3.45	$0.06	$4.03	$0.00	$3.79
2027	$4.26	$1.37	$3.70	$0.07	$2.94	$0.00	$5.13
2028	$3.83	$1.25	$3.87	$0.08	$2.70	$0.00	$5.36
2029	$3.86	$1.21	$4.24	$0.08	$2.63	$0.00	$5.52
2030	$9.80	$2.50	$9.98	$0.09	$9.88	$0.00	$5.65
2031	$9.63	$2.43	$9.71	$0.09	$9.91	$0.00	$5.73
2032	$8.85	$2.36	$9.43	$0.09	$9.72	$0.00	$4.37
2033	$7.56	$1.89	$7.56	$0.09	$8.13	$0.00	$4.25
2034	$9.18	$2.30	$9.18	$0.08	$10.10	$0.00	$4.10
2035	$11.33	$2.81	$11.25	$0.08	$12.94	$0.00	$3.91
Levelized (2021-2035)	**$7.50**	**$2.28**	**$5.77**	**$0.06**	**$6.66**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$5.61	$2.49	$0.40	$9.31	$1.84	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.37	$2.80	$0.28	$17.53	$1.57	$2.04
2024	$0.28	$3.55	$2.67	$0.20	$10.82	$1.31	$1.68
2025	$0.28	$1.51	$2.53	$0.12	$8.00	$0.88	$1.12
2026	$0.29	$1.32	$2.24	$0.12	$9.98	$0.93	$1.16
2027	$0.29	$1.27	$1.97	$0.07	$14.83	$0.64	$0.79
2028	$0.30	$1.06	$1.74	$0.06	$14.03	$0.57	$0.70
2029	$0.30	$0.97	$1.54	$0.05	$15.66	$0.55	$0.67
2030	$0.31	$3.74	$1.36	$0.20	$24.45	$2.17	$2.64
2031	$0.31	$3.64	$1.20	$0.19	$23.78	$2.27	$2.74
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.31	$2.78
2033	$0.32	$2.83	$0.93	$0.15	$18.52	$1.89	$2.27
2034	$0.32	$3.44	$0.82	$0.18	$22.50	$2.30	$2.76
2035	$0.33	$4.21	$0.73	$0.23	$28.36	$2.88	$3.45
Levelized (2021-2035)	**$0.30**	**$3.18**	**$1.80**	**$0.19**	**$16.77**	**$1.58**	**$1.86**

Table 75. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.88	$0.49	$0.72	$3.17	$0.36	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.55	$0.48	$0.71	$3.18	$0.23	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.45	$0.46	$0.68	$3.20	$0.19	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.38	$0.45	$0.66	$3.20	$0.16	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.37	$0.44	$0.65	$3.21	$0.15	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.87	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.80	$0.41	$0.61	$3.23	$0.33	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.68	$0.41	$0.60	$3.24	$0.28	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.83	$0.40	$0.59	$3.25	$0.34	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.88	$0.39	$0.58	$3.25	$0.36	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.72**	**$0.45**	**$0.67**	**$3.20**	**$0.30**	**$0.03**	**$1.00**

8. NON-EMBEDDED ENVIRONMENTAL COSTS

Some environmental costs are embedded (economists would say "internalized") in energy prices through regulations that require expenditures to reduce emissions. Other environmental impacts, which also impose real damages on society, are not embedded in prices. Non-embedded costs are (by definition) not included in the AESC 2021 modeling of avoided energy costs. In contrast, costs associated with RGGI, SO_2 regulation programs, and Massachusetts' 310 CMR 7.74 regulation are included in the AESC 2021 modeling of energy prices and thus impact the avoided energy costs in a quantifiable way (see Section 4.8: *Embedded emissions regulations* for a discussion of how these costs are modeled).

For the AESC 2021 Study, we estimate values for some of the principal non-embedded environmental costs. Here we address two such categories: the non-embedded portion of GHG impacts, and the costs of NO_X emissions.

Because different states participating in the AESC study have differing policy contexts, we offer several different options and approaches for calculating the non-embedded GHG cost. AESC 2021 provides these approaches to enable individual states to address specific policy directives regarding GHG impacts. Table 76 and Table 77 compares these four values to values described in AESC 2018.

- A "damage cost" approximated by the social cost of carbon (SCC). There are many different options for a social cost of carbon. The Synapse Team recommends using a value that applies low discount rates, considers global damages, and considers the impact of high-risk situations. One source for this value is the December 2020 SCC Guidance published by the State of New York. Using a 2 percent discount rate (the one also recommended by New York for most decision-making), we recommend a 15-year levelized SCC of $128 per short ton in AESC 2021. We also recommend that program administrators continually review this value (e.g., for the purposes of mid-term modifications), as updates to the federally-recommended SCC are expected in early 2022.

- An approach based on global marginal abatement costs. In AESC 2021, we estimate a total environmental cost based on the cost of large-scale CCS equal to $92 per short ton of CO_2-eq. This is lower than the $105 per short ton of CO_2-eq value (in 2021 dollars) described in AESC 2018. This lower cost reflects the declining costs of this technology.

- An approach based on New England marginal abatement costs, assuming a cost derived from electric sector technologies. In AESC 2021, this is a total environmental cost of $125 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard. This compares to a cost of $72 per short ton of CO_2-eq emissions (in 2021 dollars) based on a projection of future costs of offshore wind energy, as described in AESC 2018. This increased cost reflects updated information on this technology in the United States, as well as lower energy costs in this edition of AESC.

- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors. In AESC 2021, this is a total environmental cost of $493 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for RNG derived from power-to-gas technology. This approach may be useful for policymakers who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050).

Table 76. Comparison of GHG costs under different approaches (2021 $ per short ton) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	$128	-	-
Global marginal abatement cost	$105	$92	-$13	-12%
New England-based marginal abatement cost, derived from the electric sector	$72	$125	$53	75%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	$493	-	-

Notes: All values shown are levelized over 15 years. All AESC 2021 values except the SCC are levelized using a 0.81 percent discount rate (SCC uses a 2.0 percent discount rate). All AESC 2018 values are levelized using a 1.34 percent discount rate, then converted into 2021 dollars. In AESC 2018, damage costs were discussed, but not quantified. AESC 2018 did not discuss or estimate a New England-based marginal abatement cost derived from multiple sectors. Values shown above remove energy prices, but not embedded costs. Values shown above do not include losses.

Table 77. Comparison of GHG costs under different approaches (2021 cents per kWh) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	4.87	-	-
Global marginal abatement cost	4.64	3.41	-1.23	-26%
New England-based marginal abatement cost, derived from the electric sector	2.83	4.74	1.91	67%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	19.72	-	-

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75. All values are quoted using a summer on-peak seasonal marginal emission rate, and include a 9 percent energy loss factor.

AESC users may wish to include a non-embedded cost to fully account for the cost of GHG impacts or GHG abatement. In order to do this, users must first subtract out the RGGI cost (in Connecticut, Maine, New Hampshire, Rhode Island, or Vermont) or both the RGGI cost and 310 CMR 7.74 cost (in Massachusetts only) from the relevant GHG emission cost to determine the remaining cost that is non-embedded. The non-embedded NO_X cost may be simply added to the energy cost, as we do not model an embedded NO_X cost in AESC 2021. We find a non-embedded NO_X emission cost of $14,700 per short ton of NO_X, based on a review of findings in the literature.

See Appendix B: *Detailed Electric Outputs* and Appendix G: *Marginal Emission Rates and Non-embedded Environmental Cost Detail* for more detail on this topic.

8.1. Non-embedded GHG costs

Costs of GHG emissions are partially embedded in prices through RGGI allowances, state regulations such as 310 CMR 7.74 and 310 CMR 7.75 in Massachusetts, and federal policies such as the previously proposed Clean Power Plan. However, the costs embedded by these policies represent only a portion of the total environmental impacts of GHG emissions. Therefore, we estimate the total cost of GHG emissions; the non-embedded portion is the difference between our total cost estimates and the smaller, embedded portion of GHG impacts. Because different states participating in the AESC study have differing policy contexts, we offer several different options and approaches for calculating the non-embedded GHG cost. Because of the time horizon of modeling in AESC 2021, our costs are focused on the likely costs expected in the timeframe of 2021 through 2035.

There are two leading methods for estimating environmental costs: based on damage costs or based on marginal abatement costs. (In the idealized market of textbook economics, the two would coincide; in the real world, they are not necessarily identical.)

Social cost of carbon (damage cost)

The SCC attempts to monetize the current and future damages resulting from CO_2 emissions.[190] Policymakers can use this value to assess policies that address climate change. Developing a reasonable value for the SCC can be a complex endeavor. This section describes the SCC promulgated and used by the U.S. federal government, as well as SCC studies and guidelines by other parties. This section closes with an SCC recommendation for users of AESC.

Federal agency consideration of the SCC

In a series of analyses beginning in 2009, the Obama Administration convened an Interagency Working Group (IWG) to develop a recommendation for an SCC value to use in decision-making by federal agencies. The revised technical support document published in August 2016 relies on outputs from three different integrated assessment models (IAM) to develop sets of SCC values.[191] These different sets of values vary according to the discount rate used (i.e., how heavily future damages are discounted) and whether or not they include lower-probability, higher-impact values. The Obama Administration issued a central recommendation of a 3 percent discount rate, without the inclusion of higher-impact values. This yields an SCC value of $49 per short ton of CO_2 in 2021, (in 2021 dollars). These values escalate over time; by 2050, these values are 1.7 times larger than the 2020 values, in real-dollar terms.

[190] In most contexts, the SCC is recommended to also be applied to other GHGs (e.g., methane, nitrous oxides). In these situations, the SCC is converted using a series of calculations that seek to estimate the equivalent impacts of disparate GHGs. For purposes of simplification, this text makes reference to "SCC" only, although this value should appropriately be converted and applied to other GHG emissions as necessary.

[191] Interagency Working Group on Social Cost of Greenhouse Gases. August 2016. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866.* Available at https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf.

In 2017, the Trump Administration issued guidance to update the SCC estimate that only included domestic impacts of carbon emissions and to recommend discount rates from 3 to 7 percent. At the lower bound of 3 percent, the Trump Administration estimated the SCC to be $7 per short ton of carbon dioxide in 2020 (in 2021 dollars). This value is just one-seventh of the Obama Administration's estimate. At a discount rate of 7 percent, the Trump Administration found an SCC of $1 per short ton of carbon dioxide in 2020 (in 2021 dollars).[192] The issue with measuring only domestic damages of carbon, however, is that the emissions quickly spread on a global scale and contribute to climate change impacts around the world. Moreover, high discount rates such as 7 percent are a way to reflect returns on capital, rather than climate change impacts for future generations.[193]

In February 2021, the Biden Administration issued its draft guidance for the SCC.[194] The draft guidance rescinds the 2019 draft GHG guidance issued by the Trump Administration, effectively rejecting the 7 percent discount rate and the notion that climate change damages caused by U.S. emissions but suffered in other countries should be ignored. The Biden Administration has stated that it intends to re-convene the IWG, re-estimate the SCC, and re-issue new guidance on a federal SCC in January 2022. We should anticipate that the update will reflect recent information and analysis of climate impacts, valuation of damages, and discounting. The February 2021 guidance states that, "[I]n the interim, agencies should consider all available tools and resources in assessing GHG emissions and climate change effects of their proposed actions, including, as appropriate and relevant, the 2016 GHG Guidance."[195]

Other SCC recommendations

The federal IWG SCC is one among many SCC calculations. Some other calculations of the SCC use one of the identical models used by the IWG, but update key parameters.[196] Yet other calculations of the SCC utilize different models and also take low-probability but higher-impact costs into account (see, for

[192] U.S. Government Accountability Office. June 2020. *Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis.* Available at https://www.gao.gov/assets/gao-20-254.pdf. See Page 57, Table 10.

[193] U.S. Government Accountability Office. June 2020. *Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis.* Available at https://www.gao.gov/assets/gao-20-254.pdf. See Page 32.

[194] Council on Environmental Quality. February 19, 2021. "National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions." *Federalregister.gov.* Available at https://www.federalregister.gov/documents/2021/02/19/2021-03355/national-environmental-policy-act-guidance-on-consideration-of-greenhouse-gas-emissions.

[195] Executive Office of the President. January 20, 2021. "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." *Federalregister.gov.* Available at https://www.federalregister.gov/documents/2021/01/25/2021-01765/protecting-public-health-and-the-environment-and-restoring-science-to-tackle-the-climate-crisis.

[196] Nordhaus, W.D. 2017. "Revisiting the social cost of carbon." *Proceedings of the National Academy of Sciences,* 114 (7) 1518-1523; DOI: 10.1073/pnas.1609244114. https://doi.org/10.1073/pnas.1609244114 and Hansel, C. M. et al. 2020. "Climate economics support for the UN climate targets." *Nature Climate Change*. http://acdc2007.free.fr/hansel720.pdf.

example the 2014 meta-analysis described in AESC 2018).[197] These studies may also recommend the use of lower discount rates than those analyzed by the IWG.[198] While high discount rates may be useful in contexts relating to financial rates of return, lower discount rates are thought to be more ethically compatible with preserving the planet for future generations of humanity, and thus more appropriate for an SCC. Still other calculations may be derived through other means, including meta-analysis of other research.[199] Depending on the year being described and discount rate used, SCCs in these studies range from roughly $53 to $820 per short ton of CO_2 (in 2021 dollars). We note there are also published recommendations on the SCC that do not necessarily specify values, but instead suggest best practices for performing the calculation.[200]

Generally speaking, experts examining or calculating an SCC typically recommend using reasonable, low discount rates; evaluating the SCC with a global perspective; and including the evaluation of low-probability, high-impact events in either the "main" SCC being recommended or in separate sensitivities.

New York State Social Cost of Carbon Guideline

In December 2020, the New York State Department of Environmental Conservation released a guideline document titled "Establishing a Value of Carbon" (the NYS SCC Guideline).[201] This document provides a range of carbon values as well as guidance for state entities on which values to use. Most notably, the NYS SCC Guideline recommends using the values identified as an interim SCC by the Biden Administration in February 2021 (and previously issued by the Obama Administration in 2016), but with a different range of discount rates. We discuss this guidance document in detail due to New York's similar energy landscape and policy context to the six New England states.

The NYS SCC Guideline recommends basing the SCC on the estimations calculated by the federal IWG in 2016 and identified as interim in 2021, as these use a global scope of emissions impacts and estimate impacts through the year 2300. As described above, the federal IWG uses an average SCC from three different IAMs models to provide robustness to the final calculation. The NYS SCC Guideline also recommends that the full scope of impacts of all relevant GHGs (e.g., methane, nitrous oxide) should be considered, not just CO_2. This is necessary to ensure that reducing one type of emissions does not transfer the pollution to another emission or jurisdiction. Similarly, the NYS SCC Guideline explains the

[197] J.X.J.M. van den Bergh and W.J.W. Botzen (2014), "A lower bound to the social cost of CO_2 emissions," *Nature Climate Change* 4, 253-258

[198] Stern, N., and J. E. Stiglitz. 2021. "The Social Cost of Carbon, Risk, Distribution, Market Failures: An Alternative Approach." NBER Working Paper Series. http://www.nber.org/papers/w28472

[199] Richard S J Tol, 2018. "The Economic Impacts of Climate Change." *Review of Environmental Economics and Policy*, Volume 12, Issue 1, Pages 4–25, https://doi.org/10.1093/reep/rex027. Also available at https://academic.oup.com/reep/article/12/1/4/4804315#110883856.

[200] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651.

[201] New York State Department of Environmental Conservation. 2020. *Establishing a Value of Carbon: Guidelines for Use by State Agencies.* Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf

necessity of considering the global impact of emissions, as carbon impacts are not localized. Furthermore, the NYS SCC Guideline recommends staying up-to-date with peer-reviewed literature related to the SCC to ensure the most accurate cost estimates. Finally, the NYS SCC Guideline encourages the use of an appropriate discount rate, different from the range in the IWG document.

While the federal IWG provides SCC values using discount rates of 2.5 percent, 3 percent, and 5 percent (with a "central" identified value of 3 percent) the NYS SCC Guideline recommends calculating the SCC at a discount rate of 1 percent, 2 percent, and 3 percent to understand the range of potential SCC values.[202] In particular, the NYS SCC Guideline also recommends using a central discount rate of no more than 2 percent for decision-making. The NYS SCC Guideline recommends relying on the central discount rate of 2 percent or less for several reasons:

- First, higher discount rates are more appropriate for evaluating private investments, while the issues here are about long-term impacts to the public from global climate change.
- Second, the NYS SCC Guideline points out that recent research has found that the federal IWG underestimates the value of avoiding emissions damages (see discussion above on other estimates of the SCC that utilize the same methodology as the IWG, but update key input parameters). The NYS SCC Guideline notes that the federal IWG estimates do not fully account for damages from high-impact events or climatic tipping points, and that these damages could be accounted for through the use of lower discount rates.
- Third, the NYS SCC Guideline does not recommend using a discount rate of 0 percent at this time. A discount rate of 0 percent values the present and future equally, which is potentially not representative of how society values the present and future.
- Fourth, the NYS SCC Guideline notes that, "Experts now generally consider a range of 1–3 percent to be more acceptable." A 2 percent discount rate is the central value of this range.

As a result, the NYS SCC Guideline recommends a discount rate of no more than 2 percent, as this will best account for public safety and welfare and significant environmental impacts, while recognizing some difference in societal value between the present and the long-term future. The NYS SCC Guideline notes that "[a]dditional approaches such as declining discount rates and providing estimates at the 95th percentile of the central value could also be considered by the Department in the future as more review and refinement of the estimates occur." Accordingly, the NYS SCC Guideline recommends an SCC of

[202] It is theoretically possible to calculate an SCC using any discount rate, rather than the ones enumerated here. However, the application of discount rates in the SCC calculation happens fairly early in the methodology, meaning that users of the SCC are limited to the use of the SCCs calculated using the published discount rates.

\$116 per short ton of CO_2 at a 2 percent discount rate (in 2021 dollars), escalating over time.[203] On a 15-year levelized basis, this SCC is equal to \$128 per short ton of CO_2.

Recommendation for AESC 2021

Table 78 summarizes the NYS SCC Guideline values across time and provides a levelized 15-year value for each of the three series. We recommend that users of AESC rely on the SCC values shown in the column based on the 2 percent discount rate, with SCC values ranging from \$116 (in 2020) to \$165 (in 2050) in 2021 dollars per short ton of CO_2, and a 15-year levelized value of \$128 per short ton. We recommend the use of a central value of 2 percent for the discount rate in line with the NYS SCC Guideline. This SCC value is likely to be suitable for use in New England states that consider the social cost of GHGs in cost-effectiveness planning, since the New England states are similar to New York in terms of energy landscape and policy context. Moreover, the NYS SCC Guideline values consider the global impact of emissions, use reasonable discount rates, and consider high-impact events through low discount rates. Analyses since the August 2016 IWG report support expectations of greater damages from climate change and the use of lower discount rates. For example, a survey of approximately 200 experts found a mean recommended social discount rate (SDR) of 2 percent, and that "[m]ore than 90 percent are comfortable with a SDR somewhere in the interval of 1 percent to 3 percent."[204]

Note that the discount rate we recommend for the SCC is different than the discount rate used elsewhere in AESC. For the SCC, we recommend the use of a 2 percent discount rate, as this discount rate is based in part on an ethical consideration of the value of future generations of humanity, rather than derived from observations in the financial markets (such as treasury bill rates or utility rates of return, which are largely unrelated to considerations important to the SCC).[205] Other values described in Table 78 may be useful to examine in sensitivity testing of program or measure cost-effectiveness.

[203] New York State Department of Environmental Conservation. 2020. *Appendix: Value of Carbon.* Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. Values were originally reported in 2020 dollars per metric ton; here, they have been converted into 2021 dollars per short ton using AESC 2021's deflator.

[204] Drupp, M.A., M.C. Freeman, B. Groom, F. Nesje. 2018. "Discounting Disentangled." *American Economic Journal: Economic Policy*, November, page 33.

[205] We note that the original 2003 methodology used to calculate a 3 percent discount rate involved subtracting the 30-year average of year-on-year CPI changes (1973 through 2002) from the 30-year average of 10-year U.S. Treasury yields (1973 through 2002). Using the data currently available from the U.S. Treasury and the Bureau of Labor Statistics, we calculate an implied discount rate of 3.01 percent, which rounds to 3 percent. When this same methodology is applied to a more recent 30-year period spanning 1991 through 2020, we calculate an implied discount rate of 2.02 percent, which rounds to 2 percent. In short, even if one were to rely exclusively on financial markets to determine an appropriate discount rate for the social cost of carbon, it would be appropriate to use a 2 percent discount rate rather than a 3 percent discount rate.

Obama White House Archives. Last accessed March 11, 2021. "Circular A-4." Obamawhitehouse.org. Available at https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

U.S. Department of Treasury. Last accessed March, 11. 2021. "Daily Treasury Yield Curve Rates." *Treasury.gov.* Available at https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield.

U.S. Bureau of Land Statistics. Last accessed March 11, 2021. "Historical Consumer Price Index for All Urban Consumers." *Bls.gov.* Available at https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202101.pdf.

Importantly, we note that this is the recommendation being made by the AESC authors at the time of this report's writing. It is possible—even likely—that this value will change as new information becomes available. Such new information may include new data on high-impact events and climate change risks and feedbacks, information about time preference and discount rates, updated model input parameters, or other factors. This information may be promulgated by the federal government in the course of the Biden Administration's final SCC rulemaking, due to be released in January 2022, or from independent assessments published by various third parties. We recommend that program administrators continually review this value and potentially revisit an update to this value for mid-term modification purposes in early 2022.

Whenever possible, we also recommend considering the full scope of emissions impacts and the effect on non-carbon emissions to ensure one pollutant is not replaced by another.

Table 78. Comparison of social costs of carbon at varying discount rates from NYS SCC Guideline and federal IWG (2021 dollars per short ton)

	3.0%	2.0%	1.0%
2020	$49	$116	$390
2021	$49	$118	$391
2022	$51	$119	$394
2023	$52	$120	$396
2024	$53	$122	$399
2025	$55	$124	$401
2026	$56	$125	$403
2027	$56	$127	$405
2028	$57	$129	$408
2029	$57	$130	$410
2030	$59	$131	$413
2031	$60	$133	$415
2032	$61	$135	$416
2033	$62	$136	$419
2034	$64	$138	$421
2035	$65	$140	$424
2036	$66	$142	$426
2037	$68	$143	$428
2038	$68	$144	$430
2039	$69	$146	$432
2040	$70	$148	$434
2041	$72	$150	$437
2042	$72	$152	$440
2043	$73	$154	$442
2044	$74	$155	$445
2045	$75	$157	$447
2046	$77	$158	$449
2047	$78	$160	$451
2048	$79	$162	$452
2049	$81	$163	$454
2050	$81	$165	$456
15-year levelized	**$57**	**$128**	**$407**

Sources and notes: Values are obtained from https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. All values have been converted into 2021 dollars per short tons. Value streams are shown from lowest to highest, left to right. All levelization calculations were performed using each column's noted discount rate.

Marginal abatement costs

A second approach to pricing carbon is the marginal abatement cost method. This method asserts that the value of damages avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.

There are two interpretations of marginal abatement costs, leading to different cost estimates. On the one hand, GHGs are a global problem: because they are persistent and well-mixed in the atmosphere, emissions anywhere affect climate change everywhere. This suggests an international perspective—identifying the marginal abatement cost on a least-cost global scenario for emission reduction. On the other hand, New England states have set their own targets for GHG emission reduction and are developing regional strategies for meeting those targets that may only include the deployment of certain technologies. This suggests a local perspective, identifying the marginal abatement cost on a local scenario for meeting regional emission reduction targets.

International perspective

Previous AESC studies (AESC 2013, AESC 2015, and AESC 2018) all arrived at the conclusion that CCS was the marginal abatement technology in many global scenarios for climate mitigation. These global scenarios often consider both electric and non-electric measures, meaning CCS is the marginal economy-wide technology. In AESC 2018, we determined this value had a total cost of $100 per short ton (in 2018 dollars), according to a 2015 meta-analysis of CCS costs.[206] The latest data assembled by NREL in its 2020 release of the ATB suggests this number has decreased since that study took place.[207] According to this study, a natural gas combined cycle (NGCC) power plant running at an average capacity factor built with CCS has an incremental cost of $29 per MWh versus a standard NGCC running at the same capacity factor (in 2018 dollars). Under this report's assumptions, a CCS system is capable of avoiding 90 percent of carbon emissions, producing an avoided emissions rate of 0.33 short tons per MWh. Dividing $29 per MWh by 0.33 short tons per MWh yields an incremental cost of $88 per short ton (in 2018 dollars). In 2021 dollars, this is a cost of $92 per short ton. This is our international perspective estimate.

Local perspective

AESC 2021 proposes two different local marginal abatement costs for New England states with different policy contexts.

[206] Edward S. Rubin, John E. Davison and Howard J. Herzog (2015), "The cost of CO_2 capture and storage," *International Journal of Greenhouse Gas Control*, https://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Rubin_et_al_ThecostofCCS_IJGGC_2015.pdf. The estimate cited here is the midpoint of the range in Table 16, line 1 (stated as $59 - $143 per metric ton in 2013 dollars).

[207] NREL (National Renewable Energy Laboratory). 2020. 2020 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Available at https://atb.nrel.gov/electricity/2020/data.php.

Derived from the electric sector

AESC 2018 proposed an electric-sector technology as the marginal abatement technology in New England, as it assumed that all end-uses would need to be electrified and then powered by zero- or low-carbon electric-sector technologies in order to achieve substantial GHG emission reductions. In AESC 2018, we determined that the most appropriate marginal abatement technology for New England was offshore wind.

After reviewing recent literature on this topic, under the AESC counterfactual paradigm, we find that offshore wind remains the best estimate from a local perspective. Conventionally, marginal abatement technologies are identified through comparative analysis of technology costs (measured in dollars-per-ton abated) and potentials (measured in total potential tons to abate). It is expensive and challenging to define a regional marginal abatement technology for four reasons:

- First, prices of technologies change over time as technologies improve and new policies come into effect.
- Second, technology potentials change over time as new data becomes available, as technologies improve, and as new resources are constructed (thereby decreasing the amount of future emissions-reducing potential).
- Third, the "demand" for future emission reductions is not always known. Some states may have defined emission reduction goals, targets, or requirements for some years, but not all years being considered. Other states may not identify emission reduction targets for the sectors of interest to AESC, or may be ambiguous in terms of how "required" these emission reductions are.
- Finally, in an ideal world, this exercise would be performed for every year being considered for analysis. This temporal aspect complicates each of the factors described above.

Given that AESC 2021 does not have the scope or time available to perform an exhaustive marginal abatement estimate, we look to the literature. One 2019 study, relying in part on cost and potentials data assembled by the Synapse Team in AESC 2018, found that in 2030 offshore wind represents about half of the overall emissions reduction potential for Massachusetts.[208] Furthermore, if this same study were performed absent the resources being tested for cost-effectiveness with AESC 2021 (e.g., future energy efficiency or electrification), we would likely find offshore wind to be the marginal resource.[209] Because of offshore wind's large resource potential, it is likely to be the marginal resource in any

[208] Stanton, E., T. Stasio, B.Woods. 2019. *Marginal Cost of Emissions Reductions in Massachusetts.* Applied Economics Clinic for the Green Energy Consumers Alliance. Available at https://static1.squarespace.com/static/5936d98f6a4963bcd1ed94d3/t/5de5363d20783a433fff5ffe/1575302718557/Marginal+Cost+of+Emissions+Reductions+in+Massachusetts_Nov+2019.pdf.

[209] Other information may be available from a forthcoming climate policy sensitivity. See Chapter 12: *Sensitivity Analysis* for more information.

number of scenarios that test the sensitivity of marginality to variables like prices, potentials, states considered to have "required" emission reductions, and year being considered for marginality.

With this under consideration, the Synapse Team performed a review of the literature to develop an up-to-date forecast of offshore wind prices over the AESC 2021 study period. In October 2020, NREL published its *2019 Offshore Wind Technology Data Update*, which contained the levelized adjusted strike prices for over 30 different offshore wind auctions across the United States and Europe.[210] The NREL strike price refers to the contract price agreed upon by the buyer and seller of energy for a given project. This price is typically tied to a specific contract length, represents what the project will be paid for the energy and other benefits, and likely includes some profit margin for the developer. In this document, NREL has adjusted all strike prices to include grid connection and development costs in order to ensure an apples-to-apples comparison across projects. NREL has also accounted for differences in contract length by converting the annual strike price to a present value. Since this report contains strike price data for projects with estimated online dates between 2020 and 2025, we used the average cost in each year to develop our price forecast.

In order to project how the cost of offshore wind could change after 2025, we referenced NREL's most recent ATB.[211] NREL releases a new version of the ATB each year as a way to track how improvements in R&D and supply chain can affect technology costs and performance assumptions. One of the metrics provided in the ATB is the levelized cost of energy. This metric uses the projected technology cost and performance to calculate the total costs as spread out over the total anticipated energy generation. NREL's moderate technology innovation scenario projects a decrease in offshore wind's levelized cost of energy over time, largely due to increasing turbine sizes and increased efficiency in the supply chain. This year-over-year cost decline was used in conjunction with the average strike price from 2025 to develop a more forward-looking trend out through 2035.[212] Figure 45 shows the offshore wind price trajectory used to calculate the marginal abatement cost over the AESC 2021 study period. Price data for Mayflower wind was adjusted based on new information pertaining to the extended investment tax credit released in January 2021.[213]

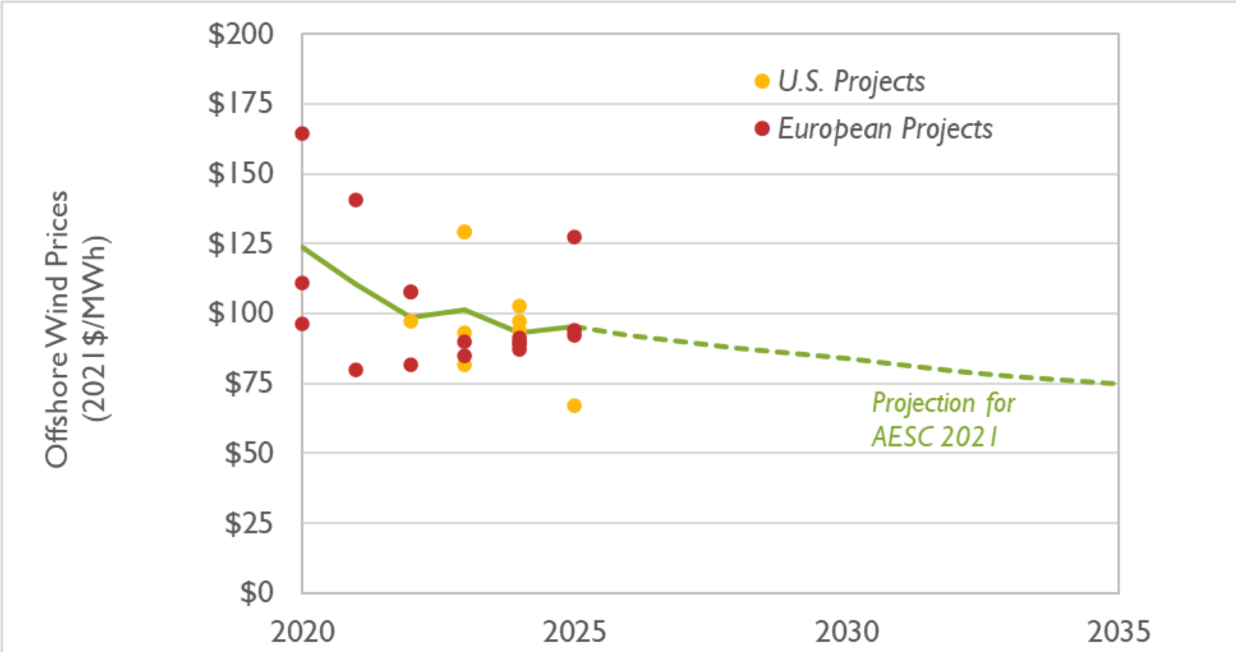
[210] NREL (National Renewable Energy Laboratory). 2020. *2019 Offshore Wind Technology Data Update.* Available at https://www.nrel.gov/docs/fy21osti/77411.pdf.

[211] NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline." Available at: https://atb.nrel.gov/electricity/2020/about.php

[212] We referenced the levelized cost of energy trajectory that assumed the "Market + Policies" financial case, a moderate technology innovation scenario, and the default technology class. The Market + Policies case considers federal tax credits and debt interest rates. Class 3 was selected as the default technology class by NREL because it "best represents the resource characteristics of near-term deployment for fixed bottom technology". See https://atb.nrel.gov/electricity/2020/index.php?t=ow for more detail.

[213] Mayflower Wind. January 8, 2021. "Mayflower Wind "Low-Cost Energy" Price Anticipated to go Even Lower Due to Unique Commitment to Pass Cost Savings of Federal Tax Credits to Customers." *Mayflowerwind.com*. Available at https://mayflowerwind.com/mayflower-wind-low-cost-energy-price-anticipated-to-go-even-lower-due-to-unique-commitment-to-pass-cost-savings-of-federal-tax-credits-to-customers/.

Figure 45. Price trajectory for offshore wind



Sources: Data from NREL, "2019 Offshore Wind Technology Data Update" and 2020 Annual Technology Baseline. Datapoint for Mayflower Wind based on updated pricing announced in a January 8, 2021 by the project developers.

After we developed the cost trajectory using the methodology described above, we subtracted the estimated energy costs from the total offshore wind price.[214] Because the amount paid for energy represents revenue to the offshore wind project owner, only the remainder is considered the abatement cost.[215] This abatement cost represents the incremental cost of this non-emitting technology. After levelizing the abatement cost stream into a present value, the cost was multiplied by the annual marginal emissions rates of described below in Table 80. The final value translates to a cost per avoided short ton of CO_2 of $125 per short ton.

In AESC 2018, the cost of avoided CO_2 was reported to be $68 per short ton in 2018 dollars or $72 per short ton in 2021 dollars. We find that the AESC 2021 cost is 75 percent higher. This cost increase is driven by three factors:

- First, in AESC 2021, we have 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.

[214] For the calculations described in this paragraph, we have subtracted the energy costs associated with Counterfactual #1.

[215] This calculation does not remove capacity payments. These are unknown for projects that are currently proposed in New England, and given the rules of the FCM, are highly dependent on the timing of retiring power plants. This cost also does not account for any additional costs related to network upgrades or storage (e.g., for balancing purposes). If these components were included, the total cost would be higher, making the cost described above a conservative estimate.

- Second, in AESC 2021, we assume 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.
- Third, the 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.

Derived from multiple sectors

AESC 2018 assumed that all end-uses would need to be electrified in order to achieve substantial GHG emission reductions. However, in some policy contexts, policymakers (including utilities and program administrators) who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050) may have another avenue to eliminate GHG emissions. In particular, end-uses in the thermal sector that are currently powered by the on-site combustion of fossil fuels could instead be powered by low- or zero-carbon variations of that same fuel. This comparison may be a necessary one in cases where policymakers are seeking to develop a complete list of comparative, politically feasible technologies that would lead to decarbonization, or in other cases where electrification is not being considered as a viable technology (e.g., under one of the counterfactuals). Under this construct, we would compare the cost of the marginal abatement technology derived from the electric sector (described above) with the cost of the marginal abatement technology derived from the thermal sector (described below). The more expensive of these two costs could then be said to be the marginal abatement cost across these two sectors.[216]

One such technology is RNG.[217] RNG is a term for natural gas that is derived from biomass or other renewable resources and is fully interchangeable with conventional natural gas. RNG can be produced through a variety of methods, including deriving biomethane from waste via anaerobic digestion or gasification, deriving hydrogen from electrolysis, and deriving synthetic natural gas from hydrogen and a renewable CO_2 source (like biomass).[218] RNG produced from each of these methods varies in both potential and costs. Of these methods, some are established technologies with decades of operating experience (e.g., extracting and purifying biomethane from biogas sources such as landfills and waste digesters), whereas other methods are still in their technological infancy (e.g., processes where electrolysis is used to produce RNG, sometimes called “power-to-gas” or “P2G”). The Synapse Team reviewed the literature to determine what an appropriate cost of RNG should be for New England.

[216] GHG emissions are of course produced from other sectors (e.g., industrial, transportation, agriculture). Because program administrators are primarily concerned with installed measures that impact the electric and thermal sectors only, we ignore costs derived from technologies in the other sectors.

[217] Other technologies, such as diesel with high biofuel contents (e.g., B100) were also considered for analysis. However, they were ultimately not included due to (a) their low availability and (b) the challenges and costs associated with converting existing furnaces and boilers to utilize this fuel. In other words, RNG can be used alongside or in place of conventional natural gas in existing heating technology; the same cannot be said for B100 and home heating oil.

[218] “The Challenge of Retail Gas in California’s Low-Carbon Future.” California Energy Commission. April 2020. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

The primary source we evaluated is a March 2020 report published by ICF on behalf of Washington Gas Light Company.[219] ICF provides an estimate of nationwide RNG production for four years (2025, 2030, 2035, and 2040) across three scenarios (conservative low, achievable, and aggressive high) for nine different types of RNG. The maximum potential in 2035 (the scope of AESC 2021) is 6 quadrillion Btu per year for the nation as a whole. This is compared to natural gas consumption in New England in the residential and commercial sectors of 9 quadrillion Btu in 2019.[220] This suggests that even if the entire country's potential for RNG were dedicated to New England, the marginal cost of RNG would be the most expensive technology available, if it were being deployed at a scale to considerably abate GHG emissions.

The ICF study identifies P2G as being the most expensive variation of RNG. This technology involves having renewable technology produce hydrogen, which is then combined with CO_2 to create methane. P2G is also the RNG variation that is least limited by available feedstocks, and thus able to meet marginal needs comparable in scale to the regional demand for natural gas.

ICF states that P2G has a production cost of about $25 per MMBtu, assuming large economies of scale. Assuming RNG derived from P2G completely replaces the consumption of natural gas (which has an emissions rate of 53 kg CO_2 per MMBtu), this translates into a cost of $471 per metric ton.[221] This value does not include the cost of CO_2 for the methanation reaction, which ICF estimates at $30 per metric ton.[222] Other estimates describe the cost of CO_2 direct air capture in the 2035 timeframe at about $60

[219] Note that the 2020 report is discussed here as it is the most recent and most comprehensive contribution from ICF on this topic.

"Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington, D.C. Metropolitan Area." ICF Resources Inc. March 2020. Available as Appendix D at https://edocket.dcpsc.org/apis/api/filing/download?attachId=101994&guidFileName=e69b6cb2-963c-4122-aca3-3b45e838b2b7.pdf.

American Gas Foundation. December 2019. *Renewable Sources of Natural Gas*. Available at https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Executive-Summary-Final-12-18-2019-AS-1.pdf.

ICF International. Last accessed March 11,2021. "Design Principles for a Renewable Gas Standard." ICF.com Available at https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/5a56701dec212d1888aa212a/1515614239606/ICF_WhitePaper_Design_Principles.pdf.

[220] Data on natural gas consumption obtained from https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm. This quantity does not include natural gas consumed in the industrial sector, electric power sector, or for pipeline and distribution use. Altogether, natural gas consumption in New England in 2019 totaled about 32 quadrillion Btu.

[221] Some types of RNG are described as having negative emission rates as they avoid upstream GHGs associated with natural gas (e.g., from production). Because P2G simply avoids the use of conventional natural gas, these emissions can be ignored. We also ignore emission reductions associated with pipeline leakage, as these emissions are not considered elsewhere in the AESC study.

U.S. Energy information Administration. February 2, 2016. "Carbon Dioxide Emissions Coefficients." Eia.gov. Available at https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[222] ICF 2020, at page 76. Units are assumed to be in metric tons. Another set of costs that are not included here are the costs of a heat sink (for the waste heat produced from methanation). Because these costs could theoretically be a benefit (i.e., the heat could be repurposed), we ascribe no cost or benefit to this component.

per metric ton.[223] Adding either of these two CO_2 costs to $471 per metric ton and performing unit conversions yields a range of $455 to 482 per short ton (in 2018 dollars). Averaging these two values and converting to 2021 dollars produces a value of $493 per short ton. Depending on the policy envisioned, it is possible that this cost could be imposed at its full value and carried through to the end of the study period, or implemented along some phase-in trajectory (e.g., evoking an RPS-like policy for natural gas). For purposes of simplification, and to match assumptions made for other marginal abatement costs, we assume that the same RNG cost is used in all analyzed years. Because this is greater than the abatement cost derived from the electric sector, this is our local perspective estimate for an abatement cost derived from multiple sectors.

Caveats to damage costs and marginal abatement costs

Both damage costs and marginal abatement costs have uncertainties. Damage costs are typically based on sophisticated climate and economic modeling, and may depend on the inputs being used or the algorithms applied. Damage costs are also sensitive to assumptions on discount rates, geographic scope, and considerations of high-risk situations. Likewise, of abatement cost modeling requires numerous assumptions on available technologies, costs, potentials, emissions reduction targets, and timescales.

8.2. Non-embedded NO_X costs

Combustion of natural gas creates NO_X emissions. NO_X contributes to ground-level ozone and smog, and a cause of respiratory illness. These emissions are reduced but not eliminated by current regulations.

As in previous AESC studies, we have conducted a review of the literature to develop an estimate of the damage cost of NO_X emissions (e.g., the cost that NO_X emissions impose on human health). As in AESC 2018, we rely on one 2015 study's published averages for the continental United States in the early 2010s.[224] Converted to 2021 dollars per short ton of nitrogen (N) (and rounded to the nearest $100), it found a low case of $7,200, a median of $32,600, and a high case of $68,800.[225] Based on molecular weights, a price per ton of N implies a lower price per ton of NO_X: 47 percent of the N price for NO, and

[223] Sutherland, B. G. (2019). Pricing CO_2 Direct Air Capture. *Joule*, Cell Press. Volume 3, Issue 7, 17 July 2019, Pages 1571-1573. https://doi.org/10.1016/j.joule.2019.06.025.

[224] U.S. Environmental Protection Agency. "Public Health benefits per kWh of Energy Efficiency and Renewable Energy in the United States: a Technical Report." Epa.gov. Available at https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

Other sources examined include Gilmore, E. A., Heo, J., Muller, N. Z., Tessum, C. W., Hill, J. D., Marshall, J. D., & Adams, P. J. (2019). An inter-comparison of the social costs of air quality from reduced-complexity models. *Environmental Research Letters*, 14(7), 074016. https://doi.org/10.1088/1748-9326/ab1ab5. These sources were not ultimately included in this review as they cover a more limited scope of NO_X impacts, or are more concerned with variations in modeling approaches of air quality, as opposed to the resultant NO_X costs themselves.

[225] Daniel J. Sobota, Jana E. Compton, Michelle L. McCrackin, and Shweta Singh (2015), "Cost of reactive nitrogen release from human activities to the environment in the United States," *Environmental Research Letters* 10, 025006. https://doi.org/10.1088/1748-9326/10/2/025006. Calculated from Table 1, assuming $1.00 in 2008 = $1.17 in 2018. Values are calculated by summing the aggregate effects from "atmospheric NO_X" from each column (low, median, and high).

30 percent for NO_2.[226] Assuming a 90/10 mix of NO and NO_2, this median value translates into a price of $14,700 per short ton of NO_X.[227]

Using the dollar-per-short ton cost described in the first study, and assuming the summer on-peak marginal NO_X emissions rate in Table 80, we find an avoided cost for NO_X equal to $0.77 per MWh.

8.3. Applying non-embedded costs

Non-embedded costs can be applied to both the electric sector and non-electric sectors. The following sections describe the approaches for each.

Electric sector

AESC 2021 embeds three electric-sector regulations in New England in its forecast of avoided energy costs: one (RGGI) is modeled regionwide, while two (310 CMR 7.74, a mass-based, declining cap on in-state CO_2 emissions, and 310 CMR 7.75, the Clean Energy Standard) apply only to Massachusetts and are used to represent a reasonable and current estimate for the cost of compliance for the Massachusetts GWSA regulations. In AESC 2021, we sum these embedded costs (all three for Massachusetts, RGGI only for the other five states), then subtract the annual values from the relevant marginal abatement cost (see Table 79).

Table 79. Interaction of non-embedded and embedded CO_2 costs.

Component description	Formula
Marginal abatement cost (including non-embedded components)	a
Non-MA allowance price (embedded components, including RGGI)	b
MA allowance price (embedded components RGGI, 310 CMR 7.74, 310 CMR 7.75)	c
Externality cost (non-MA)	d = a - b
Externality cost (MA)	e = a - c

The resulting cost stream (measured in dollars per short ton) can then be multiplied by a marginal emissions rate (measured in short tons per MWh) to be converted into dollars per MWh. In this context, a “marginal” emission rate refers to the emission rate associated with the resources that change their output (e.g., ramp up or ramp down) as more demand is added or removed from the grid.[228] There are short-run and long-run emission rates, each of which has separate implications for the resulting dollar-

[226] A one-ton 50/50 mixture of NO and NO_2 contains 770 lb of N based on molar fractions of N in both NO and NO_2. The value of the nitrogen in the one-ton mixture of the AESC NO_x will be 38.6 percent of the dollar price per ton.

[227] Fluid. Last accessed March 11, 2021. *Nitrogen oxides Formation in Combustion Processes*. Available at http://fluid.wme.pwr.wroc.pl/~spalanie/dydaktyka/combustion_en/NOx/NOx_formation.pdf. Pg. 42

[228] This can be contrasted with an “average” emissions rate, which refers to the total emissions produced by the grid over a long period of time (often a year) divided by the total generation output by the grid. This emissions rate includes many resources (e.g., nuclear, hydro) that do not economically respond to changes in demand.

per-MWh values. Short-run and long-run marginal costs may both be applied to measures that decrease electricity consumption (e.g., energy efficiency) the same way they are applied to measures that increase electricity consumption (e.g., heat pumps).

Short-run marginal emission rates

Using EnCompass, we calculate the marginal CO_2 and NO_X emission rates by comparing results in Counterfactual #1 with results in Counterfactual #2. Specifically, we calculate the change in emissions in each year, and divide that number by the change in demand. The result is the marginal emissions rate for any given year.[229] This emissions rate can then be aggregated over multiple hours to provide a set of summarized marginal emissions rates (see Table 80). Marginal CO_2 emission rates in the early periods are similar those found in other sources.[230] Marginal NO_X emission rates in the early periods tend to be lower than other sources for a number of reasons: chief among them, NO_X emission rates continue to fall as the grid relies more often on cleaner power plants and as the dirtiest power plants retire.

[229] This is the same theory used to produce marginal emissions and emission rates in U.S. Environmental Protection Agency's AVoided Emissions and geneRation Tool (AVERT).
U.S. Environmental Protection Agency. Last accessed March 11.2021. "Avoided Emissions and Generation Tool (AVERT)." *Epa.gov.* Available at https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert.

[230] For example, see Table 150 in AESC 2018 (available at https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf), Table 5-5 in ISO New England's 2018 Air Emissions Report (available at https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf), and data from U.S. EPA's AVERT model for uniform energy efficiency measures installed in New England (available at https://www.epa.gov/sites/production/files/2020-09/avert_emission_factors_09-08-20.xlsx).

Table 80. Modeled electric sector marginal emissions rates (lb per MWh)

	CO_2				NO_X			
	Winter		Summer		Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*
2021	756	791	779	799	0.09	0.21	0.14	0.11
2022	740	752	729	813	0.10	0.09	0.14	0.11
2023	732	826	663	932	0.09	0.08	0.11	0.09
2024	791	869	767	967	0.10	0.08	0.12	0.10
2025	796	881	812	966	0.07	0.07	0.12	0.10
2026	756	878	772	939	0.07	0.07	0.11	0.09
2027	682	824	760	930	0.07	0.08	0.11	0.10
2028	686	735	764	822	0.08	0.07	0.12	0.09
2029	702	718	753	794	0.08	0.07	0.11	0.08
2030	636	669	732	760	0.06	0.06	0.09	0.07
2031	648	692	723	768	0.06	0.06	0.09	0.07
2032	644	720	686	774	0.06	0.06	0.09	0.07
2033	652	702	737	788	0.06	0.06	0.08	0.07
2034	678	693	752	770	0.06	0.06	0.08	0.07
2035	691	690	761	793	0.06	0.05	0.07	0.06

Notes: We assume all four counterfactuals feature the same marginal emission rates.

This same step can be applied for both non-embedded GHG costs and non-embedded NO_X costs. Because there are no embedded NO_X prices included in AESC 2021's production cost modeling (e.g., in the same way that RGGI embeds some of the cost of CO_2 emissions), there is no preliminary Table 79-equivalent subtraction step required.[231]

These emission rates are "short-run" because they assume a single year that has no other changes to the grid other than the assumed "dummy" resource. In other words, they account for the hourly system demand for wholesale generation decreasing in response to this "dummy" resource, but do not incorporate any second-order effects. These short-run marginal emission rates are best used for analyzing emission changes over a period of less than one year.

Long-run marginal emission rates

Conversely, a long-run marginal emission rate takes these second-order effects into account. For the purposes of AESC 2021, the primary second-order effect to consider are renewable builds. These marginal emission rates are best used for analyzing emission changes over a period greater than one year. The following paragraphs provide guidance on one methodology that AESC users can apply to adjust their marginal emission rates.[232]

[231] Costs of controls or technology that limit or reduce NO_X emissions from individual power plants are not considered.

[232] Because the avoided energy, avoided capacity, and other avoided costs do not change based on the selected emissions accounting approaches, these avoided costs are independent of the AESC user choice of a long-run marginal emission rate approach.

All New England states have some kind of RPS policy in effect (see Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* for more information). Under these policies, LSEs (such as electricity utilities) must procure a quantity of RECs equal to a specified percentage of that entity's electricity sales in a particular year. In many jurisdictions, this percentage increases over time for "Class 1" markets. However, consider a hypothetical in which the percentage is flat: if electricity sales go up, then the entity will have to purchase and retire more RECs (implying the addition of more renewables to the grid). If electricity sales go down (e.g., as a result of increased energy efficiency programs) the entity will have to purchase and retire fewer RECs.[233] Because the renewables driven by these RPS policies would also displace marginal generators and decrease emissions, ignoring the effects of these policies will overestimate the emissions-reducing impacts of energy efficiency and other DSM resources.

For time periods of one year or more, the marginal emissions rate is derived from not only the marginal displaced resource, but also RPS percentage targets (which require demonstration of compliance annually). One can determine the effect of these RPS policies on the overall marginal emissions rate by calculating a weighted average of the model-derived emissions rate and the share of resources purchased to meet RPS targets. For example, consider a hypothetical state with a 50 percent Class 1 RPS target and a supporting policy to meet this obligation through long-term contracts with zero-carbon resources. In this situation, if 1 MWh of energy efficiency were deployed, load would decrease by 1 MWh, avoiding the purchase (and possibly creation) of 0.5 MWh of zero-carbon generation.[234] As a result, this 1 MWh would avoid 0.5 MWh associated with the marginal emissions rate described in Table 80, and 0.5 MWh of zero-emitting energy. We assume this methodology is applicable only to RPS categories where compliance is achieved through the retirement of RECs associated with non-emitting resources.[235]

However, renewable policies only impact the marginal emissions rate in certain circumstances:

- First, some states may have policies that require utilities to purchase renewables or other types of zero-emitting generation on an absolute MWh basis. In these circumstances, contracts for renewable energy are not linked to load, meaning that variations in load (due to energy efficiency or other DSM programs) do not have any effect on marginal emission rates. If a state only had policies of this type (i.e., with no RPS-style policies), the long-run marginal emission rates would be equivalent to the short-run marginal emission rates.

[233] Importantly, the renewable energy attributes of these MWh must be claimed in some way (i.e., the retirement of RECs) in order to ensure there is no double-counting among different entities in New England.

[234] This simplified example does not consider impacts of T&D losses.

[235] For example, there are some RPS categories where compliance is primarily achieved through the retirement of RECs associated with combined-heat-and-power plants. These plants have similar emissions rates to the systemwide marginal emission rate, and therefore do not contribute to avoided emissions.

- Second, because of the overlap among resources that qualify for both these contracting policies and RPS policies, sometimes the amount of available renewable energy exceeds the quantity required under an RPS. For example, consider a hypothetical where utilities in a state with 20 TWh are (a) required to purchase 12 TWh of renewable resources in any given year, and (b) the state also has an RPS wherein utilities must purchase and retire RECs equivalent to 50 percent of their electricity sales (10 TWh). In this hypothetical, the state's RPS policy is exceeded by 2 TWh, meaning that changes to load (short of increasing load by 2 TWh) will not have an impact on the quantity of renewables purchased by that state.

For any one state, the marginal renewable (RE) fraction that should be applied to the modeled marginal emissions rate can be calculated using the algorithm in Equation 2. The marginal RE fraction is then applied to the modeled marginal emissions rate in Equation 3 to determine the final marginal emissions rate.

Equation 2. Marginal renewable (RE) fraction

$$[A]\ Total\ RPS\ requirement\ (\%) = RPS\ Class\ 1\ \% + RPS\ Class\ 2\ \% + \cdots + RPS\ Class\ N\ \%$$

$$[B]\ Required\ RE\ as\ a\ fraction\ of\ sales\ (\%) = \frac{Contracted\ RE + Zero\ Carbon\ (RECs\ not\ resold) + Additional\ RECs\ retired\ (MWh)}{State\ electricity\ sales}$$

If [B] > [A]

Then marginal RE fraction (%) = 0%

Else marginal RE fraction (%) = [A]

Equation 3. Final marginal emissions rate

$$Final\ marginal\ emissions\ rate = Modeled\ marginal\ emissions\ rate \times (1 - marginal\ RE\ fraction)$$

In our example, [A] is equal to 50 percent. Because the total number of RECs retired is 12 TWh (all 12 TWh of RECs from the contracting policy as assumed retained, with no further RECs needed to meet the RPS policy), [B] is equal to 12 TWh divided by 20 TWh, or 60 percent. Because B is greater than A, the marginal RE fraction is zero. This makes the final marginal emissions rate equal to the modeled marginal emissions rate.

In some circumstances, if [A] and [B] are very close together, applying some quantity of demand-side measures may cause [A] to exceed [B] or vice versa. In these situations, the marginal RE fraction should be calculated separately first for (i) the quantity of demand-side measures that are under the threshold where [A] is less than [B] (or vice versa) and second for (ii) the quantity of demand-side measures that are over the threshold. Calculating the marginal emissions rate in this situation is challenging, but doable. Practically speaking, this circumstance is unlikely to occur for two interrelated reasons:

- First, based on our renewable energy market fundamentals analysis, we anticipate an RPS compliance surplus in each state, in each counterfactual, and in each study year.

REC supply and demand are expected to be closest to equilibrium during the first three years of the study period. During this time, while current-year REC supply *may* trail current-year demand in one or more years, RPS-obligated entities currently hold large 'bank balances' (which refers to excess RPS compliance that LSEs collectively already have at their disposal) which can be used to fulfill RPS obligations and therefore provide a clear signal that no incremental renewable energy builds are required. In the middle and later years of the study period, regional REC surpluses of up to 5,600 GWh *per year* are expected.

- Second, the quantity of demand-side measures would likely have to be very large to cause the positions of [A] and [B] to switch. At any given time, program administrators are likely only screening one to three years' worth of measures or programs, a quantity that is unlikely to absorb the modeled REC surpluses by itself.

In other words, because regional REC surpluses are expected throughout the study period—obviating the need for renewable energy builds beyond policy-mandated supply—in all counterfactuals, any quantity of demand-side measure deployed (whether it increases or decreases demand) is unlikely to affect the quantity of renewables built.

Some AESC users may take a state- or utility-specific approach to calculating changes in emissions that result from changes in an area's load, using an area-specific emission inventory, rather than the regionwide approach described above. For example, a state may account for emissions based only on the amount and type of RECs retired by utilities serving load in the relevant sub-regional area. For these users, procurements of fixed quantities of renewable or zero-carbon resources outside of the relevant jurisdiction may not affect the jurisdiction's emissions, and RPS policies could be considered to be binding if the area-level value of [A] exceeds [B]. In this approach and circumstance, the final marginal emission rate would be equal to (i) the modeled emissions rate multiplied by (ii) the number of RECs divided by the statewide electricity load.[236]

Non-electric sectors

The approach for the non-electric sectors is simpler. The dollar-per-ton non-embedded value is simply multiplied by the relevant non-electric emissions rate (measured in tons per MMBtu) to produce dollar-per-MMBtu values. These emission rates may be fuel- and sector-specific (see Table 17 and Table 18 for more information on non-electric emission rates). Because policies like RGGI and RPS only impact the electric sector, they should not be taken into account when calculating non-electric sector impacts (i.e., they are not embedded).

[236] This term (ii) is functionally equal to the state or sub-region's annual RPS percentage, assuming that all RECs procured to meet the annual RPS percentage are retired.

9. Demand Reduction Induced Price Effect

DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy—relative to the prices forecast in the Reference case—resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period. In some contexts, DRIPE maybe called “price suppression” or “price effect.”

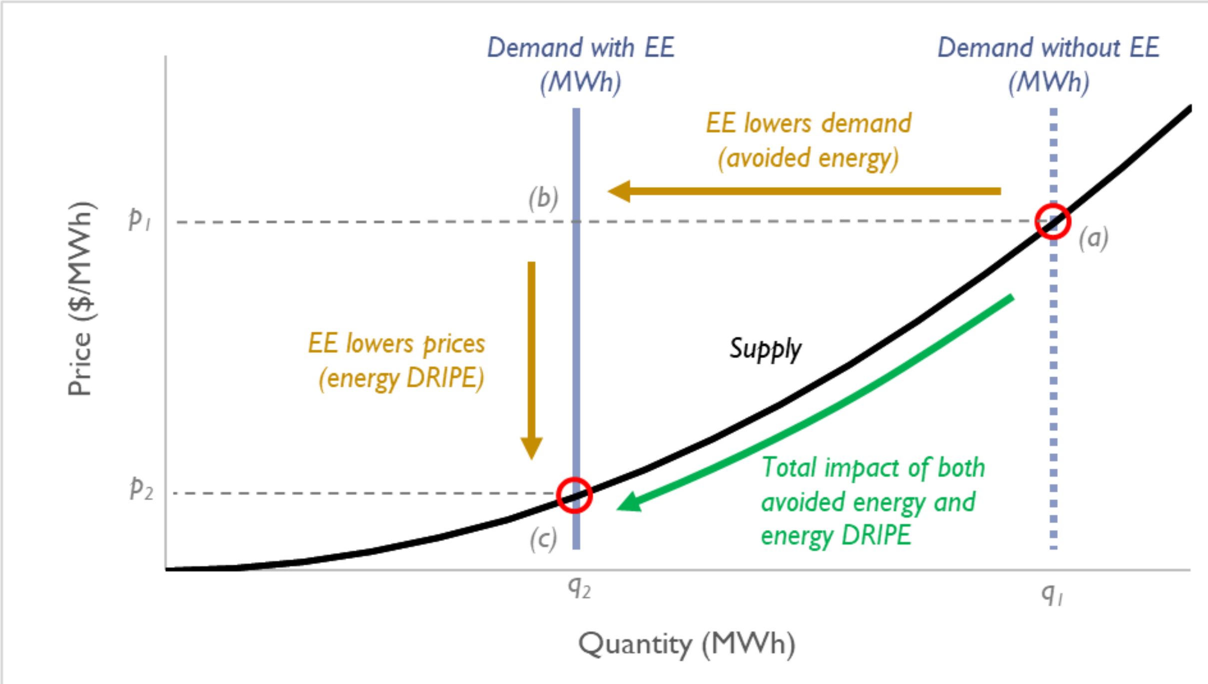
This chapter describes our results, methodology, and assumptions for energy DRIPE, capacity DRIPE, natural gas DRIPE, fuel-oil DRIPE and cross-DRIPE effects using a combination of quantitative analyses of national and New England data rather than modeling projected market conditions.

DRIPE results in AESC 2021 differ from those in AESC 2018 as a result of updated information about supply in each of the markets examined. Generally speaking, we find (a) lower energy DRIPE and capacity DRIPE values due to projections of flatter supply curves compared to AESC 2018, (b) lower natural gas DRIPE values due to lower commodity prices and flatter supply curves, and (c) lower oil DRIPE values due to changes in the underlying projection of crude oil prices. See each of the subsections below for detailed comparisons of DRIPE values in AESC 2018 and AESC 2021.

9.1. Introduction

DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period. It is a separate and distinct benefit from avoided energy, avoided, capacity, avoided natural gas, and avoided oil. Figure 46 illustrates the impact of DRIPE. Whereas avoided energy (for example) describes the benefits associated with a quantity reduction, avoided energy DRIPE describes the benefits associated with a price reduction. These effects are not double-counting—in this Figure 46, each energy DRIPE and avoided energy (yellow arrows) are separate vector components of the aggregate effect (green arrow). The total cost at point (a) is equal to p_1 x q_1, while the total cost at point (c) is equal to p_2 x q_2. If DRIPE were uncounted, the total cost would incompletely be calculated as the cost at point (b), or p_1 x q_2.

Figure 46. Example figure depicting separate and non-overlapping avoided energy and energy DRIPE effects



Note: This example figure depicts impacts in the energy market, but the principles are the same for all other DRIPE categories. This figure also uses "EE" as an example measure. DRIPE effects can be calculated for any measure (EE or otherwise), including measures that increase the demand of a commodity.

Broadly speaking, we model five categories of DRIPE in AESC.

- **Energy DRIPE:** The consumer savings from reducing load, resulting in the market price being set by a plant with a better heat rate or less expensive fuel (e.g., natural gas rather than oil). These computations hold gas prices constant, avoiding any overlap with the Electric-Gas-Electric cross-DRIPE discussed below.

- **Capacity DRIPE:** The change in state and regional electricity bills due to reductions in electric capacity prices.

- **Own-price natural gas DRIPE:** The value of reduced natural gas demand on both gas commodity prices (gas supply DRIPE) and transportation costs to New England from the production area (gas basis DRIPE).

- **Cross-DRIPE:** The value that gas reductions have on electricity prices and that electricity reductions have on natural gas prices. Cross-DRIPE is separate from, and in addition to, own-price DRIPE values. It does not double-count any benefits.

    - **Gas-to-Electric (G-E) cross-DRIPE**: The benefits to electricity consumers that result from lower gas demand reducing gas prices for electric generation.

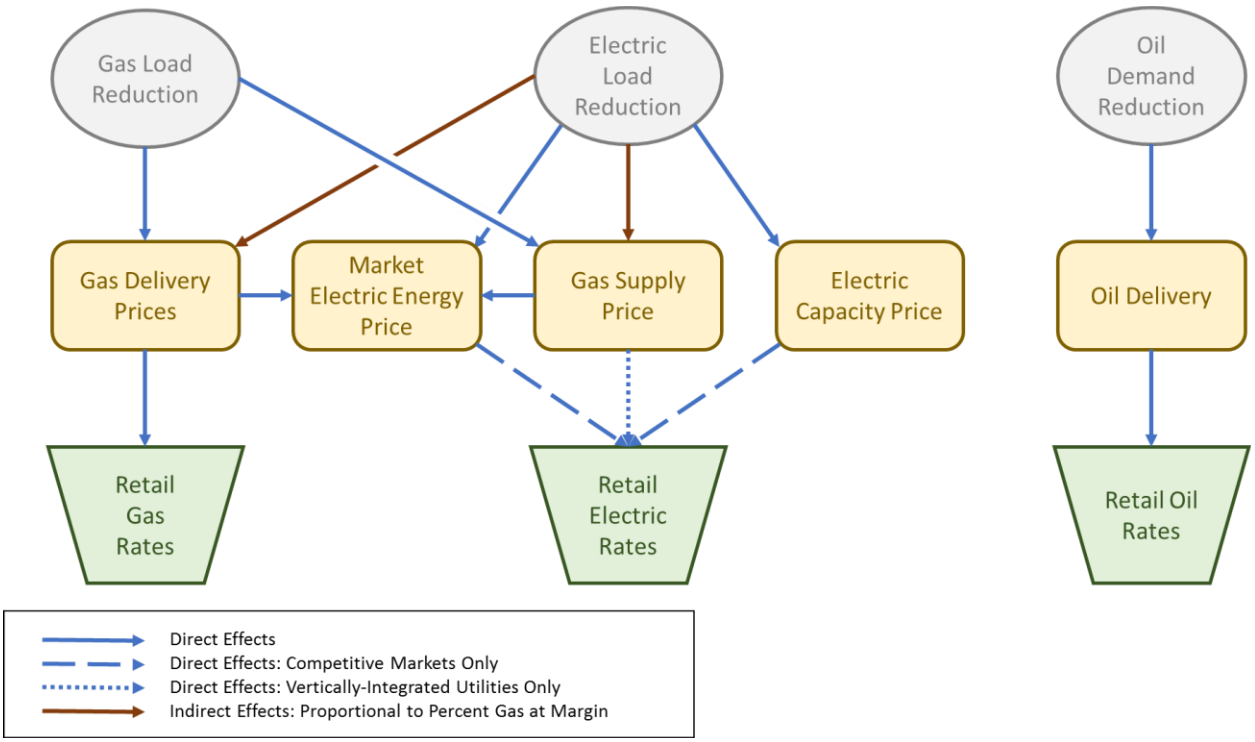
    - **Electric-to-Gas (E-G) cross-DRIPE**: The benefits to gas consumers from a reduction in electricity demand and hence gas demand for generation.

- **Electric-to-Gas-to-Electric (E-G-E) cross-DRIPE**: The benefits of reductions in electricity demand on gas prices which in turn reduce electricity prices, even if the marginal generator does not change. E-G-E DRIPE measures the electric bill savings associated with reduction in the cost of gas for the marginal price-setting power plant, resulting from the decline in natural gas usage for electricity.

- **Own-price oil DRIPE:** The value of reduced demand for petroleum products (e.g., gasoline, diesel, residual) on petroleum prices.

The interactions of DRIPE effects are shown in Figure 47.

Figure 47. DRIPE effect interactions



There are two elements to these estimates: magnitude and duration. The magnitude of DRIPE depends on market prices, market size, and the market price responsiveness. DRIPE benefits are unlikely to exist in perpetuity, however, so benefits are adjusted downward, or decayed, to reflect how other market participants respond to changes in market price over time.

Our estimates indicate that the 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 for the state or region. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

General DRIPE methodology

In AESC, DRIPE is estimated according to the following steps:

1. First, a "price shift" is calculated. This shift represents the change in price (e.g., dollars per MWh) for a change in demand (e.g., MWh). Aggregated over many data points, this price shift represents the supply curve of a particular resource. For many DRIPE categories, this is calculated using a regression, where we observe many hundreds or thousands of historical datapoints to establish a relationship between prices and demand. For other DRIPE categories, these price shifts are based on an assumed supply curve. This most notably occurs for capacity DRIPE, where there is not enough information to develop a regression from historical data.

2. Second, these price shifts are multiplied by total future market demand, so that they may then be applied to any generic change in demand. In other words, the price shift is expressed in terms of price-per-demand.[2] Multiplying the price shift by demand translates it into a price-per-demand value that can then be multiplied by a measure's anticipated savings.[237]

3. Finally, the price-per-demand value is adjusted. This may include accounting for hedged demand which has, in theory, already been purchased and is not subject to price shifts. Or, it may involve reducing benefits to account for decays in effects, or "phasing in" of effects to describe a lag in the way the market realizes these impact. Importantly, only some categories of DRIPE have these shifts applied.

Depending on the DRIPE category, these steps may be more complex or performed in a different order (in order to facilitate computation).

Price effects impact the entire region because there is only one market each for electric energy, electric capacity, and natural gas. For all the DRIPE categories described in AESC, we estimate both intra-zonal DRIPE (i.e., the benefits that accrue within a zone from load impacts within that zone, sometimes called own-zone or zone-on-zone) and inter-zonally (i.e., the benefits that accrue beyond that zone's borders in the "rest of pool"). Intra-zonal DRIPE is calculated by multiplying the price effect for a particular category of DRIPE by a single state's projected demand (rather than the regional total). Meanwhile, inter-zonal DRIPE is calculated by subtracting the intra-zonal value from the regional total.[238]

In some jurisdictions, only "intra-zonal" DRIPE benefits are used in cost-effectiveness testing. The reason may vary, but in some cases, there may be a regulatory directive to only count the benefits that accrue to a particular state's ratepayers. However, we note that the inter-zonal benefits continue to exist even if

[237] Throughout this chapter, we frequently discuss DRIPE in terms of benefits relating from savings, but DRIPE is a non-directional value that can also describe price increases resulting from increased demand. Some measures that reduce the use of one kind of fuel (e.g., natural gas) but increase use of another fuel (e.g., electricity) may end up utilizing nearly all the DRIPE categories described in this chapter.

[238] An equivalent mathematical operation would be to multiply the price shift by the regional total demand less the demand for the state in question.

they are not counted in a measure's cost-effectiveness test. We also note that these benefits are not counted by any other state.

The remaining text of this chapter describes the specific methodology used to generate DRIPE benefits for each category of DRIPE.

9.2. Electric energy DRIPE

A reduction in electricity demand should reduce wholesale energy prices, which benefits all market participants. This section describes the AESC 2021 methodology and assumptions for electric energy DRIPE, discusses the benefits and detriments of various model forms, and presents our estimates of energy DRIPE. Energy DRIPE values are presented in two ways: first, by zone, month, and period; second for the "top" 100 load or price hours. The monthly values provide DRIPE estimates for programs targeting baseline reductions while the "top" hour assessments provide estimates for more targeted applications.

Our estimates of electric energy DRIPE follow the same approach used in previous AESC studies from 2009 to 2018. Generally speaking, we conduct a set of regressions of historical zonal hourly market prices against zonal and regional load to develop elasticities. Then, we estimated the timing and duration of benefits based upon the following market realities:

1. The reductions in wholesale prices are assumed to flow through to customers as existing contracts and other resources (legacy resources, renewable contracts, basic-service and other default contracts, direct contracts with marketers) expire.
2. Customers will respond to lower energy prices by using somewhat more energy.[239]
3. The generation market will respond to sustained lower prices by some combination of retiring and de-rating existing generating capacity and delaying new resources that reduce market energy prices (such as gas combined-cycle units and high-efficiency combustion turbines).
4. Lower loads will tend to result in lower acquisition mandates under renewable and other alternative-energy standards that are stated as a percentage of energy sold.

Regression model selection

AESC 2021, like AESC 2018, estimates the magnitude of wholesale energy market DRIPE by year by conducting a set of regressions of historical zonal hourly market prices against regional load. This top-down approach assumes that there is an underlying relationship between prices and loads which can be

[239] Other factors (e.g., purchases of renewables, transmission construction, grid modernization, recovery of energy-efficiency costs) may simultaneously raise prices. The energy DRIPE considers only the marginal effect on market energy prices on retail prices and hence usage.

represented using a single equation. This approach has the benefit that it is easy to understand and that it captures the key features of the system transparently.

Regressions also have the benefit of modeling the average relationship between price and demand and providing structure to heterogeneous data. Periods with similar demand often have very different prices. Price dispersion is a product of an uncertain system that contains dynamic unit commitment decisions as well as a host of other stochastics such as generator-forced outages or transmission constraints. By assessing all system price and demand data, it is possible to capture both structural trends as well as uncertain events that occurred in past years.

In prior AESC studies, we considered many functional forms to describe the relationship between zonal prices and loads. We tested the significance of variables related to ISO system performance (e.g., capacity surplus, maintenance), system implied heat rate, and zonal and regional loads. After considering these candidate variables and various functional forms, we settled on a polynomial model to characterize the relationship between zonal prices and loads. The model, described in Equation 4, relates zonal price to ISO-wide demand and to natural gas prices.

Equation 4. Regression equation relating zonal electric energy prices to ISO demand and natural gas prices

$$LMP_{Zone} = \beta_0 + \beta_1 Demand_{ISO} + \beta_2 Demand_{ISO}{}^2 + \beta_3 Demand_{ISO}{}^3 + \beta_4 Price_{NG}$$

Equation 4 describes a cubic function. A cubic function allows for a "hockey stick"-like profile where prices increase slowly at first, then quickly during high load periods. For example, at the extreme right side of the supply curve (e.g., when the market's marginal unit might switch from a gas peaker to a natural gas-fired combined cycle unit), prices will increase by approximately 30 percent even though demand might only increase a few MW. In the middle of the offer stack, by contrast, switching from a more efficient gas combined cycle to a slightly less efficient one will only increase prices by a few percent. In Equation 4, changes in natural gas prices shift the overall curve up or down but do not skew the shape of the curve itself. This polynomial model offers five advantages over other assessed models:

1. **Non-linearity** that depicts very high prices at high load times and flatter prices under lower loads
2. **Explicit control for natural gas prices**, which is a major driver of winter price volatility
3. Significantly **better goodness-of-fit** compared to linear models (e.g., R^2 or sum-of-squared errors)
4. **Single functional form** for all zones, months, and periods
5. **Simple formulation**, where only key attributes are included

Note that the "ISO Demand" described Equation 4 is <u>not</u> the total ISO-wide demand for electricity. Instead, this variable is perhaps better described as "net demand," which is calculated by subtracting hourly wind, solar, and nuclear output from gross demand reported by ISO New England. Wind and solar vary throughout the day predictably (especially for solar) and less predictably (as a function of weather).

Nuclear output is quite even most days, but is sometimes reduced or eliminated due to planned and unplanned outages. None of these generators are subject to load- or price-based dispatch, since they self-schedule or bid into ISO New England's energy market at very low (in the case of wind, even negative) prices.[240] As a result, we remove the MWh contribution of these non-price-responsive generators from our "ISO Demand" variable.

In AESC 2021, we utilize data from January 2018 through December 2019 as the basis for our regressions.[241] Figure 48 plots actual price and demand data (in blue) against predicted data (in red) estimated using Equation 4 for one illustrative region and period. A similar regression was performed for nine regions (ISO-wide, Connecticut, Maine, New Hampshire, Rhode Island, Vermont, SEMA, NEMA, and WCMA), and for 24 time periods (one off-peak period and one on-peak period for each month).[242]

[240] In earlier AESC studies, we also examined the impact of removing the hourly contribution of other resource types from the regression. Availability of other generation may also affect market energy prices, but the relationship between price and output is complicated. The dispatch of thermal plants is driven by loads and energy prices; commitment of steam and combined-cycle plants is driven by forecast loads and prices; and hydro is scheduled within the week and the day to minimize costs of energy and reserves. It is therefore difficult to determine whether a plant is not running (1) because it is not available, (2) because energy price is below the plant's energy bid, or (3) because it is being held back as reserve (especially in the case of hydro and fast-start combustion turbines) or to meet higher loads expected later in the hydro operating cycle. The output of most fossil units can be determined from EPA's Air Market Programs dataset, and ISO New England provides total daily capacity that is unavailable due to outages or failure to commit in the day-ahead market, but these sources do not provide enough detail to determine why particular units are not operating. In any event, the regression results are very similar whether gross load or net load is used in Equation 4, reducing the usefulness of any additional complexity.

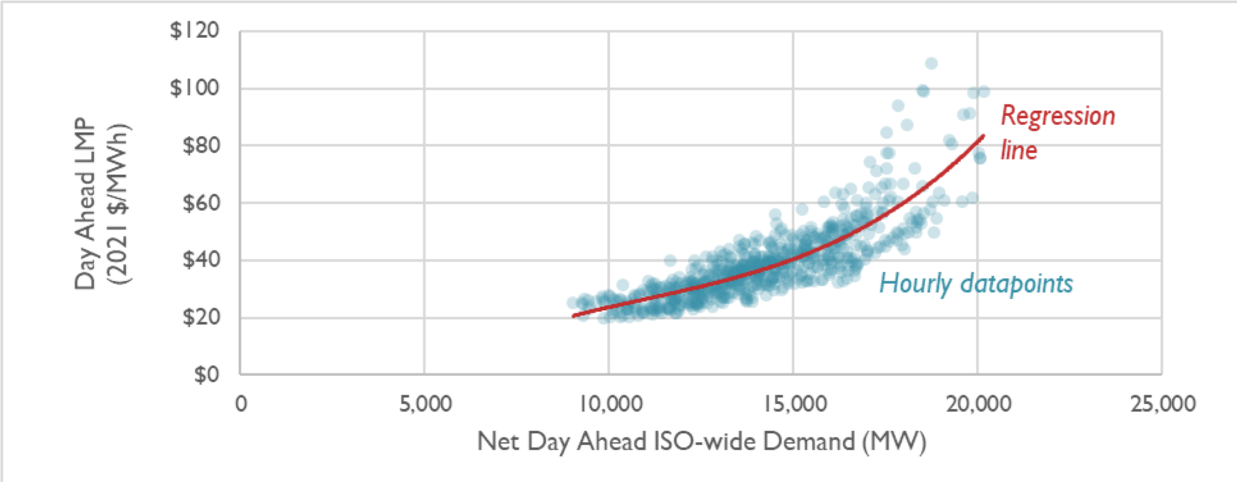
[241] This time period spans 17,520 datapoints, which provides our regressions with sufficient detail to accurately predict the relationship between prices and loads. Hourly energy price data and gross load data was obtained from ISO New England (ISO New England. 2019. *ISO new England Public*. Available at https://www.iso-ne.com/static-assets/documents/2019/02/2019_smd_hourly.xlsx) and (ISO New England. 2018. *ISO New England Public.* Available at https://www.iso-ne.com/static-assets/documents/2018/02/2018_smd_hourly.xlsx)

Sub hourly data on ISO New England's fuel mix was downloaded from ISO NE (ISO New England. Last accessed March 11, 2021. "Dispatch Fuel Mix." *Iso-ne.com*. Available at https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/gen-fuel-mix) then averaged to produce hourly results for wind, solar, and nuclear generation. Daily data on delivered prices to Algonquin Citygate were obtained from (NGI. 2021. "Algonquin Citygate Daily Natural gas Price Snapchat." Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/NEAALGCG/)

For points with very low zonal LMP, elasticities are very large. This is a byproduct of the modeling and elasticity calculation, not of any structural phenomenon. When LMP is $0/MWh, the elasticity is infinite. We exclude calculated point elasticities when zonal prices are less than $5/MWh. These exclusions occur very rarely—for the ISO New England region, for example, there is one such hour.

[242] A similar approach is used to calculate regressions for "top" hours, for use in DSM measures that do not operate the entire year but are instead targeted at certain hours. Rather than 24 periods, we calculate regressions for 374 periods for all 9 regions. This includes 68 summer off-peak regressions, 58 summer on-peak regressions, 132 winter off-peak regressions, and 116 winter on-peak regressions. Each of these batches of regressions is divided in half into regressions that span "Top Load" and "Top LMP" hours. Within Summer, On-Peak, Top Load (for example), there exists regressions that cover the top 50 hours (sorted by ISO-wide demand), the top 100 hours, the top 150 hours, and so on. Asymmetry in number of regressions across different time slices (summer, winter, on-peak, and off-peak) is due to differences in the number of hours included within each time slice.

Figure 48. Illustrative regression for WCMA, July on-peak hours



Note: This chart is shown for illustrative purposes only. To plot the red, fitted line in the figure, we assume a daily price of $0 per MMBtu for natural gas (as multivariate regression cannot be displayed in a two-dimensional chart). This differs from our actual analysis where different natural gas prices were used for each point. Final DRIPE calculations use monthly timeframes instead of quarterly; different zones have different price/load pairs.

In general, the model produces a good fit (R^2 above 0.7) for 87 percent of the 216 regressions (24 periods X 9 regions). The remaining regressions feature R^2 values that range from 0.5 to 0.7. These poorer fits are typically found during off-peak or spring and fall time periods. The average R^2 value for the gross-demand model, across all zones, months, and periods is 0.8, and the minimum R^2 across all zones/periods/months is 0.5.

Calculating elasticities from the regression

After establishing a functional form to model the relationship between price and demand, we then estimate elasticities using these regressions. For each regression, we first calculate the derivative of the polynomial regression model (Equation 4) with respect to demand:

Equation 5. Calculation of regression derivative

$$Instantaneous\ slope = \frac{\partial LMP_{Zone}}{\partial Demand_{ISO}} = \beta_1 + 2\beta_2 Demand_{ISO} + 3\beta_3 Demand_{ISO}{}^2$$

For each hour within a regression, this derivative describes how price would change in each hour for a small change in demand. Next, we apply Equation 6 to describe the elasticity for each hourly data point (e.g., an estimate of the percent change in price per percent change in demand).

Equation 6. Calculation of elasticity

$$Elasticity = \frac{\%\ change\ in\ price}{\%\ change\ in\ demand} = \frac{Instantaneous\ slope\ of\ price\ relative\ to\ demand}{Hourly\ electricity\ price} \times Hourly\ demand$$

Each of the resulting elasticities are then aggregated into a single load-weighted elasticity for each regression. This average elasticity represents the average price response to a small change in demand for a given zone, season, and period. Electric energy DRIPE elasticities are presented in Table 81 by zone, month, and period.[243]

Table 81. Energy DRIPE elasticities

Period	Month	ISO NE	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA
Annual		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Off-peak	**1**	2.3	2.4	2.3	2.3	2.2	2.2	2.2	2.2	2.3
	2	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	3	1.1	1.2	1.1	1.1	1.1	1.0	1.1	1.1	1.1
	4	1.0	1.0	1.0	1.0	0.9	1.1	1.4	0.9	0.9
	5	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7
	6	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7
	7	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.0
	8	1.2	1.2	1.2	1.2	1.2	1.1	1.2	1.2	1.2
	9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	10	1.1	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
	11	1.4	1.5	1.4	1.4	1.3	1.3	1.4	1.4	1.4
	12	1.4	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4
On-peak	**1**	2.7	2.7	2.6	2.7	2.7	2.7	2.7	2.7	2.7
	2	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	3	1.1	1.2	1.1	1.2	1.1	1.1	1.2	1.1	1.1
	4	0.9	1.1	1.0	1.0	0.9	0.9	0.9	0.9	0.9
	5	0.9	1.0	0.9	0.9	0.9	0.9	1.0	0.9	0.9
	6	0.7	0.6	0.7	0.7	0.8	0.7	0.7	0.7	0.7
	7	1.7	1.6	1.6	1.6	1.7	1.7	1.7	1.6	1.7
	8	2.1	2.0	2.1	2.1	2.1	2.2	2.2	2.1	2.1
	9	1.1	1.1	1.1	1.1	1.1	1.2	1.4	1.1	1.1
	10	1.5	1.6	1.6	1.6	1.5	1.6	1.7	1.5	1.5
	11	1.8	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	12	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.4	1.5

Note: Elasticities for Connecticut subregions (Southwest CT and Other CT) are assumed to be equal to the Connecticut-wide elasticity. A Massachusetts-wide elasticity is calculated based on a weighted average of the demand for the three subregions. These values are available in the AESC 2021 User Interface.

The results are stable across zones but vary by month and period. The modest spread in elasticity values by zone indicates zonal prices are strongly correlated with system load. On an annual basis, a 1.0 percent reduction in demand yields a 1.4 percent reduction in price. Depending on the month, a 1.0 percent

[243] We also calculate elasticities for "top" hours (described in footnote 242) using an analogous methodology to the one described here. These elasticities are not shown in this report due the large size of the table, but may be found in the *AESC 2021 User Interface*.

reduction in load throughout New England results in a 0.7 to 2.3 percent reduction in off-peak price, and a 0.7 to 2.7 percent reduction in peak price.

Comparison with AESC 2018

Table 82 describes the summary statistics from Table 81, and compares the results with analogous values from AESC 2018. Elasticities in AESC 2021 are generally lower due to differences in years analyzed (AESC 2018 estimates regressions based on data from September 2015 through August 2017, while AESC 2021 uses data for January 2018 through December 2019), and minor modifications to the elasticity algorithm.

Table 82. Comparison of energy DRIPE elasticities, AESC 2018 and 2021

		AESC 2018			AESC 2021		
		Min	*Median*	*Max*	*Min*	*Median*	*Max*
Annual		1.81	1.83	1.87	1.35	1.36	1.40
Winter	On-peak	1.95	2.35	2.59	0.87	1.38	2.71
	Off-peak	1.77	1.91	2.31	0.72	1.18	2.35
Summer	On-peak	0.98	1.81	1.94	0.65	1.50	2.22
	Off-peak	1.49	1.50	1.61	0.72	1.00	1.21

Calculating energy DRIPE

Next, we apply the above elasticities to hourly prices and loads to calculate the DRIPE benefit for any 1 MWh reduction in load. Conceptually, the value of DRIPE is equal to the change in price that results from a 1 MWh reduction in load, multiplied by the amount of load that benefits from that reduction in price.

We calculate the value of DRIPE both intra-zonally (i.e., the benefits that accrue within a zone from load impacts within that zone) and inter-zonally (i.e., the benefits that accrue beyond that zone's borders in the "rest of pool"). Equation 7 describes the calculation for intra-zone DRIPE, while Equation 8 describes the calculation for inter-zone DRIPE. Intrazonal and interzonal values are added to determine the total DRIPE effect.

The first term in Equation 7 calculates the change in zonal price given a change in ISO demand. It is multiplied by the load in Zone Z to calculate the collective benefit of that price reduction. Equation 8 is similar, but reflects how the demand reduction in Zone Z reduces prices in all other zones.

As in prior AESC studies, we assume that the value of DRIPE is reduced in two ways:

- First, rather than relying on the full energy demand values, we instead rely only on the unhedged portion of demand to calculate energy DRIPE. This is the portion of demand that has not already been purchased through long-term contracts.
- Second, we assume that the DRIPE effect decays over time. This is a series that aggregates expected effects related to resources responding to changes in prices, demand elasticity, and binding RPS policies.

Each of these two effects are described more in the subsequent subsection.

Intrazonal DRIPE values are roughly proportional to the percentage of ISO load in a given zone. Zones with less load will have lower zone-on-zone energy DRIPE values than zones with higher load. For example, Maine accounts for roughly one-fifth as much load as Massachusetts and has a zone-on-zone DRIPE value approximately one-fifth as large.[244] Conversely, interzonal estimates are approximately proportional to the difference between ISO load and zonal load. Zones with lower load will have higher zone-on-Rest-of-Pool values.

Equation 7. Value of intra-zonal electric energy DRIPE

$$DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z \\ Period\ P}} = \left[\frac{\varepsilon_{\substack{Zone\ Z \\ Period\ P}} P_{\substack{Zone\ Z \\ Period\ P}}}{Q_{\substack{ISO \\ Period\ P}}} \times Q_{\substack{Zone\ Z \\ Period\ P}} \right] \times D$$

Equation 8. Value of inter-zonal electric energy DRIPE

$$DRIPE_{\substack{Rest-of-Pool\ |\ Zone\ Z \\ Period\ P}} = \frac{(1-\delta)_{Period\ P}}{Q_{\substack{ISO \\ Period\ P}}} \sum_{\substack{x \in Zones \\ x \neq Zone\ Z}} \varepsilon_{\substack{x \\ Period\ P}} P_{\substack{x \\ Period\ P}} Q_{\substack{x \\ Period\ P}}$$

Where:
ε is elasticity
P is the zonal market energy price ($/MWh)
$Q_{Zone\ Z}$ is zonal load less hedged supply (i.e., "unhedged load")
Q_{ISO} is ISO energy load
D is the aggregate decay effect

Energy DRIPE reductions

We assume that the value of energy DRIPE is reduced due to (a) some portion of energy purchased being bought outside the spot market for energy (i.e., hedged) and (b) a decay factor. The following subsections describe the assumptions underlying each of these effects.

Hedging assumptions

Substantial energy is purchased months or up to several years in advance of delivery, through utility contracting for standard service or a third-party contract. Hence, we assume energy DRIPE benefits are calculated only using the share of demand that is unhedged (i.e., the share that is purchased on the energy spot market). Our assumptions on energy hedging are based on four factors:

1. **Investor-owned utility contracts.** These contracts include pre-restructuring legacy contracts, post-restructuring reliability contracts in Connecticut, renewables purchases, and pending purchases from Hydro Québec.[245]

[244] There are subtle differences that make comparison inexact because DRIPE also depends on zonal elasticity and hedging estimates.

[245] Data on these contracts is obtained from utility IRPs and FERC Form 1.

2. **Hedging in Vermont**. Vermont is the sole remaining New England state that is vertically integrated statewide. Based on the 2018 IRP for Green Mountain Power, we assume that all utilities in Vermont have about 60 percent of their energy hedged in all years.[246]

3. **Hedging of vertically integrated energy in the other five New England states**. The resources owned or under contract to the vertically-integrated utilities (various mixes of municipals and coops in the other five states) are estimated based data from EIA 861.[247] Because exact data on hedged energy is difficult to compile, we assume that all load related to vertically integrated utilities (outside Vermont) are 50 percent hedged in all years.

4. **Short term contracts.** In addition to long-term hedging, some load is also subject to short-term contracts. Based on our knowledge of the procurement policies for standard service, the length of third-party contracts, and information provided by some of the participating utilities, we assume that 50 percent of energy is pre-contracted for the year of measure installation, 20 percent in the following year, and 10 percent in the third year. Depending on the measure vintage selected, this assumption is shifted by one year or more.

Table 83 depicts the aggregate unhedged share of energy by year in Counterfactual #1.

[246] The 2018 IRP of Green Mountain Power (which serves the majority of Vermont load) reports 70 percent of its energy comes from owned resources and long-term contracts. The price of the 24 percent of GMP’s energy supply that came from Vermont’s long-term contract with Hydro Québec varies in undisclosed part with market prices, so perhaps 60 percent of GMP’s energy supply is price hedged. We assume all other utilities in Vermont use the same percentage of hedged energy.

[247] EIA Form 861, 2015-2019. Available at https://www.eia.gov/electricity/data/eia861/.

Table 83. Percent of load assumed to be unhedged in Counterfactual #1

Year	ISO	CT	MA	ME	NH	RI	VT
2021	40%	27%	45%	47%	45%	46%	20%
2022	63%	43%	70%	75%	72%	73%	33%
2023	75%	54%	79%	94%	90%	91%	41%
2024	68%	48%	69%	91%	90%	76%	41%
2025	63%	38%	64%	88%	90%	73%	41%
2026	61%	39%	60%	88%	90%	73%	41%
2027	62%	43%	61%	89%	90%	73%	41%
2028	63%	46%	62%	89%	90%	74%	41%
2029	64%	47%	62%	89%	90%	74%	41%
2030	66%	55%	63%	89%	90%	75%	41%
2031	71%	76%	64%	90%	91%	75%	41%
2032	72%	76%	64%	90%	91%	76%	41%
2033	72%	77%	65%	90%	91%	76%	41%
2034	73%	77%	65%	91%	91%	77%	41%
2035	73%	77%	66%	91%	91%	77%	41%

Note: Because total energy demand varies for each counterfactual, and because assumptions on contracted MWh are fixed, these percentages vary for each counterfactual. See the AESC 2021 User Interface for detail on each counterfactual.

Decay assumptions

We assume three factors tend to reduce energy DRIPE as time passes after the initial effect on market prices:

1. **Resources respond to changes in prices.** Owners of existing generating capacity would tend to allow their energy-producing assets to become less efficient and less reliable as low energy prices make continued operation of the units less attractive, leading to more outages and higher market-clearing prices.

2. **Demand elasticity.** Over time, customers might respond to lower energy prices by using somewhat more energy, pushing prices back up somewhat. We assume demand elasticities that start at 3 percent in 2021 and increase to 8 percent by 2026, where they are sustained through the study period.[248]

3. **Impact from binding RPS policies. F**or every megawatt-hour not required due to energy efficiency, generation service providers will not need to procure a fraction of a REC from new renewable resources, assuming that these policies are “binding” (i.e., drive construction of new renewable resources in New England).[249] We assume that reducing load under conditions where RPS policies are binding will generally result in fewer renewables being built, partially offsetting the reduction in energy load. This percentage varies by state, year, and counterfactual.

[248] Elasticities are derived from Paul, A., et al. "A partial adjustment model of U.S. electricity demand by region, season, and sector." Resources for the Future. Published April 2009.

[249] For more discussion on binding RPS policies, see Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* and Section 8.3: *Applying non-embedded costs*.

We calculate the aggregate decay effect in each year as the product of (a) one less the percent of load that is binding under the state's RPS policies, (b) one less the demand elasticity factor, and (c) one less the resource fade-out factor. This effect is shown in Table 84, for Counterfactual #1, for measures installed in 2021.

Table 84. Energy DRIPE decay factors for measures installed in 2021 in Counterfactual #1

Year	ISONE	CT	MA	ME	NH	RI	VT
2021	93%	96%	91%	96%	93%	96%	88%
2022	90%	93%	88%	93%	91%	93%	85%
2023	88%	92%	86%	92%	89%	92%	82%
2024	87%	90%	84%	90%	87%	90%	79%
2025	85%	88%	82%	88%	85%	88%	76%
2026	82%	85%	80%	85%	83%	85%	73%
2027	78%	82%	76%	82%	79%	82%	69%
2028	73%	76%	71%	76%	74%	76%	63%
2029	66%	69%	64%	69%	67%	69%	56%
2030	54%	57%	52%	57%	55%	57%	46%
2031	37%	39%	36%	39%	38%	39%	31%
2032	0%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	0%	0%	0%	0%
2035	0%	0%	0%	0%	0%	0%	0%

Note: This decay schedule will vary for measures installed in other years, under other counterfactuals. See the AESC 2021 User Interface for detail on each counterfactual.

Energy DRIPE values

After combining the effects of the price shifts, unhedged demand, and decay, we are able to calculate the energy DRIPE benefits. Table 85 provides 15-year levelized energy DRIPE benefits for efficiency measures installed in 2021 using Equation 7 and Equation 8. These values may be multiplied by a MWh quantity (e.g., energy savings from energy efficiency or energy increases from electrification) to estimate the resultant DRIPE impact in dollars. Values are shown for measures installed in 2021; values for measures installed in other years may be calculated using the *AESC 2021 User Interface*.

Table 85. Energy DRIPE values for 2021 installations (2021 $ per MWh) for Counterfactual #1

	Year	Intrazonal (Own Zone)						Interzonal (Rest-of-Pool)					
		CT	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Winter off-peak	2021	$3.01	$9.25	$2.39	$2.11	$1.37	$0.42	$15.64	$9.09	$16.24	$16.45	$17.22	$18.11
	2022	$5.50	$16.68	$4.38	$3.91	$2.54	$0.77	$28.46	$16.72	$29.55	$29.89	$31.33	$32.96
	2023	$6.76	$18.66	$5.41	$4.82	$3.13	$0.93	$33.19	$20.59	$34.50	$34.92	$36.69	$38.71
	2024	$6.23	$16.75	$5.41	$4.98	$2.69	$0.94	$30.99	$19.82	$31.79	$32.06	$34.41	$35.98
	2025	$4.81	$15.49	$5.21	$4.93	$2.54	$0.92	$29.27	$18.00	$28.89	$29.01	$31.46	$32.89
	2026	$4.69	$13.99	$5.06	$4.76	$2.46	$0.87	$27.32	$17.44	$26.96	$27.11	$29.46	$30.86
	2027	$4.89	$13.30	$4.79	$4.49	$2.33	$0.80	$25.92	$16.91	$26.01	$26.17	$28.38	$29.70
	2028	$5.09	$13.07	$4.71	$4.40	$2.29	$0.77	$25.44	$16.84	$25.81	$25.98	$28.12	$29.43
	2029	$4.80	$12.29	$4.42	$4.10	$2.15	$0.70	$23.87	$15.77	$24.24	$24.43	$26.41	$27.65
	2030	$4.61	$10.27	$3.69	$3.40	$1.79	$0.57	$19.93	$13.71	$20.82	$20.99	$22.63	$23.67
	2031	$4.45	$7.23	$2.60	$2.38	$1.26	$0.39	$14.04	$10.80	$15.82	$15.96	$17.10	$17.84
Winter on-peak	2021	$3.94	$11.92	$3.04	$2.72	$1.79	$0.55	$20.13	$11.76	$21.00	$21.25	$22.21	$23.37
	2022	$6.64	$19.80	$5.12	$4.64	$3.07	$0.92	$33.75	$19.91	$35.22	$35.56	$37.21	$39.19
	2023	$7.78	$21.14	$6.03	$5.45	$3.61	$1.06	$37.56	$23.41	$39.25	$39.65	$41.59	$43.93
	2024	$7.17	$18.96	$6.01	$5.62	$3.10	$1.07	$35.01	$22.46	$36.12	$36.34	$38.92	$40.74
	2025	$5.52	$17.51	$5.78	$5.56	$2.92	$1.04	$33.01	$20.35	$32.76	$32.82	$35.51	$37.17
	2026	$5.54	$16.26	$5.78	$5.52	$2.92	$1.02	$31.70	$20.30	$31.47	$31.56	$34.23	$35.89
	2027	$6.00	$16.07	$5.68	$5.41	$2.87	$0.98	$31.25	$20.45	$31.56	$31.65	$34.25	$35.90
	2028	$5.81	$14.67	$5.18	$4.92	$2.62	$0.87	$28.49	$18.93	$29.09	$29.20	$31.54	$33.05
	2029	$5.39	$13.49	$4.79	$4.52	$2.37	$0.78	$26.16	$17.40	$26.74	$26.87	$29.06	$30.41
	2030	$5.20	$11.31	$4.01	$3.76	$1.99	$0.64	$21.92	$15.19	$23.06	$23.19	$25.00	$26.14
	2031	$5.02	$7.95	$2.82	$2.63	$1.39	$0.44	$15.43	$11.98	$17.53	$17.65	$18.90	$19.71
Summer off-peak	2021	$1.60	$4.90	$1.10	$1.05	$0.78	$0.20	$8.07	$4.62	$8.56	$8.59	$8.88	$9.42
	2022	$2.38	$7.17	$1.65	$1.58	$1.17	$0.30	$11.95	$6.92	$12.65	$12.68	$13.12	$13.93
	2023	$2.87	$7.86	$2.00	$1.91	$1.42	$0.35	$13.65	$8.36	$14.49	$14.52	$15.06	$16.04
	2024	$2.81	$7.49	$2.12	$2.09	$1.29	$0.38	$13.47	$8.49	$14.14	$14.11	$14.93	$15.77
	2025	$2.18	$6.98	$2.06	$2.09	$1.23	$0.37	$12.81	$7.74	$12.93	$12.84	$13.73	$14.49
	2026	$2.12	$6.27	$1.98	$2.00	$1.18	$0.35	$11.87	$7.46	$12.00	$11.92	$12.77	$13.51
	2027	$2.22	$6.02	$1.90	$1.91	$1.13	$0.33	$11.38	$7.31	$11.69	$11.63	$12.43	$13.14
	2028	$2.44	$6.23	$1.96	$1.96	$1.17	$0.33	$11.76	$7.68	$12.22	$12.17	$12.98	$13.73
	2029	$2.30	$5.84	$1.83	$1.82	$1.09	$0.30	$11.00	$7.16	$11.44	$11.40	$12.15	$12.85
	2030	$2.24	$4.95	$1.56	$1.54	$0.92	$0.25	$9.32	$6.33	$9.97	$9.95	$10.58	$11.17
	2031	$2.16	$3.49	$1.10	$1.07	$0.65	$0.17	$6.57	$5.02	$7.59	$7.58	$8.02	$8.44
Summer on-peak	2021	$2.89	$8.79	$1.81	$1.83	$1.46	$0.35	$14.35	$8.16	$15.39	$15.32	$15.73	$16.78
	2022	$4.03	$12.12	$2.55	$2.61	$2.07	$0.48	$19.99	$11.48	$21.42	$21.29	$21.88	$23.37
	2023	$4.46	$12.18	$2.83	$2.89	$2.29	$0.53	$20.89	$12.72	$22.47	$22.34	$22.99	$24.64
	2024	$4.40	$11.77	$3.04	$3.20	$2.12	$0.57	$20.89	$13.06	$22.20	$21.96	$23.09	$24.51
	2025	$3.45	$11.07	$2.97	$3.22	$2.03	$0.57	$20.02	$11.98	$20.48	$20.15	$21.39	$22.72
	2026	$3.55	$10.49	$3.03	$3.27	$2.07	$0.56	$19.58	$12.20	$20.08	$19.76	$21.01	$22.36
	2027	$3.93	$10.61	$3.06	$3.28	$2.08	$0.55	$19.76	$12.60	$20.59	$20.29	$21.53	$22.90
	2028	$3.79	$9.66	$2.78	$2.97	$1.89	$0.49	$17.97	$11.64	$18.94	$18.67	$19.79	$21.04
	2029	$3.58	$9.08	$2.61	$2.77	$1.78	$0.45	$16.85	$10.90	$17.79	$17.55	$18.58	$19.76
	2030	$3.51	$7.72	$2.22	$2.34	$1.51	$0.37	$14.33	$9.70	$15.57	$15.38	$16.25	$17.25
	2031	$3.44	$5.52	$1.59	$1.66	$1.08	$0.26	$10.26	$7.81	$12.03	$11.91	$12.52	$13.24

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

Table 86 provides the levelized value for energy DRIPE installed in each state, broken down between the value of price reductions in the state of installation (intrazonal) and in the rest-of-pool (interzonal). Intrazonal and interzonal values may be added to determine the total DRIPE effect.

Table 86. Seasonal energy DRIPE values for measures installed in 2021 (2021 $ per MWh)

Type	Season	Period	CT	MA	ME	NH	RI	VT
Intrazonal	Summer	On-Peak	$2.78	$7.41	$1.93	$2.04	$1.38	$0.35
		Off-Peak	$1.72	$4.56	$1.31	$1.29	$0.82	$0.23
	Winter	On-Peak	$4.34	$11.50	$3.68	$3.44	$1.95	$0.64
		Off-Peak	$3.72	$9.99	$3.26	$3.00	$1.67	$0.55
Interzonal	Summer	On-Peak	$13.23	$8.29	$14.05	$13.89	$14.58	$15.51
		Off-Peak	$8.27	$5.23	$8.66	$8.64	$9.13	$9.67
	Winter	On-Peak	$21.36	$13.71	$21.99	$22.13	$23.66	$24.82
		Off-Peak	$18.61	$11.91	$19.05	$19.21	$20.58	$21.57

Note: Values shown are levelized over 15 years.

9.3. Electric capacity DRIPE

This section describes our methodology and assumptions for capacity market DRIPE effects. If the capacity market were in equilibrium, and all the marginal sources of capacity had similar cost characteristics, reducing demand or adding capacity would not have much effect on capacity price. However, results from recent forward capacity auctions have shown that this is not the case (see discussion in Chapter 5: *Avoided Capacity Costs*). Instead, the marginal sources of capacity vary in price. The bid prices for individual units appear to have declined over time, as well. Hence, the clearing price of capacity continues to be sensitive to the amount of energy efficiency resources cleared in the FCM, and to the effect of uncleared energy efficiency resources on demand.[250] As a result, we can be certain that capacity price effects are both real and material.

AESC estimates two varieties of capacity DRIPE effects:

- Cleared DRIPE benefits, which are benefits of measures that clear in the ISO New England FCM
- Uncleared DRIPE benefits, which are benefits of measures that are not submitted into or otherwise do not clear in the ISO New England FCM

This section describes the methodology used to calculate both types of capacity DRIPE. We begin with a discussion of price shifts, then describe which components of regional demand these price shifts are eligible to be applied, then describe the methodologies for calculating benefits in the two categories of capacity DRIPE.

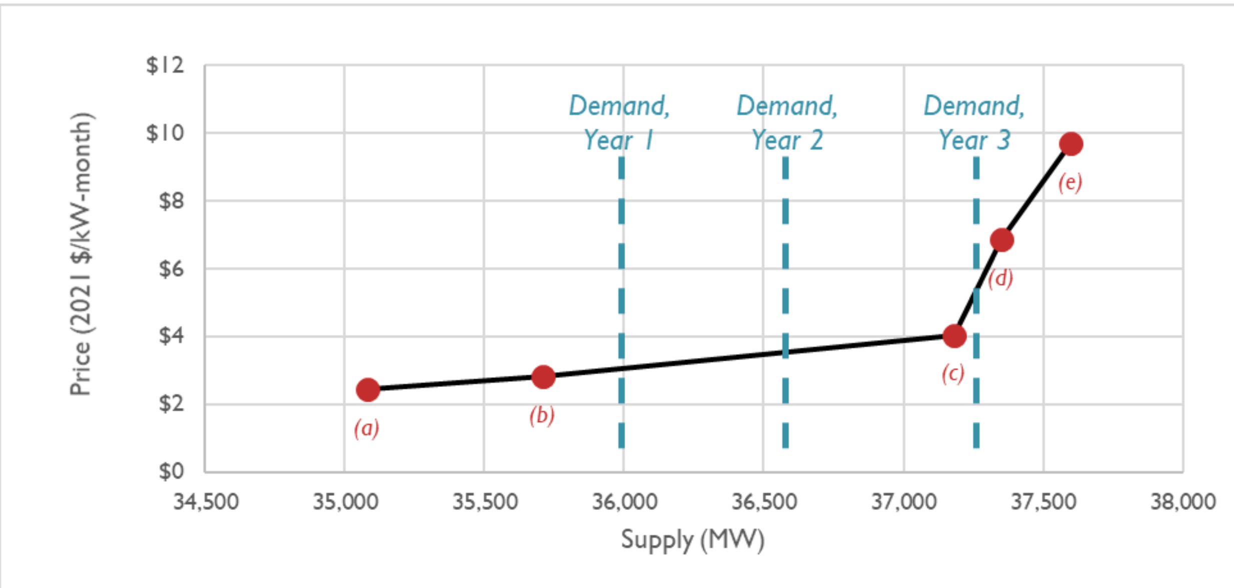
[250] FCM prices will be determined to a large extent by the prices at which existing resources choose to delist. By delisting, existing resources in New England are able to: (1) sell into another market such as New York, (2) shut down, or (3) operate in the energy market without obligations in the capacity market. New resources can defer implementation or operate in the energy market. Resources that do not clear in one FCA can bid into the subsequent auctions, including Annual Reconfiguration Auctions, or sell capacity bilaterally, such as to assume the capacity obligation of a resource that cleared.

Calculating price shifts in the capacity market

The "price shift" of capacity refers to how much the price of capacity (measures in $/kW-year per MW) changes in response to changes in demand. As in past AESC, we estimate price shifts for future years using the slope of the most recent capacity market auction (in the case of AESC 2021, this is FCA 15, conducted in February 2021), shifted to reflect the change in supply capacity that has occurred since that auction.

Figure 49 depicts the five known datapoints for supply and price in FCA 15.[251] The line segment between each one of these points has a slope, which is effectively the price shift used in AESC 2021. Depending on where demand crosses the supply curve, the clearing price will have a different associated price shift. For example, in Figure 49, demand in Year 1 and Year 2 will produce the same price shift. Demand in Year 3, however, crosses at a different line segment and will yield a different price shift. Practically speaking, the shallower the line segment, the lower the price shift's value is. Conversely, steeper line segments produce higher price shifts. See Table 87 for our estimates of the price shifts for each counterfactual.

Figure 49. Supply curve for FCA 15 with illustrative demand lines



Note: Demand lines are illustrative and do not represent actual or projected demand in any year.

[251] ISO New England. Last accessed March 11, 2021. *Forward Capacity market (FCA 15) Result.* Available at https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf

Table 87. Price shifts for capacity DRIPE (2021 $/kW-month per MW) in rest-of-pool region

	FCA	Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
2021	12	$0.00038	$0.00038	$0.00038	$0.00038
2022	13	$0.00033	$0.00033	$0.00033	$0.00033
2023	14	$0.00051	$0.00051	$0.00051	$0.00051
2024	15	$0.00058	$0.00058	$0.00058	$0.00058
2025	16	$0.00058	$0.00058	$0.00058	$0.00058
2026	17	$0.00058	$0.00058	$0.00058	$0.00058
2027	18	$0.00083	$0.00083	$0.00083	$0.00083
2028	19	$0.00083	$0.00083	$0.00083	$0.00083
2029	20	$0.00083	$0.00083	$0.00083	$0.00083
2030	21	$0.00083	$0.00083	$0.00083	$0.00083
2031	22	$0.00083	$0.00083	$0.00083	$0.00083
2032	23	$0.00083	$0.00083	$0.00083	$0.00083
2033	24	$0.00083	$0.00083	$0.00083	$0.00083
2034	25	$0.01657	$0.01657	$0.01657	$0.01657
2035	26	$0.00083	$0.00083	$0.00083	$0.00083

Notes: Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Calculating capacity DRIPE

Price shifts are described in units of dollars-per-kW-month per MW (effectively, price per demand). To allow these numbers to be applied to any generic change in demand (e.g., from an energy efficiency measure), we multiply these values by the projected demand.

We calculate demand using two different sets of numbers. First, using the EnCompass model, we project future demand for each state and the region as a whole given the inputs described in Chapter 4: *Common Electric Assumptions*. Second, we multiply this by the fraction of demand that is unhedged. Unhedged demand is the quantity of electricity that has not already been procured ahead of time, and is thus subject to changes in the capacity market prices.

The unhedged percentage varies by state. Vermont utilities are vertically integrated and own (or have under long-term contract) a large portion of their capacity requirements. The same is also true for municipal utilities. The Connecticut utilities have contracts for differences with a number of generators built to relieve a transmission constraint, and all the restructured states have some legacy contracts and/or small post-restructuring contracts that provide capacity. In general, the long-term purchase of capacity has fallen out of favor, even where the utilities are purchasing energy long term.[252] For Vermont, we estimate hedged demand percentages based on data from the most recently available

[252] In addition, the generation-supply offers by the utilities, municipal aggregators, and third-party marketers provide short-term price certainty for a sizable portion of load. By the time those rates are locked in, the capacity price is generally known. For the small percentage of power-supply contracts for more than three years into the future, the capacity component is generally subject to market adjustment. Hence, retail power-supply contracts have little if any value in hedging capacity price risk.

Green Mountain Power IRP, and we assume hedged demand share in the rest of the state is similar.[253] Specific data on hedged capacity for other states is less available. We rely on capacity contracts as published in FERC Form 1 and we assume half of all remaining vertically integrated demand is hedged as a proxy for the above-mentioned dynamics.

Table 88 describes the resulting unhedged capacity demand assumptions for Counterfactual #1. Values for Counterfactual #2 are lower, given its lower projections of load. Values for Counterfactual #3 and Counterfactual #4 are similar to Counterfactual #1. See the *AESC 2021 User Interface* for detail on all counterfactuals.

Table 88. Unhedged capacity for Counterfactual #1

	ISO	CT	MA	ME	NH	RI
2021	25,091	5,740	12,436	2,057	2,502	1,972
2022	25,797	5,841	12,712	2,108	2,556	2,015
2023	26,280	5,941	12,989	2,110	2,609	2,057
2024	26,458	5,949	13,099	2,132	2,629	2,072
2025	27,305	6,126	13,525	2,211	2,713	2,138
2026	26,877	5,982	13,350	2,183	2,674	2,106
2027	27,514	6,104	13,678	2,245	2,738	2,156
2028	27,988	6,184	13,930	2,294	2,786	2,194
2029	28,517	6,277	14,208	2,347	2,840	2,235
2030	28,967	6,347	14,443	2,401	2,885	2,273
2031	29,427	6,419	14,684	2,457	2,931	2,312
2032	29,832	6,469	14,952	2,486	2,965	2,336
2033	30,452	6,578	15,269	2,557	3,026	2,385
2034	31,004	6,668	15,555	2,624	3,081	2,430
2035	31,575	6,761	15,851	2,693	3,138	2,477

Notes: Data on clearing prices for other counterfactuals can be found in the AESC 2021 User Interface.

Price shifts and unhedged capacity quantities are two of the primary inputs used to estimate capacity DRIPE. The following sections describe the methodologies used to translate these values into (a) cleared capacity benefits and (b) uncleared capacity benefits.

Calculating cleared capacity DRIPE

AESC 2021, like previous AESC studies, utilizes a decay schedule for cleared capacity DRIPE. This schedule describes how these effects phase in and phase out.

First, we assume that all cleared measures have full DRIPE benefits in the first year they are installed. However, we assume that this effect does not last indefinitely. Over time, customers will respond to lower prices by using somewhat more energy, including at the peak. In addition, lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources, which will result in these resources being removed from the supply curve. Further, some new

[253] See *2018 Integrated Resource Plan*. Green Mountain Power. Chapter 8. Figure 8-20.

proposed resources that have not cleared for several auctions may be withdrawn (if, for example, contracts and approvals expire, raising the cost of offering the resource into future auctions).[254] As a result, we assume that the effects of DRIPE fade out over time. Based on expert judgement, we use the same assumption used in prior AESC studies, wherein the phase-out is linear over time, reaching an effect of zero in the seventh year. We assume that measures with shorter lifetimes use the same decay schedule, rather than a compressed decay schedule or some other alternative. This is because the phase-out of DRIPE effects is based on market dynamics, rather than the features of individual measures.

Table 89 shows the decay schedule used for cleared capacity measures installed in 2021. Measures installed in later years have the same decay schedule, but shifted by one or more years.

Table 89. Decay schedule used for cleared capacity for measures installed in 2021

	Decay	1- Decay
2021	0%	100%
2022	17%	83%
2023	33%	67%
2024	50%	50%
2025	67%	33%
2026	83%	17%
2027	100%	0%
2028	100%	0%
2029	100%	0%
2030	100%	0%
2031	100%	0%
2032	100%	0%
2033	100%	0%
2034	100%	0%
2035	100%	0%

After calculating this decay schedule, we calculate cleared capacity DRIPE as using the formulas described in Equation 9 (for interzonal DRIPE) and Equation 10 (for intrazonal). Interzonal DRIPE is calculated by multiplying the price shift for a given year by the unhedged capacity quantity for a given state, by one minus the decay percentage for that year. Meanwhile, intrazonal DRIPE uses the exact same calculation, except replaces the unhedged capacity quantity for the given state with the unhedged capacity quantity for the rest of the region (less the state in question).

Equation 9. Calculation of interzonal (zone-on-zone) cleared capacity DRIPE

$$Capacity\ DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z \\ Period\ P}} = \left[Price\ Shift\ \times Hedged\ Capacity_{\substack{Zone\ Z \\ Period\ P}}\right] \times (1 - Decay)$$

[254] We note, however, that the historical record of (a) retirements and (b) cancelation of planned generation does not show any clear association with falling capacity prices.

Equation 10. Calculation of intrazonal (zone-on-rest-of-pool) cleared capacity DRIPE

$$Capacity\ DRIPE_{\substack{ROP\ |\ Zone\ Z \\ Period\ P}} = \left[Price\ Shift \times \left(Hedged\ Capacity_{\substack{ISO \\ Period\ P}} - Hedged\ Capacity_{\substack{Zone\ Z \\ Period\ P}}\right)\right] \times (1 - Decay)$$

Table 90 shows cleared capacity DRIPE for each region for measures that are installed in 2021.

Table 90. Cleared capacity DRIPE by year for measures installed in 2021 (2021 $ per kW-year)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	$116	$26	$57	$9	$12	$9	$2	$89	$58	$106	$104	$106	$114
2022	$86	$19	$42	$7	$9	$7	$2	$66	$44	$79	$77	$79	$84
2023	$108	$24	$53	$9	$11	$8	$2	$84	$55	$99	$97	$100	$106
2024	$92	$21	$46	$7	$9	$7	$2	$72	$47	$85	$83	$85	$90
2025	$63	$14	$31	$5	$6	$5	$1	$49	$32	$58	$57	$58	$62
2026	$32	$7	$16	$3	$3	$3	$1	$25	$16	$29	$29	$29	$31
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2033	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15-year levelized	**$34**	**$8**	**$17**	**$3**	**$3**	**$3**	**$1**	**$27**	**$17**	**$32**	**$31**	**$32**	**$34**

Calculating uncleared capacity DRIPE

Demand-response and load-management programs that do not clear in the FCM also generate capacity DRIPE benefits, albeit with different timing and of different magnitudes. Capacity DRIPE for uncleared resources is calculated analogously to that of cleared resources, but the decay schedule and market clearing prices are adjusted to reflect different market features.

To calculate uncleared capacity DRIPE, we utilize a modified version of the same phase-in / phase-out schedule described above in Section 5.2: *Uncleared capacity calculations*. As with uncleared capacity, we assume that uncleared capacity DRIPE effects do not appear until five years after a measure is installed, and that they persist at various magnitudes and lengths of time depending on the measure's lifetime. However, uncleared capacity DRIPE differs in that we also assume that DRIPE effects decay over time, following the same decay schedule described in Table 89.

As with uncleared capacity, the calculations of uncleared capacity DRIPE also utilize estimates of reserved margin and scaling factors (also described above in Section 5.2: *Uncleared capacity calculations*).

To estimate uncleared capacity DRIPE, we use the following calculations:

- For intrazonal (zone-on-zone) uncleared capacity DRIPE in a particular state and year, we calculate the product of (a) the state's unhedged demand, (b) the price shift for that year, (c) the effect-and-decay schedule that matches the measure's lifetime, and (d) the scaling factor, if relevant. Unlike cleared capacity DRIPE, this value is then multiplied by one plus the reserve margin to reflect the fact that since the measure is uncleared, it is capable of avoiding some reserve margin.[255]
- For interzonal (zone-on-rest-of-pool) uncleared capacity DRIPE for a particular state and year, we calculate the product of (a) regional unhedged demand minus the state's unhedged demand, (b) the price shift for that year, (c) the effect-and-decay schedule that matches the measure's lifetime, and (d) the scaling factor, if relevant. This value is then multiplied by one plus the reserve margin.

Table 90 shows uncleared capacity DRIPE for each region for measures that are installed in 2021, assuming a measure life of 10 years. Here, we observe uncleared capacity DRIPE benefits that are higher than cleared capacity DRIPE benefits primarily because this particular example describes avoided costs for a measure with a 10-year life. Measures with this program lifetime provide substantial uncleared DRIPE benefits in the mid-2020s and early 2030s, but do not provide cleared capacity DRIPE benefits in those same years.

[255] As the measure is uncleared, it is effectively "counted" in the demand side of the capacity auction (i.e., within the load forecast). In contrast, measures that are cleared are effectively treated the same as conventional power plants (i.e., supply), and through the auction effectively require the purchase of some extra amount of capacity to act as a reserve margin.

Table 91. Uncleared capacity DRIPE by year for measures installed in 2021 (2021 $ per kW-year)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2026	$64	$14	$32	$5	$6	$5	$1	$49	$32	$58	$57	$59	$62
2027	$140	$31	$70	$11	$14	$11	$3	$109	$71	$129	$126	$129	$137
2028	$181	$40	$90	$15	$18	$14	$4	$141	$91	$166	$163	$167	$177
2029	$211	$47	$105	$17	$21	$17	$5	$165	$106	$194	$190	$195	$207
2030	$198	$43	$99	$16	$20	$16	$4	$155	$99	$182	$178	$182	$194
2031	$146	$32	$73	$12	$15	$11	$3	$114	$73	$134	$131	$134	$143
2032	$91	$20	$46	$8	$9	$7	$2	$71	$45	$83	$82	$84	$89
2033	$52	$11	$26	$4	$5	$4	$1	$41	$26	$48	$47	$48	$51
2034	$471	$101	$236	$40	$47	$37	$10	$370	$235	$431	$424	$434	$461
2035	$6	$1	$3	$1	$1	$0	$0	$5	$3	$6	$6	$6	$6
15-year levelized	**$102**	**$22**	**$51**	**$8**	**$10**	**$8**	**$2**	**$79**	**$51**	**$93**	**$92**	**$94**	**$100**

Note: This chart assumes a measure life of 10 years. Measures with other measure lives will have completely different uncleared capacity DRIPE effects. See the AESC 2021 User Interface for more information.

Important caveats for applying uncleared capacity DRIPE values

Uncleared capacity DRIPE is different than many other avoided cost categories. Because uncleared capacity DRIPE describes an effect that fades out over time due to the market's responses to that effect, users should sum avoided costs over the entire study period, regardless of any one measure's lifetime. For example, the avoided costs of a 1 MW measured installed in 2021 would be equal to the sum of the values from 2021 through 2055, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[256]

Uncleared resources affect the load forecast only to the degree that these resources provide load reductions on the hours used in the load forecast regression. Some resources—such as demand response resources—may be active only on one or some of the hours used in the load forecast. As a result, these resources would provide a diminished uncleared capacity benefit. We recommend that program administrators apply a scaling factor to the benefits detailed in Table 91 to account for this effect. See Appendix K: *Scaling Factor for Uncleared Resources* for more information on how this scaling factor is calculated and how it can be applied.

[256] We note that this is the same approach used for summing avoided costs for uncleared capacity and uncleared capacity DRIPE, but no other avoided cost categories.

9.4. Natural gas DRIPE

Just as reducing electric load reduces electric energy prices, reducing natural gas usage reduces demand for natural gas in producing regions and therefore reduces the market price of that natural gas supply. This natural gas price reduction effect is natural gas DRIPE. The price for natural gas—and associated benefits—can be broken into two components:

1. The supply component, determined by North American demand and supply conditions on a largely annual basis.
2. Transportation costs or "basis," determined by contract prices for LDCs and by the balance of regional demand and supply (mostly from pipelines) on a daily and seasonal basis for other users, especially electric generators.

Importantly, only the supply component of natural gas DRIPE is used in cost-effectiveness screening of gas measures. This is because LDCs and most other suppliers of gas to the end-use rely primarily on firm long-term contracts for pipeline and storage capacity to allow for delivery of natural gas. As a result, the basis DRIPE effect benefits only electric customers.

Natural gas supply DRIPE

This section focuses on the calculation of natural gas supply DRIPE. This is the DRIPE effect that is applied to end-use measures that produce natural gas savings.

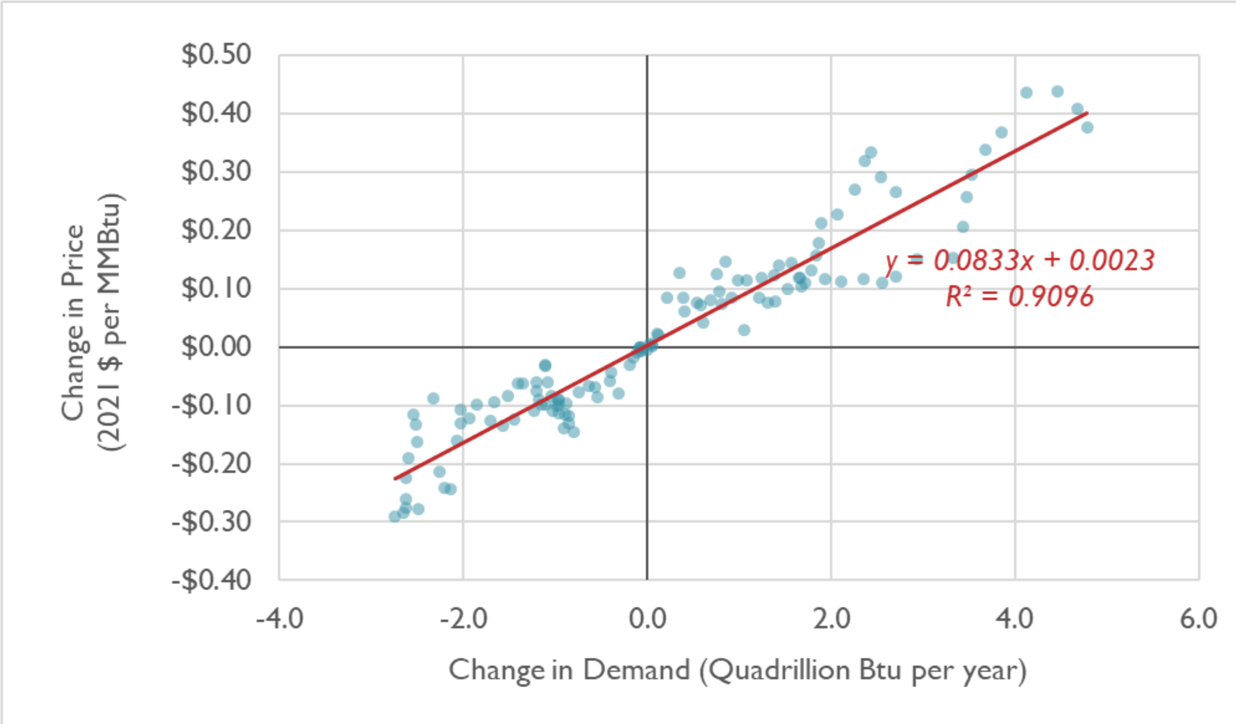
Calculating elasticities

Elasticity describes how prices of a commodity respond to changes in demand. In AESC 2018, we relied on a literature review of recent estimates of natural gas elasticities (including both top-down and bottom-up empirical estimates). For AESC 2021, we instead rely on a calculation of the implied response of natural gas prices to supply changes observed in different scenarios modeled in EIA's AEO 2021.

Figure 50 compares annual data points from AEO 2021. Each data point represents the difference in both prices and demand for one AEO side scenario relative to the price and demand for natural gas in AEO 2021 Reference case for the same year. This figure includes datapoints from four different AEO side scenarios: the High economic growth, Low economic growth, High renewable cost, and Low renewable cost cases. This analysis encompasses all years from 2020 through 2050. A linear regression of this dataset provides a slope that indicates how changes in price are related to changes in demand.

Overall, we find that reducing demand by one quadrillion Btu reduces EIA's estimate of the market price by \$0.083 per MMBtu in 2021 dollars. This is about half of the AESC 2018 value of \$0.16/MMBtu per quadrillion Btu/year (in 2021 dollars).

Figure 50. Effect of changing gas demand on gas price



Note: Deltas compare annual prices and demand in four AEO 2021 scenarios versus the AEO 2021 Reference case.

Calculating natural gas supply DRIPE

As with electricity DRIPE effects, the price reduction per MMBtu saved is a very small portion of the price per MMBtu, but each MMBtu saved reduced prices for a very large number of MMBtus. According to AEO 2021, each year, New England is expected to consume 0.5 quadrillion Btu for non-electric uses.[257] Multiplying this quantity by the price shift ($0.083/MMBtu per quadrillion Btu) yields a natural gas supply DRIPE effect of $0.05 per MMBtu. The quantity of gas consumed for non-electric uses changes over time, and among states. Between 2021 and 2035, AEO 2021 estimates that non-electric gas demand will increase by about 16 percent. Demand in each state is projected based on recent historical observations from 2014 through 2018. Vermont, for example, is projected to consume about 0.01 quadrillion Btu while Massachusetts is projected to consume about 0.3 quadrillion Btu. These differences yield different DRIPE effects for each state.

We do not expect any decay in gas DRIPE; benefits should continue as long as the efficiency measure continues to reduce load. In contrast to intra-month price variation driving the electric energy DRIPE, the studies and AEO gas-price forecasts reflect the full long-term costs of gas development (at least after the first few years), not just the operation of existing wells. In addition, gas supply DRIPE is measuring

[257] Gas supply DRIPE is applied to gas efficiency measures which displace consumption of gas that has been purchased by LDCs. As a result, we use non-electric consumption for this calculation.

the effect of demand on the marginal cost of extraction for a finite resource. If anything, lower gas usage in 2021 will leave more low-cost gas in the ground to meet demand in 2022, causing the DRIPE effect to accumulate over time.

However, we do assume that only a portion of consumption is responsive to DRIPE as a result of short-term contracts for gas. In Year 1, we assume that half of all gas demand is tied up in short-term contacts and is thus not impacted by DRIPE effects. This decreases to 20 percent in Year 2 and is assumed to fade away entirely in Year 3. Table 92 describes this impact schedule for measures that are installed in 2021. Measures installed in subsequent years would see these values shifted by one or more years. This is the same assumption used for short-term energy contracts for energy DRIPE (see Section 9.2: *Electric energy DRIPE*).

Table 92. Share of demand that is responsive to natural gas supply DRIPE

Year	Share of demand not impacted by DRIPE	Share of demand impacted by DRIPE
2021	50%	50%
2022	20%	80%
2023	0%	100%
…	…	…
2035 and later	0%	100%

Note: Values shown are for measures installed in 2021. Measures installed in 2022 would see these effects shifted by one year, measures installed in 2023 would see these effects shifted by two years, and so on.

Natural gas supply DRIPE values

Table 93 depicts the value of demand reduction for each state. This is calculated by obtaining the product of (a) the price shift (in 2021 $/MMBtu per quadrillion Btu), (b) the state's non-electric natural gas consumption, and (c) the share of demand that is responsive to natural gas supply effects.[258] Table 93 also shows the DRIPE effects for each state on the rest of the region. These values are calculated by subtracting the own-state value from the New England total in each year.

Using this table, we can see estimate the benefit for a reduction in gas use in each year. For example, a 1 MMBtu reduction in natural gas demand in 2023 yields a gas supply DRIPE benefit of $0.045 for New England as a whole.

AESC 2021's gas supply DRIPE estimates are lower than those found in AESC 2018, mostly due to lower price shift ($0.083/MMBtu per quadrillion Btu, down from $0.158/MMBtu per quadrillion Btu). Other changes are due to differences in historical gas consumption and projected gas consumption across the six states.

[258] Note that this consumption (and everything related to natural gas supply DRIPE) is independent of the natural gas price and avoided cost forecasts developed in Chapter 0:

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Table 93. Natural gas supply DRIPE benefit (2021 $ per MMBtu)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.020	0.005	0.011	0.001	0.001	0.002	0.000	0.015	0.009	0.019	0.019	0.019	0.020
2022	0.036	0.009	0.019	0.002	0.002	0.003	0.001	0.027	0.016	0.033	0.034	0.033	0.035
2023	0.045	0.011	0.024	0.003	0.002	0.003	0.001	0.034	0.021	0.042	0.043	0.042	0.044
2024	0.046	0.011	0.025	0.003	0.002	0.003	0.001	0.034	0.021	0.043	0.043	0.042	0.045
2025	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2026	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2027	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2028	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2029	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.043	0.045
2030	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.043	0.045
2031	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.045
2032	0.047	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.045
2033	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.046
2034	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.046
2035	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.022	0.044	0.045	0.043	0.046
10-year levelized	**0.044**	**0.011**	**0.024**	**0.003**	**0.002**	**0.003**	**0.001**	**0.033**	**0.020**	**0.041**	**0.041**	**0.040**	**0.043**

Note: Values differ across states because states vary in terms of size of non-electric gas consumption.

Natural gas basis DRIPE

Reductions in annual gas use will not only reduce the supply cost of natural gas, but also the basis. The basis is the price differential between the wholesale market price of gas in New England and the prices in the supply areas (sometimes called the "transportation" cost of natural gas). Since LDCs and most other suppliers of gas to the end-use rely primarily on firm long-term contracts for pipeline and storage capacity to allow for delivery of natural gas, the basis DRIPE effect benefits only electric customers and is thus only used in G-E cross-DRIPE and below in E-G-E cross-DRIPE (see more below in Section 9.5: *Cross-fuel market price effects*).

Calculating elasticities

The majority of the price differential for natural gas in New England is attributable to constraints on gas delivery capacity into New England from the Mid-Atlantic region. As a result, our analysis focuses on the basis between the Texas Eastern Transmission Zone M-3 (in Pennsylvania and New Jersey) and the Algonquin Gas Transmission citygates in Connecticut, Rhode Island, and eastern Massachusetts.[259]

[259] To be clear, this calculation of DRIPE ignores effects from gas delivered to New England directly from Canada or from LNG.

Using data spanning three winters (December 2017 through March 2020), we examine prices and demand for gas to determine price shifts over different periods of time. First, we utilize daily natural gas delivery data for the Algonquin Pipeline and Tennessee Gas Pipeline to determine the total amount of gas delivered to New England from the south.[260] For each day, we calculate the aggregate surplus capacity for these two pipelines. Separately, we also estimate the price paid for gas flowing each day at both the TETCO M3 Hub and the Algonquin Citygate.[261] The difference between these two values is the assumed basis for natural gas in New England.

Next, we assess a set of regressions of this surplus and basis data to determine what the price shift is at different times of the year. The slope of a linear regression describes the price shift. Table 94 describes the time periods and estimated price shifts. Note the use of two different "winter" periods and two different "summer" periods—one for electricity and one for gas. The seasonal assignments for the electric seasons are based on ISO New England's definition, while the gas seasons are consistent with the analysis in Chapter 0:

[260] Spectra Energy. Last accessed March 11, 2021. "Algonquin Gas Transmission." *Spectraenergy.com*. Available at https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG.

Tennessee Gas Pipeline Company. Last accessed March 11, 2021. "Informational Postings: Point Capacity." *Kindermorgan.com*. Available at https://pipeline2.kindermorgan.com/Capacity/OpAvailPoint.aspx?code=TGP.

[261] Natural Gas Intelligence. Last accessed March 11, 2021. "Texas Eastern M-3, Delivery Daily natural Gas Price Snapshot." *Naturalgasintel.com*. Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/NEATETM3DEL/.

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Table 94. Gas basis price shifts by season

Season	Months included	Basis price shift (2021 $/MMBtu per BBtu/day)
Summer, electric	June through September	$0.00035
Winter, electric	October through May	$0.00203
Summer, gas	April through October	$0.00132
Winter, gas	November through March	$0.00328
Annual	**All months**	**$0.00180**

Over time, we assume that these basis price shifts decay as a result of a rebound effect (e.g., consumers using more gas given that it is cheaper), response of existing generation to price changes (i.e., gas units stay online longer and generate more electricity because of lower gas prices), and response of new generation to price changes (i.e., as prices remain low, there is less pressure to switch to newer, more efficient gas units). The combined effect of these drivers results in the decay schedule described in Table 95. Note that this schedule is for measures installed in 2021; measures installed in later years (e.g., 2021, 2022, and so on) use this same decay schedule but shifted by one year.

Table 95. Percent of gas basis decayed by year for measures installed in 2021

	Gas Basis Decay (%)
2021	1.3%
2022	4.1%
2023	6.8%
2024	16.3%
2025	25.4%
2026	46.8%
2027	67.0%
2028	76.0%
2029	84.5%
2030	92.5%
2031	100.0%
2032	100.0%
2033	100.0%
2034	100.0%
2035	100.0%

We then apply these decay percentages to the price shifts described above. Table 96 shows the decayed basis values for a measure installed in 2021, with the supply gas DRIPE values (which are not decayed) for comparison. All values have been converted in to $/MMBtu per Quadrillion Btu terms, as these are otherwise very small numbers.

Table 96. Decayed natural gas DRIPE values (2021 $/MMBtu per Quadrillion Btu reduced)

	Basis					Supply
	Electricity Summer	*Electricity Winter*	*Gas Summer*	*Gas Winter*	Annual	*Annual*
2021	0.0028	0.0083	0.0061	0.0214	0.0049	0.0001
2022	0.0028	0.0080	0.0059	0.0208	0.0047	0.0001
2023	0.0027	0.0078	0.0058	0.0202	0.0046	0.0001
2024	0.0024	0.0070	0.0052	0.0182	0.0041	0.0001
2025	0.0021	0.0062	0.0046	0.0162	0.0037	0.0001
2026	0.0015	0.0045	0.0033	0.0116	0.0026	0.0001
2027	0.0009	0.0028	0.0020	0.0072	0.0016	0.0001
2028	0.0007	0.0020	0.0015	0.0052	0.0012	0.0001
2029	0.0004	0.0013	0.0010	0.0034	0.0008	0.0001
2030	0.0002	0.0006	0.0005	0.0016	0.0004	0.0001
2031	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2032	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2033	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2034	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2035	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001

In New England, basis benefits are significantly larger than supply benefits, for two reasons. First, New England demand is only a small portion of North American demand, so a percentage change in regional load has a much smaller percentage effect on continent-wide demand. Second, while gas producers can increase production from year to year, pipeline constraints are much less flexible, requiring years of planning, siting, permitting and most importantly contracting.

Basis price shifts are not outright applied to any measures. Instead, they are combined with several other factors and used to calculate cross-DRIPE. See "G-E cross-DRIPE" and "E-G-E cross-DRIPE" subsections below in Section 9.5: *Cross-fuel market price effects*. See these subsections for comparisons of AESC 2021 values with analogous values from AESC 2018.

9.5. Cross-fuel market price effects

The preceding sections calculated direct DRIPE effects where a reduction in demand for a given commodity reduced prices for that same commodity. DRIPE benefits also accrue indirectly through cross-DRIPE, which measures the impact that a reduction in one commodity has on a different commodity. We assess three kinds of cross-DRIPE:

1. **Gas-to-electric (G-E) cross-DRIPE ($/MWh)** measures the benefits to electricity consumers that result from a reduction in gas demand. Gas-fired generators set electric market prices in most hours, so reducing gas prices should reduce electricity prices.

2. **Electric-to-gas (E-G) cross-DRIPE ($/MMBtu)** measures the benefits to gas consumers from a reduction in electricity demand. Electric power accounts for about one-third of the region's gas demand, so reducing electricity demand should reduce gas prices.
3. **Electric-to-gas-to-electric (E-G-E) cross-DRIPE ($/MWh)** combines the first two benefits. Reductions in electricity demand should reduce gas prices (E-G cross-DRIPE) which should, in turn reduce electricity prices (G-E cross-DRIPE). E-G-E cross-DRIPE is separate from direct electric energy DRIPE and does not double-count any benefits. Reductions in electricity demand yield two benefits. First, lower demand levels will tend to switch the marginal unit to something lower cost, yielding a market price reduction through plant substitution. Second, lower electricity demand levels reduce the demand for, and price of, natural gas. Thus, natural gas power plants, which set prices in most hours, burn less expensive gas than they would have otherwise. Electric energy DRIPE captures the first benefit, while E-G-E cross-DRIPE captures the second benefit. In our energy DRIPE calculations, we explicitly control for natural gas prices, which means own-fuel energy DRIPE is only measuring the benefits of switching from a less efficient plant to a more efficient plant. For E-G-E DRIPE, we hold the powerplant constant, and reflect how a change in gas prices changes electric prices.

Electric-to-gas (E-G) cross-DRIPE

Electric-to-Gas (E-G) cross-DRIPE measures the benefits to gas consumers from a reduction in electricity demand. Electric power accounts for approximately one-third of the region's gas demand, so reducing electricity demand should reduce gas prices, all else equal.

To calculate E-G cross-DRIPE, we utilize the supply gas price shift calculated in Section 9.4: *Natural gas DRIPE*: $0.083/MMBtu per quadrillion Btu. Next, we convert this price shift's units into $-per-MWh per quadrillion Btu so that it may be applied to MWh savings. We do this by relying on data about the marginal heat rate for emitting plants as reported by ISO New England.[262] According to this data, the marginal emitting plant heat rate is 7.74 MMBtu per MWh.[263] If we scale this to reflect the amount of time gas is expected to be on the margin in the energy market, we estimate a marginal gas heat rate of 6.43 MMBtu per MWh.[264] This value can then be multiplied by the price shift to produce an estimate of $0.54/MWh per quadrillion Btu (see Equation 11).

[262] ISO New England. May 2020. *Electric Generator Air Emissions Report.* Available at https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf.

[263] Id, Section 5.3.2.2.

[264] According to ISO New England, from 2014 to 2018, natural gas plants and pumped storage plants (which are generally powered by marginal units) were marginal 83 percent of the time (see 2018 Air Emissions Report, Figure 4-7).

Equation 11. Price shift in dollar-per-MWh terms

$$Dollar\ per\ MWh\ price\ shift = dollar\ per\ MMBtu\ price\ shift \times marginal\ gas\ heat\ rate$$

$$= \frac{\frac{\$0.083}{MMBtu}}{Quadrillion\ Btu} \times \frac{6.43\ MMBtu}{MWh} = \frac{\frac{\$0.54}{MWh}}{Quadrillion\ Btu}$$

To determine E-G DRIPE, we then follow the same overall process used to estimate natural gas supply DRIPE. For each year and state, we calculate the product of (a) estimated natural gas consumption, (b) the estimated share of consumption that is DRIPE-responsive (see Table 92), and (c) the price shift.

Table 97. Electric-to-gas (E-G) cross-DRIPE benefit (2021 $ per MWh)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.129	0.032	0.070	0.008	0.006	0.010	0.003	0.097	0.059	0.121	0.123	0.119	0.126
2022	0.229	0.057	0.124	0.014	0.011	0.018	0.005	0.173	0.105	0.215	0.218	0.212	0.224
2023	0.291	0.072	0.157	0.018	0.015	0.022	0.007	0.219	0.133	0.273	0.276	0.268	0.284
2024	0.293	0.072	0.158	0.018	0.015	0.022	0.007	0.221	0.135	0.275	0.278	0.271	0.286
2025	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.276	0.280	0.272	0.288
2026	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.277	0.280	0.272	0.288
2027	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.277	0.280	0.272	0.288
2028	0.296	0.073	0.160	0.018	0.015	0.023	0.007	0.222	0.136	0.277	0.281	0.273	0.289
2029	0.296	0.073	0.160	0.018	0.015	0.023	0.007	0.223	0.136	0.278	0.281	0.274	0.289
2030	0.297	0.073	0.161	0.018	0.015	0.023	0.007	0.224	0.137	0.279	0.282	0.275	0.290
2031	0.298	0.074	0.161	0.018	0.015	0.023	0.007	0.224	0.137	0.280	0.283	0.275	0.291
2032	0.299	0.074	0.162	0.019	0.015	0.023	0.007	0.225	0.137	0.280	0.284	0.276	0.292
2033	0.300	0.074	0.162	0.019	0.015	0.023	0.007	0.225	0.138	0.281	0.284	0.277	0.292
2034	0.300	0.074	0.162	0.019	0.015	0.023	0.007	0.226	0.138	0.282	0.285	0.277	0.293
2035	0.301	0.074	0.163	0.019	0.015	0.023	0.007	0.227	0.138	0.283	0.286	0.278	0.294
15-year levelized	**0.280**	**0.069**	**0.151**	**0.017**	**0.014**	**0.021**	**0.007**	**0.211**	**0.129**	**0.263**	**0.266**	**0.259**	**0.273**

Note: Values differ across states because states vary in terms of size of non-electric gas consumption.

Using this table, we can see estimate the benefit for a reduction in gas use in each year. For example, a 1 MWh reduction in electricity demand in 2023 yields an E-G cross-DRIPE benefit of $0.291 for New England as a whole. As with other DRIPE categories, zone-on-rest-of-region DRIPE benefits for each year are calculated for each state by subtracting the own-zone value for a given state from the New England-wide value.

As with gas supply DRIPE, AESC 2021's gas supply DRIPE estimates are lower than those found in AESC 2018, mostly due to lower price shift ($0.083/MMBtu per quadrillion Btu, down from $0.158/MMBtu per quadrillion Btu). Other changes are due to differences in historical gas consumption and projected gas consumption across the six states.

Gas-to-electric (G-E) cross-DRIPE

Just as reductions in electricity demand can produce benefits to gas consumers, so too can reductions in gas demand benefit electric customers. Because this effect changes seasonally, we provide separate DRIPE benefits for annual and winter periods. Annual DRIPE benefits may be best applied to measures that provide savings throughout the year (such as hot water heating efficiency measures) while winter benefits may be best applied to measures that provide savings during the winter only (such as space heating efficiency measures).

To calculate G-E cross-DRIPE values, we first begin with the total price shifts described in Table 96. To calculate the price shift for each season, we add the supply price shift (which does not vary by season) to the basis price shift (which does vary by season). Because the gas basis price shift decays but the gas supply price shift does not, by 2031, the "total" price shift for any seasons is equal to the supply price shift component.

Next, these values undergo a unit conversion. We multiply these price shifts (measured in dollar-per-MMBtu per quadrillion Btu) by the heat rate derived above in the E-G cross-DRIPE section (which is measured in MMBtu per MWh). This translation yields price shifts in dollar-per-MWh per MMBtu.

These price shifts are multiplied by each state's unhedged energy to estimate total DRIPE benefits. For each state, the "energy" is the quantity of electricity demand (in MWh) in the state in question, consumed during the relevant period (e.g., winter, gas), under a particular counterfactual. This total quantity of energy is scaled by the portion of energy that is assumed to be unhedged in each state (i.e., the portion of energy purchases not expected to be subject to the spot market). This unhedged assumption is the same used in energy DRIPE, described above in Table 83. Because system load changes across counterfactuals, the unhedged percentage also changes.

Table 98 summarizes the resulting G-E cross-DRIPE values. For annual effects, we utilize the annual price shift; for winter effects, we rely on gas winter period price shifts.

Table 98. Gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MMBtu) for Counterfactual #1

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Annual (e.g., water heating)	2021	1.45	0.24	0.73	0.17	0.16	0.11	0.03	1.21	0.72	1.28	1.29	1.34	1.42
	2022	2.19	0.36	1.09	0.26	0.25	0.17	0.05	1.82	1.10	1.92	1.94	2.01	2.14
	2023	2.52	0.44	1.19	0.32	0.30	0.21	0.06	2.08	1.33	2.20	2.22	2.31	2.46
	2024	2.03	0.35	0.93	0.28	0.27	0.16	0.05	1.68	1.10	1.76	1.76	1.88	1.98
	2025	1.68	0.24	0.77	0.24	0.24	0.13	0.04	1.43	0.90	1.44	1.43	1.54	1.63
	2026	1.16	0.17	0.51	0.17	0.17	0.10	0.03	0.98	0.64	0.99	0.99	1.06	1.13
	2027	0.73	0.12	0.32	0.11	0.11	0.06	0.02	0.61	0.41	0.62	0.62	0.67	0.71
	2028	0.52	0.09	0.23	0.08	0.07	0.04	0.01	0.43	0.29	0.44	0.45	0.48	0.51
	2029	0.32	0.06	0.14	0.05	0.05	0.03	0.01	0.27	0.18	0.27	0.28	0.30	0.31
	2030	0.15	0.03	0.06	0.02	0.02	0.01	0.00	0.12	0.09	0.13	0.13	0.14	0.15
	2031	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.01	0.02	0.02	0.02	0.02
	2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Winter (e.g., space heating)	2021	2.66	0.44	1.33	0.32	0.30	0.20	0.06	2.21	1.32	2.34	2.36	2.46	2.59
	2022	4.00	0.67	1.99	0.49	0.46	0.31	0.09	3.33	2.01	3.52	3.54	3.70	3.91
	2023	4.61	0.81	2.18	0.59	0.56	0.37	0.11	3.80	2.43	4.02	4.05	4.24	4.50
	2024	3.72	0.64	1.70	0.51	0.50	0.28	0.10	3.08	2.02	3.21	3.22	3.44	3.62
	2025	3.06	0.45	1.41	0.44	0.44	0.23	0.08	2.61	1.65	2.62	2.62	2.83	2.98
	2026	2.10	0.32	0.93	0.31	0.31	0.17	0.06	1.78	1.17	1.79	1.79	1.94	2.04
	2027	1.30	0.21	0.57	0.19	0.19	0.10	0.03	1.09	0.73	1.11	1.11	1.20	1.27
	2028	0.92	0.16	0.40	0.13	0.13	0.07	0.02	0.76	0.52	0.78	0.78	0.85	0.89
	2029	0.55	0.10	0.24	0.08	0.08	0.04	0.01	0.46	0.31	0.47	0.47	0.51	0.54
	2030	0.24	0.05	0.10	0.03	0.03	0.02	0.01	0.19	0.14	0.20	0.21	0.22	0.23
	2031	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
	2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

This table indicates that the annual New England-wide value of G-E cross-DRIPE for 2021 is $1.45 per MMBtu. The winter value ($2.66 per MMBtu) is nearly twice as large because of the higher basis values in the winter months. Importantly, since electricity generation everywhere in New England serves electricity demand throughout New England, the cross-price effect on electric consumers in a given state is not dependent on the amount of gas burned for electric generation in that same state. For each state and year, the zone-on-Rest-of-Pool benefit equals the difference between the ISO-wide benefit and the zonal benefit.

Table 99 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2018 and AESC 2021. As with other DRIPE categories relying on the price shift of natural gas supply, avoided costs for this category are lower in AESC 2021, compared to AESC 2018. This is primarily due to the reduced natural gas supply price shift, but it is also due to differences in projected loads and gas bases price shifts.

Table 99. Comparison of levelized gas-to-electric (G-E) cross-DRIPE benefits (2021 $ per MMBtu)

	ISO NE	CT	MA	ME	NH	RI	VT
Annual							
AESC 2018	2.73	0.58	1.33	0.27	0.29	0.20	0.06
AESC 2021	1.29	0.21	0.61	0.17	0.17	0.10	0.03
Difference ($)	-1.44	-0.37	-0.73	-0.10	-0.12	-0.10	-0.03
Difference (%)	-53%	-64%	-54%	-38%	-42%	-48%	-47%
Winter							
AESC 2018	5.03	1.07	2.45	0.50	0.53	0.36	0.11
AESC 2021	2.34	0.39	1.10	0.31	0.30	0.18	0.06
Difference ($)	-2.68	-0.68	-1.35	-0.19	-0.22	-0.18	-0.05
Difference (%)	-53%	-64%	-55%	-38%	-42%	-50%	-45%

Note: All values are levelized over 10 years.

Electric-to-gas-to-electric (E-G-E) cross-DRIPE

A reduction in electricity prices will reduce the price of natural gas; this reduction in natural gas prices will, in turn, reduce the price of electric energy. The magnitude of this reduction depends both on supply and on basis. E-G-E cross-DRIPE is separate from and offers benefits in addition to electric energy DRIPE.

To calculate E-G-E cross DRIPE, we begin with the price shifts described above in Table 96. As with G-E cross-DRIPE, to calculate the price shift for each season, we add the supply price shift (which does not vary by season) to the basis price shift (which does vary by season). Because the gas basis price shift decays but the gas supply price shift does not, by 2031, the "total" price shift for is simply equal to the supply price shift component.

Next, these values undergo a unit conversion. Just as with G-E cross-DRIPE, we multiply these price shifts (measured in dollar-per-MMBtu per quadrillion Btu) by the heat rate derived above in the E-G cross-DRIPE section (which is measured in MMBtu per MWh). However, for this DRIPE category, we multiply this heat rate by the price shift <u>twice</u>. This translation yields price shifts in dollar-per-MWh per MWh (rather than dollar-per-MWh per MMBtu, as with G-E cross-DRIPE).

As with G-E cross-DRIPE, these price shifts are then multiplied by each state's unhedged energy to estimate total DRIPE benefits. For each state, the "energy" is the quantity of electricity demand (in MWh) in the state in question, consumed during the relevant period (e.g., winter, electric), under a particular counterfactual. This total quantity of energy is scaled by the portion of energy that is assumed to be unhedged in each state (i.e., the portion of energy purchases not expected to be subject to the spot market). As with G-E cross-DRIPE, this unhedged assumption is the same used in energy DRIPE, described above in Table 83.

Table 100 summarizes the E-G-E values for the annual period: these are the values that appear in the *AESC 2021 User Interface* and are applied by program administrators using Appendix B. Table 98 summarizes the summer and winter effects for historical comparison with AESC 2018. These values are not used in cost-effectiveness testing (except to the degree that the seasonal price shifts inform the annual price shift).

Table 100. Annual electric-to-gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MWh)

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Annual	2021	9.32	1.55	4.68	1.11	1.04	0.73	0.21	7.77	4.63	8.21	8.27	8.59	9.11
	2022	14.05	2.34	6.99	1.69	1.60	1.12	0.31	11.71	7.06	12.36	12.44	12.93	13.74
	2023	16.19	2.81	7.67	2.05	1.94	1.35	0.37	13.37	8.52	14.14	14.25	14.83	15.82
	2024	13.07	2.25	5.97	1.78	1.73	1.01	0.32	10.82	7.10	11.29	11.33	12.06	12.74
	2025	10.77	1.56	4.98	1.54	1.55	0.86	0.28	9.21	5.80	9.23	9.22	9.92	10.49
	2026	7.45	1.12	3.31	1.10	1.10	0.61	0.20	6.32	4.14	6.34	6.35	6.84	7.25
	2027	4.68	0.77	2.06	0.68	0.68	0.38	0.12	3.92	2.63	4.00	4.00	4.31	4.56
	2028	3.34	0.57	1.46	0.48	0.48	0.27	0.08	2.77	1.88	2.86	2.86	3.07	3.26
	2029	2.06	0.36	0.90	0.30	0.29	0.17	0.05	1.71	1.16	1.77	1.77	1.90	2.01
	2030	0.96	0.19	0.41	0.14	0.13	0.08	0.02	0.78	0.55	0.83	0.83	0.89	0.94
	2031	0.13	0.03	0.05	0.02	0.02	0.01	0.00	0.10	0.08	0.12	0.12	0.12	0.13
	2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 101. Seasonal electric-to-gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MWh)

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Electric Summer	2021	1.96	0.33	0.99	0.22	0.21	0.16	0.04	1.63	0.97	1.74	1.74	1.80	1.92
	2022	2.95	0.50	1.48	0.33	0.33	0.25	0.06	2.45	1.47	2.62	2.62	2.70	2.89
	2023	3.40	0.60	1.62	0.41	0.40	0.30	0.07	2.80	1.78	3.00	3.01	3.10	3.33
	2024	2.74	0.48	1.27	0.35	0.36	0.22	0.06	2.26	1.48	2.39	2.39	2.52	2.68
	2025	2.26	0.34	1.06	0.31	0.32	0.19	0.06	1.93	1.21	1.96	1.95	2.07	2.21
	2026	1.57	0.24	0.71	0.22	0.23	0.14	0.04	1.33	0.87	1.35	1.35	1.44	1.53
	2027	1.00	0.17	0.44	0.14	0.14	0.09	0.02	0.83	0.56	0.86	0.86	0.92	0.98
	2028	0.72	0.13	0.32	0.10	0.10	0.06	0.02	0.60	0.40	0.62	0.62	0.66	0.71
	2029	0.46	0.08	0.20	0.06	0.06	0.04	0.01	0.38	0.25	0.39	0.39	0.42	0.45
	2030	0.22	0.04	0.10	0.03	0.03	0.02	0.00	0.18	0.13	0.19	0.19	0.21	0.22
	2031	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.04	0.04	0.04	0.05
	2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Winter	2021	10.09	1.66	5.05	1.24	1.15	0.76	0.23	8.43	5.04	8.85	8.94	9.33	9.86
	2022	15.21	2.50	7.54	1.89	1.76	1.17	0.35	12.71	7.68	13.32	13.45	14.04	14.87
	2023	17.53	3.02	8.27	2.29	2.13	1.42	0.41	14.51	9.26	15.24	15.40	16.11	17.12
	2024	14.16	2.41	6.44	1.99	1.91	1.06	0.36	11.75	7.72	12.17	12.25	13.10	13.80
	2025	11.66	1.67	5.36	1.72	1.70	0.89	0.32	9.99	6.31	9.94	9.97	10.77	11.35
	2026	8.04	1.20	3.55	1.23	1.21	0.64	0.22	6.84	4.49	6.81	6.84	7.40	7.82
	2027	5.02	0.81	2.19	0.76	0.74	0.39	0.13	4.21	2.83	4.27	4.28	4.63	4.89
	2028	3.55	0.60	1.54	0.53	0.52	0.28	0.09	2.95	2.01	3.02	3.04	3.28	3.46
	2029	2.17	0.37	0.94	0.32	0.31	0.17	0.05	1.80	1.23	1.85	1.86	2.00	2.11
	2030	0.97	0.19	0.41	0.14	0.14	0.07	0.02	0.79	0.56	0.83	0.84	0.90	0.95
	2031	0.09	0.02	0.03	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
	2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

This table indicates that the summer New England-wide value of G-E cross-DRIPE for 2021 is $1.96 per MMBtu. As with G-E cross-DRIPE, the winter value ($10.09 per MMBtu) is an order of magnitude larger because of the higher basis values in the winter months. For each state and year, the zone-on-Rest-of-Pool benefit equals the difference between the ISO-wide benefit and the zonal benefit. Table 102 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2018 and AESC 2021. As with other DRIPE categories relying on the price shift of natural gas supply, avoided costs for this category are lower in AESC 2021, compared to AESC 2018. This is primarily due to the reduced natural gas supply price shift, but it is also due to differences in projected loads and gas bases price shifts.

Table 102. Comparison of 10-year levelized electric-to-gas-to-electric (E-G-E) cross-DRIPE benefits (2021 $ per MWh)

	ISO NE	CT	MA	ME	NH	RI	VT
Electric Annual							
AESC 2018	-	-	-	-	-	-	-
AESC 2021	8.29	1.37	3.89	1.10	1.07	0.66	0.20
Difference ($)	-	-	-	-	-	-	-
Difference (%)	-	-	-	-	-	-	-
Electric Summer							
AESC 2018	7.10	1.55	3.48	0.68	0.72	0.53	0.14
AESC 2021	1.75	0.29	0.83	0.22	0.22	0.15	0.04
Difference ($)	-5.35	-1.25	-2.65	-0.46	-0.50	-0.38	-0.10
Difference (%)	-75%	-81%	-76%	-68%	-69%	-72%	-71%
Electric Winter							
AESC 2018	16.50	3.52	8.03	1.66	1.72	1.20	0.34
AESC 2021	8.95	1.46	4.18	1.22	1.17	0.69	0.22
Difference ($)	-7.55	-2.05	-3.85	-0.44	-0.56	-0.51	-0.12
Difference (%)	-46%	-58%	-48%	-26%	-32%	-42%	-35%

Note: Annual values were not provided in AESC 2018.

9.6. Oil supply DRIPE

Reducing demand for petroleum and refined products should lead to a reduction in oil prices. Oil demand may be lessened by further electrifying the transportation sector (oil-electricity substitution effects) or by reducing electricity demand during high load winter periods when oil is on the margin (oil-gas substitution). This reduction in oil prices induced by a change in oil demand is termed oil DRIPE.

Oil's global dimension makes modeling oil DRIPE more uncertain than the analysis of natural gas DRIPE. The analysis in Chapter 3: *Fuel Oil and Other Fuel Costs* relies on analysis of oil supply fundamentals which, in turn, does not consider the impact of oil supply disruptions or other sources of short-term volatility in oil price. For AESC 2021, we conduct a relatively high-level model of oil DRIPE in the following steps:

1) Estimate the relevant elasticity (i.e., the percentage change in oil price per percentage change in demand for crude oil).
2) Calculate the crude oil DRIPE value.
3) Calculate refined product DRIPE values using the ratios of crude-to-refined-product price from EIA's AEO 2021 for years 2021–2035.

Estimating elasticities

Elasticity describes how prices of a commodity respond to changes in demand. We use oil play breakeven analysis to estimate elasticity for crude oil.

Oil play breakeven analysis models the price at which a given geological formation is revenue neutral (a specific oil field or formation is known in the industry as a "play"). Different plays have different breakeven points, and when considered in aggregate, a supply curve can be made to show the prices at which various sources of new supply would enter the market. This curve can be thought of as analogous to an electric market's power plant offer stack.

By examining a set of these supply curves, we can assess the average relationship between price and supply for a marginal barrel of oil. Table 103 presents elasticities from five different breakeven analyses. Two of these curves display a supply curve with a very steep right tail. The Wood Mackenzie supply curve, for example, indicates that an additional million barrels per day of oil supply would increase breakeven price by about $3 per barrel. In other words, it indicates that a 1.0 percent increase in cumulative oil production in this region would increase costs by 0.36 percent.

Table 103. Percent change in crude oil price for a 1.0 percent change in global demand

Forecast	Curve Segment	Date Published	Elasticity	Sources
Wood Mackenzie	Entire curve	2016	0.36	(A)
Rystad Energy	Entire curve	2015	1.39	(B)
IEA	Entire curve	2013	2.00	(C)
Goldman Sachs	Low only	2012	0.47	(D)
Goldman Sachs	High only	2012	2.66	(D)
BP/PIRA	Low only	2015	0.88	(E)
BP/PIRA	High only	2015	3.60	(E)
Average (All)			**1.62**	
Average (Low Only + Entire Curve)			**1.02**	

Sources: (A) https://www.woodmac.com/news/editorial/pre-fid-oil-projects-commercial/, (B) https://www.rystadenergy.com/NewsEvents/PressReleases/global-liquids-supply-cost-curve, (C) https://www.financialsense.com/contributors/joseph-dancy/iea-shale-mirage-future-crude-oil-supply-crunch, (D) http://crudeoilpeak.info/oil-price-analysis, and (E) https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/news-and-insights/speeches/new-economics-of-oil-spencer-dale.pdf.

A simple average of all elasticities yields a value of 1.62. If the two "High only" slopes are removed, the resulting average elasticity is 1.02. Given the uncertain nature of this analysis, AESC 2021 models oil supply as unit elastic in the relevant region study, so a 1 percent change in demand would yield a 1 percent change in price.[265] Critically, demand in this context is *global demand* (currently 98 million barrels/day, of which the United States consumes about one-fifth).[266]

[265] The assumption of unit elasticity may overstate price effects because estimates of shale resources have increased in the past years and estimates of shale extraction costs have fallen—both effects reduce the slope of the supply curve, and its corresponding elasticity.

[266] For more information, see https://www.iea.org/oilmarketreport/omrpublic/.

This estimate is similar to our estimate of elasticity of supply for natural gas. This is expected given the similarities between the two hydrocarbons, their disposition, and their extraction.

Next, we convert this elasticity into a "price shift" which represents how the price (in dollars per MMBtu) that changes in response to changes in demand (measured in quadrillion Btu per year). To do this, we multiply the elasticity by a forecast for West Texas Intermediate (WTI) crude oil prices ($8 to $14 per MMBtu, depending on the year) and divide the result by a forecast of crude oil consumption (estimated to be about 220 quadrillion Btu worldwide).[267] This yields a price shift of about $0.05 /MMBtu per quadrillion Btus for any given year.

Calculating oil DRIPE

As with the electric and natural gas DRIPE effects, the price reduction per MMBtu of oil saved is very tiny compared to the price per MMBtu. But each MMBtu saved reduced prices for a very large number of MMBtus. That said, given the modest size of New England oil demand in comparison to the entire global market (about 0.7 percent of worldwide consumption), the overall value of DRIPE remains modest.[268]

According to the latest EIA SEDS database, in 2014 through 2018, New England consumed approximately 1.4 quadrillion Btu of petroleum products yearly.[269] Over time, AEO 2021 forecasts demand gradually falling, averaging about 1.2 quadrillion Btu of petroleum products yearly between 2021 and 2035.

As a result, a 1 MMBtu reduction in crude oil demand yields an average regional benefit of about $0.07 per MMBtu (i.e., $0.05/MMBtu per quadrillion Btu multiplied by 1.2 quadrillion Btu). The value for each state, presented in Table 104, are proportionally smaller, ranging from about $0.003 per MMBtu to $0.030 per MMBtu per 1 MMBtu reduction.[270] Zone-on-zone values are calculated based on each state's share of oil consumption relative to the New England-wide total. Meanwhile, zone-on-region values are equal to the New England total minus the value from each respective state.

[267] Crude oil prices are based on WTI prices from AEO 2021 and worldwide crude oil consumption is based on values in EIA's 2019 edition of the International Energy Outlook.

EIA. Last accessed March 11, 2021. "Petroleum and Other Liquids Prices." *Eia.org.* Available at https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

EIA. 2019. "Liquids Consumption: OECD: OECD Americas." *Eia.gov*. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=5-IEO2019&sourcekey=0.

[268] Calculated based on data from 2014 to 2018 using data from EIA. 2019. "State Energy Data System: Updates by Energy Source." *Eia.gov.* Available at https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US#DataFiles

[269] See https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US#DataFiles for more information.

[270] The United States consumes about 37 quads of petroleum products annually, compared with 1.4 quads consumed in New England. The value of a 1 MMBtu reduction in oil demand anywhere within the United States has a US-wide DRIPE value of $2.25 per MMBtu.

Table 104. Crude oil DRIPE by state (2021 $ per MMBtu)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.049	0.011	0.020	0.006	0.005	0.003	0.003	0.038	0.028	0.042	0.043	0.046	0.046
2022	0.052	0.012	0.022	0.007	0.006	0.003	0.003	0.041	0.031	0.045	0.047	0.049	0.049
2023	0.058	0.013	0.024	0.008	0.006	0.003	0.003	0.045	0.034	0.050	0.051	0.054	0.054
2024	0.061	0.014	0.025	0.008	0.007	0.004	0.003	0.047	0.035	0.053	0.054	0.057	0.057
2025	0.063	0.014	0.026	0.008	0.007	0.004	0.004	0.049	0.037	0.055	0.056	0.060	0.060
2026	0.065	0.015	0.027	0.009	0.007	0.004	0.004	0.050	0.038	0.056	0.058	0.061	0.061
2027	0.066	0.015	0.028	0.009	0.007	0.004	0.004	0.052	0.039	0.058	0.059	0.063	0.063
2028	0.068	0.015	0.028	0.009	0.008	0.004	0.004	0.053	0.040	0.059	0.061	0.064	0.064
2029	0.069	0.016	0.029	0.009	0.008	0.004	0.004	0.054	0.040	0.060	0.061	0.065	0.065
2030	0.071	0.016	0.029	0.009	0.008	0.004	0.004	0.055	0.041	0.061	0.063	0.066	0.067
2031	0.071	0.016	0.030	0.009	0.008	0.004	0.004	0.055	0.042	0.062	0.063	0.067	0.067
2032	0.072	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.064	0.068	0.068
2033	0.072	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.064	0.068	0.068
2034	0.073	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.065	0.068	0.069
2035	0.073	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.065	0.068	0.069
10-year levelized	**0.062**	**0.014**	**0.026**	**0.008**	**0.007**	**0.004**	**0.004**	**0.048**	**0.036**	**0.054**	**0.055**	**0.058**	**0.059**

Note: Values differ across states because states vary in terms of size of oil consumption.

As with natural gas supply DRIPE, oil DRIPE are not decayed. Because oil DRIPE is not decayed, the values in the preceding table reflect the actual value of a demand reduction in each year (e.g., a regionwide demand reduction in 2021 is worth $0.049 per MMBtu and a reduction in 2025 is worth $0.063 per MMBtu). Oil DRIPE benefits are low because of the relatively modest amounts of demand in New England states compared to the size of the global oil market.

In order to apply oil DRIPE values to specific commodities (e.g., gasoline, home heating fuel), we multiply the values in Table 104 by the refined-price to crude-price ratio found in Table 105. For example, the levelized value of gasoline DRIPE across New England is worth $0.108 per MMBtu reduced ($0.062 per MMBtu x 1.73).

Table 105. AEO 2021 prices of crude oil and refined petroleum products

Product	2021-2035 Avg Price (2021 $ per gallon)	Ratio of product price to WTI price
WTI Crude Oil	1.59	-
Home heating oil	2.77	1.75
Residual fuel oil	1.63	1.03
Motor gasoline	2.75	1.73
Motor diesel	3.21	2.03

Source: EIA AEO 2021 Table: "Petroleum and Other Liquids Prices." Available at. https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

This analysis assumes that oil supply drives the price of refined products and that a reduction in the demand of any petroleum product impacts the price of all other crude products. In reality, there may not be a one-to-one price benefit for reductions in gasoline on fuel oil (for example). This simplifying assumption is reasonable given the small magnitude of oil DRIPE effects and the high-level analysis undertaken.

Table 106 illustrates the differences between crude oil DRIPE calculated in AESC 2018 and AESC 2021. In AESC 2021, oil DRIPE values for New England as a whole are 27 percent lower than in the previous study. This change is primarily due to reductions in forecasts of crude oil prices and crude oil consumption.

Table 106. Comparison of oil DRIPE values (2021 dollars per MMBtu)

	New England	CT	MA	ME	NH	RI	VT
AESC 2018	0.085	0.022	0.032	0.011	0.011	0.011	0.007
AESC 2021	0.062	0.014	0.026	0.008	0.007	0.004	0.004
Difference ($)	-0.023	-0.008	-0.007	-0.003	-0.004	-0.008	-0.003
Difference (%)	-27%	-38%	-20%	-27%	-39%	-67%	-48%

Note: Values shown are levelized over 10 years. AESC 2018 uses a discount rate of 1.34 percent while AESC 2021 values use a discount rate of 0.81 percent.

10. Transmission and Distribution

In addition to avoiding various types of generation costs (energy, capacity, and associated DRIPE), load reductions can contribute to deferring or avoiding the addition of load-related T&D facilities, due to reduced load growth and reduced loading of existing equipment.[271] The chapter describes a methodological approach that program administrators can use to estimate avoidable T&D costs for planning and reporting of efficiency program benefits.

In AESC 2018, we developed a general framework for the calculation of avoided T&D values, including identifying general principles for such calculations. AESC 2018 also surveyed some of the sponsoring utilities (National Grid, United Illuminating, and Eversource Connecticut) for information on utility avoided T&D value estimates, along with the methods used to calculate those values. AESC 2018 separated PTF transmission for a separate treatment and developed an estimate of the value of avoided PTF transmission of $94 per kW-year in 2018 dollars ($99 per kW-year in 2021 dollars).

For AESC 2021, we present four separate threads for analysis of avoided T&D costs, building on the foundation established in the 2018 AESC and updating or expanding the analysis presented. The four aspects are:

1. Updating the avoided costs for PTF facilities using a forward-looking projection, rather than a historical estimate. The updated analysis finds an updated PTF value of $87 per kW-year in 2021 dollars.
2. Reviewing utility approaches to generic avoided cost values for non-PTF T&D and evaluating these approaches on a common evaluation rubric to facilitate cross-comparison and learning.
3. Reviewing utility approaches to calculating geographically localized avoided costs, such as for NWAs.
4. Developing an approach to the avoided cost of natural gas system T&D. See Section 2.4: *Avoided natural gas cost methodology* for more information on the assumptions used in AESC with respect to natural gas T&D.

In addition to evaluating different approaches to geographically localized avoided costs for NWAs as a standalone aspect of analysis, AESC 2021 examines across each aspect whether the appropriate treatment or calculation of T&D avoided costs differs for other specific technology types or program applications, such as distributed generation and electrification or other fuel switching programs. AESC

[271] Many energy efficiency programs will be cost-effective without consideration of avoided T&D costs, and many load-control programs will not reliably reduce peak loads on T&D equipment. These will not be eligible to be credited with avoided T&D equipment. For some energy efficiency measures and programs, especially those with very peaky load shapes, the avoided T&D costs may be critical in demonstrating cost-effectiveness.

2021 address the locational value of potential services provided by efficiency and other DERs; we do not address programmatic or other barriers to using DERs to address T&D costs.

This section begins with an overview of the recommended approach for calculating avoided T&D costs, which can then be tailored to the specific situation for which costs are to be calculated. We then proceed through the different aspects and scales of such analysis in New England, beginning with region-wide PTF. The subsequent two sections address avoided T&D at smaller scales: first for a utility service territory or other program-wide jurisdiction, and then for specific locations on areas within a service territory which may warrant location-specific avoided T&D values due to an existing constraint. For each of these scales, we present an evaluation of the relevant methods currently used by utilities within the region. The section concludes with an analysis of the equivalent structure for natural gas distribution (see Section 2.4: *Avoided natural gas cost methodology* for more information).

10.1. General approach to estimating the value of system-level avoided T&D

The following steps, unchanged from AESC 2018, summarize a standardized approach to estimate generic system-level avoidable transmission or distribution costs:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two.
- Step 2: Determine the actual or expected relevant load growth in the analysis period, in megawatts.[272]
- Step 3: Estimate the load-related investments in dollars incurred to meet that load growth.
- Step 4: Divide the result of Step 3 by the result of Step 2 to determine the cost of load growth in $ per MW or $ per kW.
- Step 5: Multiply the results of Step 4 by a real-levelized carrying charge to derive an estimate of the avoidable capital cost in $ per kW-year.
- Step 6: Add an allowance for operation and maintenance of the equipment to derive the total avoidable cost in $ per kW-year.

The data for this approach may come from historical top-down accounting data, such as from page 206 of the utility's annual FERC Form 1 filing, or from bottom-up data based on past and future expenditures by project or budget line item.

These generic avoided T&D costs are not intended to represent the potential value of targeted load reductions, as part of NWAs to specific T&D projects. Analysis of targeted NWAs requires information

[272] The data could be for hypothetical growth levels, but the effort of determining the investments necessary to meet a hypothetical growth level is likely to be excessive. Hence, most analyses rely on actual investments (which are known) or fully developed investment projects for the relatively short-term future.

about the cost and timing of the specific project to be avoided and the amount of load reduction required to defer project need for one or more years. The methodology for localized value of avoided T&D is the subject of Section 10.4 below.

The goal of these generic avoided-cost computations is not to identify specific projects that can be avoided, but to estimate the overall, long-term ratio of T&D savings per kW of avoided load growth (and hence of a kW of peak savings).[273] Under this approach, historical data can be as meaningful as forecast data, and the sunk costs of planned additions are as relevant as the future costs.

The avoided T&D value is generally applied as if every kW of load reduction in any location will have the same value. This is a useful simplification, which is reasonable for widespread energy efficiency programs. In some places and times, even small load reductions that keep load below the capacity of existing equipment may defer or avoid very large incremental T&D investments. In other places and times, relatively large load reductions may have little effect on T&D investments. The location contributing to new T&D investments can vary from perhaps a dozen residential customers sharing a line transformer to thousands of customers sharing a substation or a transmission line. Since avoidable T&D costs are estimated as the ratio of actual or near-term expected investment to actual or expected load growth, the specific past projects used in the analysis were not usually avoided, and near-term future projects may also not be avoided.

Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may defer or avoid the addition of a line transformer in the next year. It may also contribute to delaying or avoiding the reconfiguration of feeder, the upgrading of a substation, and the construction of transmission lines in following years. At another location, load reductions may have little effect on T&D investment for many years. Recognizing this complex dynamic, the general approach in this report computes the average ratio of all load-related investments to all load growth, rather than just the load growth that has the greatest effect on investment to develop avoided costs.[274]

The methods and approach described here are generally independent of the technology or program that changes peak load. For example, the value of avoiding transmission investments does not depend on whether the peak was reduced by energy efficiency, demand response, or distributed generation—as long as the peak reductions are the same. It is also critical that the peaks in question are the same peaks: if transmission needs are driven by a summer system-wide peak, or distribution needs are driven by a winter morning, then the characteristics of a given measure or program at those times are what matter for avoiding expenditures. The marginal benefit of reduced peak should also be the same as the marginal cost of increased peak: electrification measures that increase a peak that is relevant for T&D

[273] Analysts do not generally have *ex post* estimates of costs that have actually been (or are expected to be) avoided by energy efficiency; such analysis, if feasible, would usually be prohibitively expensive.

[274] Geographically targeted load reductions, such as part of an NWA to a transmission or distribution project, may have much higher values, depending on the magnitude and time of need, as discussed in more detail in Section 10.4.

infrastructure planning will, on the margin, create costs at the same rate (in $/kW) that load reduction measures reduce them. Note that time coincidence matters for electrification as well as energy efficiency: electrification measures that increase a winter peak do not cause T&D expenditures if those expenditures would be driven by the need to meet loads at a summer peak.

The remainder of this section provides an overview of background, context, and considerations to be kept in mind and used as guidance in developing avoided T&D values. The following two subsections apply these lessons and guidance to PTF transmission (Section 10.2) and to evaluation of the methods used for generic avoided T&D in the region today (Section 10.3).

Criteria for avoided T&D estimation

The following considerations are useful in guiding the estimation of avoided T&D costs:

- **Time period.** In estimating the avoided T&D cost, any analysis should use data from complete, consistent, and reasonable time periods for both load and investment. It may be useful to align these timelines with those used for distribution planning and capital investment planning processes.
- **Investment plans and budgets for any future period must be reasonably complete.** It is important to capture all of the expected T&D costs along with all of the expected changes in load within the period selected for analysis. Investment plans that include only a portion of projected costs (for example, those associated with only larger projects with long lead times) should not be the only source of cost information.
- **The analysis period should provide a reasonable proxy for the long-term relationship between load and investment.** If the period starts with the system overbuilt due to unexpected load reductions, the analysis will tend to understate the cost per kilowatt and vice versa. The analysis should avoid or correct for unrepresentative conditions due to unexpected growth or deferred investments.

On a related point, adjusting the loads to account for the weather conditions is likely to be more representative than actual loads in determining the amount of load growth in the analysis period, so weather adjustment may be necessary. Taking actual load growth between a hot summer with high loads and a subsequent mild summer with low loads would understate the amount of load growth driving the investment, and vice versa.

Some T&D investments are driven by load growth from new customers in areas that are not currently served, or are not served in a manner that would accommodate the growth, even with very aggressive energy efficiency efforts in new and existing loads in the area. For example, serving major commercial development in a previously residential exurban area or a 100-unit residential development in an agricultural area may require a new substation or feeder respectively, regardless of any conceivable load reduction. Analyses of avoided T&D costs generally omit these projects; where possible, the load growth served from these projects should also be omitted from the computation.

Even utility systems with little total load growth tend to have areas in which peak loads are growing, offset by areas in which peak loads are declining (due to some combination of energy efficiency programs, other conservation, and economic and demographic trends). In those situations, the computation of avoided T&D costs should ideally represent the investments in the growing areas, divided by load growth in those same growing areas. This greater level of detail is rarely possible, especially on a feeder-specific or transformer-specific basis.

Investments should be converted to some common price basis (such as by adding or removing inflation) so that investments in differing years (e.g., 1997, 2007, 2017, and 2027) can be added together. Any projections or hypothetical adjustments to the historical periods should be handled consistently for load growth and investment.

The AESC avoided costs are based on hypothetical worlds in which no energy efficiency programs (and/or no other load management or electrification programs) are implemented going forward. For consistency in identifying the full T&D costs avoidable by energy efficiency programs, it would be desirable to start with the loads that would have occurred and the investments that would have been needed without energy efficiency efforts. Estimating the effect of the energy efficiency programs on historical and forecast loads may be feasible. Unfortunately, estimating the T&D investments that would have been needed without the energy efficiency programs is generally infeasible, requiring a large amount of engineering analyses to develop hypothetical needs at the feeder level.[275]

If a fully consistent no-energy efficiency (no-EE) analysis could be performed, that would be ideal. But an analysis that combined loads from a "no-EE" premise with investments from the "with-EE" reality would understate avoidable costs.

Disaggregation of growth

For each type of equipment, the computed load growth should reflect the load on that type of equipment. The T&D system consists of several types of equipment, which may be simplified into the following categories:

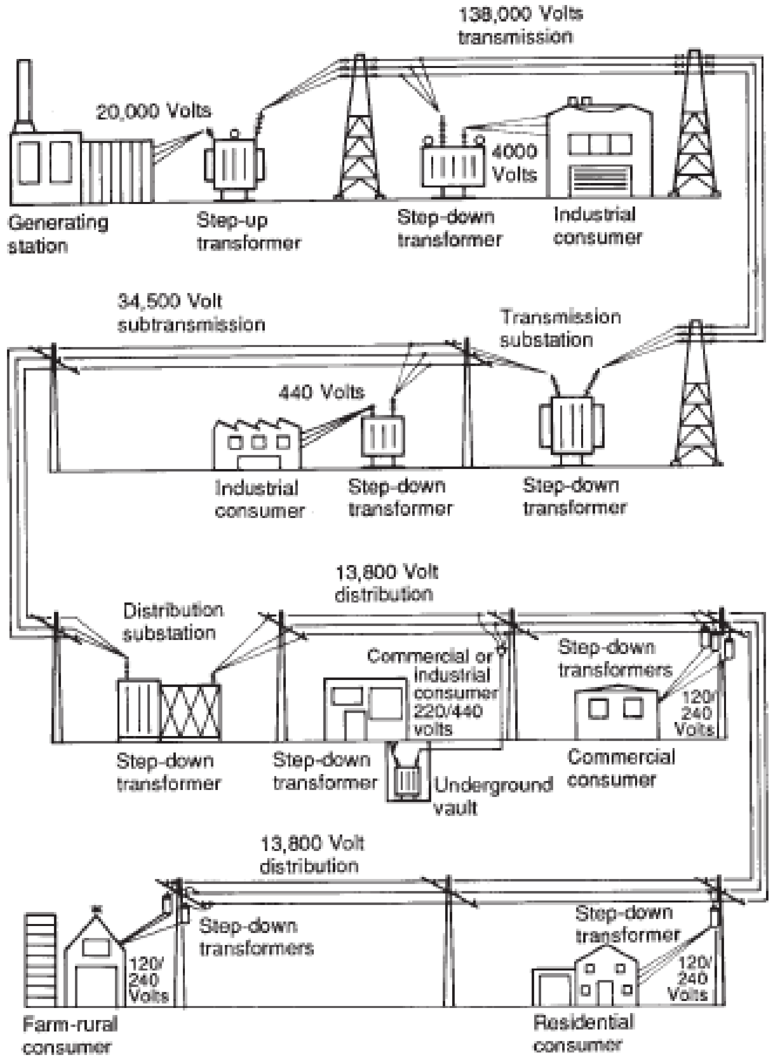
- high-voltage transmission lines (115 kV to 345 kV);
- transmission substations connecting transmission lines at different voltages;
- subtransmission lines (e.g., 69 kV) that connect to distribution substations and some very large customers;
- bulk distribution substations that step transmission voltages down to generally high distribution voltages (mostly at 13.8 kV to 25 kV);

[275] The actual and projected energy efficiency may have avoided the planning and construction of more expensive T&D projects, but those costs are not generally available. The available data generally estimates the benefit of additional load reductions, on top of those that have occurred and are planned.

- high-voltage primary feeders that distribute power from the bulk substations to lower-voltage substations, some primary-voltage customers, and line transformers;
- lower-voltage substations that step down the power to lower (mostly legacy) voltages, in the 2 kV to 8 kV range;
- low-voltage primary feeders that distribute power to primary-voltage customers and line transformers;
- line transformers that step power down from the primary distribution voltages (2 kV to 35 kV) to secondary voltages (110 V to 500 V);
- secondary lines from the transformer customer service drops; and
- service drops from the street to customer meters.

Figure 51 illustrates the general design of T&D systems. The range of voltages considered to be subtransmission varies among utility systems.

Figure 51. Schematic of a T&D system



Source: Electric Power Generation, Transmission and Distribution eTool. United States Department of Labor. Available at *https://www.osha.gov/SLTC/etools/electric_power/illustrated_glossary/*.

Any load reduction may result in avoidance or delay of investments at one or more of these levels, in the near term or over many years.

All loads use transmission; primary and secondary loads use the primary distribution system; and only secondary loads uses line transformers and secondary lines. Hence, T&D analyses should use the peak loads applicable to the transmission or distribution capacity appropriate to the particular analysis.

Computation of T&D avoided costs

Generally, the computation of avoided costs in $/kW should use the same measure of load that will be used in screening. This criterion requires that the units of load reduction used to attribute avoided costs to programs be consistent with the units of load used to compute those avoided costs. The units should be consistent on a number of dimensions, including the timing of the load peaks, the treatment of seasonal load, the use of normal or extreme loads, and the treatment of losses.

Generation capacity avoided costs are driven by load at the time of the ISO New England peak, which has by convention been associated with an hour ending at 3 p.m. or 5 p.m. on a hot summer day. For simplicity, energy efficiency screening often uses these same peak conditions for estimating contribution to T&D peaks, in which case the avoided T&D costs should be computed per kilowatt of growth in contribution to regional peak. Since T&D assets reach their peak loads at different times, in both summer and winter, some utilities may use a different measure of peak load (e.g., sum of class peaks, sum of summer and winter peak) to derive the $/kW ratio, in which case that alternative measure of peak load should be used for valuing the T&D savings in the screening process.

If the avoided T&D costs are to be allocated between summer and winter peak contributions in screening, then the avoided-cost analysis should similarly reflect both summer and winter load growth. Assuming that winter peak growth equals summer peak growth is rarely realistic.

Transmission and some distribution facilities are planned for extreme weather (or other conditions), such as those in the ISO New England's 90/10 load forecasts. It may thus be tempting to divide investment by the growth in load that would occur under extreme conditions, rather than normal peak conditions (e.g., those that would be expected to be exceeded about half the time). If the analysis computes avoided T&D costs in $\$/kW_{extreme}$, screening must use estimates of load reduction under extreme conditions. For some end-uses, load reductions will be very similar at normal and extreme peaks, but for others (air conditioning and solar in the summer, heating in the winter) the reductions under extreme conditions will exceed those at normal peaks.[276] If screening assumptions cannot be developed for extreme conditions, analysts should avoid the use of extreme loads in the avoided-cost analyses. Note that this may mean using different weather for the purposes of demand-side measure evaluation than is used for T&D system planning, and tracking different "flavors" of peak load or developing equivalency relationships may be required.

Similarly, if screening uses load reduction at the end-use, the avoided T&D costs should use load growth at the end-use. If this apples-to-apples structure is not possible (such as if load growth is measured at transmission level) the appropriate loss factor must be added to the avoided cost.

Identifying load-related investments

The investment should include all identifiable load-related costs, but no more. AESC 2021 recommends using top-down accounting analyses to identify the accounts that are primarily load-related,[277] and net

[276] Something must use more energy at the extreme peak, or it would not be an extreme peak.

[277] As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in the methodology for identification of load-related investments that can be avoided through DERs and applicability to more feeders. The methodology described in AESC 2021 is based on identifying load-related investments using current distribution system planning practices.

out an allowance for the costs of replacing retired equipment in kind. The FERC Form 1 data include both additions and retirements by account. Bottom-up analyses should be used to identify the projects and blanket accounts that are primarily load-related.[278]

For the bottom-up analyses, AESC 2021 recognizes that differentiating investments between those required by load growth from those required for other considerations can be complex. The non-load-related investments may include:

- Distribution assets (primarily meters and services) that are driven entirely or predominantly by the number of customers.[279]
- Primary distribution projects that extend service into areas that have not previously been served, to connect new customers. New construction energy efficiency programs may avoid a small portion of the wire costs. However, most of the costs are related to the extension of supply to new areas.
- Some transmission projects that are required to integrate generation or allow targeted imports. Generation interconnection costs will generally be included in the generation market prices. Transmission projects supporting policy-driven imports of renewable energy from Canada or offshore wind are unlikely to be affected much by load reductions, at least in the short term.[280]
- Some T&D investments simply replace old equipment. Other investments relocate facilities due to road widening, loss of easements, and similar factors. Neither type of investmetns are load-related.

In contrast, other investments are clearly required to accommodate load growth, including:

- Most new transmission lines and substations and additional transformers at existing substations;
- Additional feeders and line transformers in areas with existing service;
- Reconductoring of lines to increase capacity;
- Increasing the voltage of transmission or distribution lines; and
- Conversion of single-phase feeder branches to two-phase or three-phase operation.

[278] A blanket account in the context of distribution utilities typically includes a large number of similar investments, such as substation upgrades or line-transformer replacements.

[279] Service drops are often sized or upgraded based on the end-uses in a building. In principle, energy efficiency should reduce the required service size and cost. It is not clear how consistently utilities or contractors take building efficiency into account in determining the size of the service drop to be installed.

[280] Energy efficiency measures installed in the near term may (by reducing the use of fossil generation) reduce the motivation for further clean-import mandates and associated generation. Predicting the timing of future initiatives may be challenging.

A third set of investments is harder to characterize, including such situations as:

- Investments triggered by factors other than load, but whose cost are increased to accommodate higher load levels. For example, if rotting poles are being replaced with taller poles so that the feeder voltage can be increased in the future, the incremental cost of the taller poles is load-related. The cost of replacement may be unavoidable, but the load-related improvement may be avoidable.[281]

- The costs of removing aging, but functional equipment to allow installation of higher-capacity equipment. The existing equipment might need to be replaced in another decade or two, even without the load growth, but most of the present value of the replacement cost would be due to the load-related timing of the project.

- Investments required to complete or modernize projects already in service, such as improved lightning arrestors or added SCADA equipment on existing feeders. These investments may be considered as a continuing cost of the original load-related projects (as post-operational capital additions are considered part of the cost of a power plant), and hence an adder to avoided cost (perhaps computed in dollars per MW of load, rather than dollars per MW of load growth). On the other hand, if the improvements are being driven by a one-time change in reliability or safety standards or technology, perhaps no similarly deferred improvements should be anticipated for equipment driven by future load growth.

- Replacement of equipment degraded by both age and loading levels. For example, high loads (especially high loads over many hours in a day) increase the rate at which insulation breaks down in underground lines, substation transformers, and line transformers. High loads on transmission lines also increase the line sag (possibly violating clearance requirements) and weaken the conductor. Replacements of load-carrying equipment will generally be at least partly driven by load levels, but the extent of this effect may be difficult to separate from the effects of time.

- Investment driven by load-related energy considerations, including transmission congestion relief and reduction of line losses.[282]

AESC 2021 recognizes that these situations complicate the neat division of projects and accounts into load-related and non-load related categories. Classification of specific projects or accounts as avoidable or unavoidable by energy efficiency should be clearly documented and explained.

Matching investment to load growth

Bottom-up analyses should include all the investment in load-related equipment entering service in the analysis period, including investment prior to the start of the analysis period. Any project costs that

[281] In principle, the decision not to downsize the replacement may also be load-related, but the incremental component of project cost may be difficult to quantify.

[282] Line losses should be computed on a marginal basis, where possible.

stretch beyond the in-service date of the equipment (e.g., for removal of retired equipment, environmental compliance, addition of communications or control equipment) should be included as well. Top-down accounting-based data will include all the costs of a project in the year that the project enters service but may count some deferred costs in the following year.

The load growth used in computing avoided distribution costs should reflect the loads at the distribution level, excluding loads served directly from transmission lines, for which the utility does not provide distribution equipment. Similarly, where the avoided cost of secondary distribution is computed separately from the primary distribution, the load growth should reflect only the loads served at the secondary distribution level.

While the load growth used in computing avoided distribution costs should reflect the loads of customers served at distribution, the growth in distribution loads may be stated in terms of megawatts at the transmission level, at the distribution level, or at the meter.[283] Contribution of distribution loads to system or area peaks are highest when measured at the transmission level, lower at the distribution level, and still lower at the customer's meter. This is because the transmission-level loads include line losses from the meter to transmission, distribution-level loads include line losses from the meter to the feeder or substation, and loads at the meter include no losses. As a result, the avoided costs will be higher measured as $ per kW at the meter and lowest as $ per kW measured at transmission. Since energy efficiency program load reductions are generally estimated at the end-use, the cost-benefit analysis must reflect avoided costs at the end-use (or the customer meter, as a proxy for the end-use). If the avoided cost is computed per kilowatt of load data at the transmission level, rather than using end-use load, losses from the meter to transmission must be added back to get the avoided cost in $/kW of load at the meter.[284]

Investments in T&D infrastructure to support load growth generally do not increase the capacity of the relevant portions of T&D system by only the exact amount of projected load growth. Instead, it is typical to use standard equipment (which may be larger than strictly necessary) or to design in an allowance for future growth over the multi-decade useful life of a piece of infrastructure. For example, the aggregate capacity of all of a utility's distribution infrastructure often far exceeds the sum of substation peak loads. When matching the load growth to the investment, it is therefore necessary to determine whether the relevant capacity is the increase in peak load, or the increase in capacity of the relevant portion of the T&D system.

The only choice that is consistent with an avoided cost formulation for demand-side measures is to use the actual growth in peak load, rather than the capacity of the new hardware. This is because the load avoided by a demand-side measure is the actual peak load. If the avoided T&D value were calculated by

[283] Regardless of where load is measured, it should include only the contribution from the voltage levels driving the need for that type of equipment (i.e., all distribution load for substations and feeders, secondary load for transformers).

[284] Similarly, if the load growth is estimated at a distribution voltage, the avoided cost must be increased by the losses from the meter to that voltage.

dividing the infrastructure cost by its additional peak capacity (that is, if the value were in units of \$ per $kW_{hardware}$) then when multiplying this value by the peak reduction produced by an energy efficiency program ($kW_{end\text{-}use}$) the calculation would understate the value of efficiency by a ratio of $kW_{hardware}$ per $kW_{end\text{-}use}$. In addition, the extent of overcapacity built into hardware once the decision is made to construct is entirely independent of the incremental peak capacity that caused the decision.

For example, take a load-growth-related investment with an annual carrying cost of \$100,000 that is caused by an increase in load of 100 kW, but increases the capacity of the relevant portion of the grid by 1 MW. If the avoided cost value were based on the hardware installed, it would be \$100 per $kW_{hardware}$-year, while if it is based on the load, it would be \$1,000 per $kW_{end\text{-}use}$-year. If load were actually reduced by 100 kW through a demand-side intervention, these two avoided cost calculations would imply different values of the avoided cost: \$100,000 per year in the end-use case and only \$10,000 per year in the hardware case. Since we know that the \$100,000 per year investment would have been avoided by the 100 kW load reduction, only the load-derived calculation can be correct.

While in theory a generic ratio of $kW_{end\text{-}use}$ to $kW_{hardware}$ could be used to adjust for this effect, when combining many such decisions across time and across a service territory, consistency and coherence in the meaning and scale of $kW_{hardware}$ would almost certainly be lost. Therefore, the calculation of avoided T&D costs should use the actual kW of load, rather than the kW of new hardware capacity.

Dealing with absence of system load growth

As noted previously, some utilities have experienced little or no overall growth in total load for some years and may forecast little growth in peak loads for some years. Nonetheless, utilities can have load-related investments to address parts of their service territories that are experiencing load growth. Dividing the load-related investments by zero, a negative number, or even a small positive load growth will produce meaningless results. In those situations, a utility may either use historical data from a period with load growth, or compute the avoided cost per kilowatt growth for the fraction of the system that has experienced growth.[285] The AESC Reference (Scenario 1) case assumes a world with no new energy efficiency, no active demand management, and no building electrification programs, in which the avoided costs computed for the areas with growth would be applicable to the entire utility.

Carrying cost

The annualization of the capital costs should reflect the utility's cost of capital, income taxes, property taxes, and insurance. The useful life used in determining the carrying charge should match the expected life of the equipment. If a transmission plant has a longer operating life than distribution plant, the analysis should use a lower carrying charge for transmission than distribution. This is one reason that avoided transmission and distribution are usually computed separately.

[285] We are unaware of any utilities that have estimated what capital expenditures would have been without historical DSM effects or what capital expenditures would be in the absence of future DSM effects.

The carrying charge should be computed in $/kW-year levelized in real terms. The real-levelized carrying charge is the first-year charge that, if escalated at the inflation rate, will have the same present value as the revenue requirements for the project or the nominally levelized charge. The real-levelized carrying charge in each year represents the present value benefit of a one-year delay adding the investment, and hence a one-year reduction in load growth.

Annual revenue requirements, real-levelized costs, and nominally levelized costs have the same present value, but the revenue requirements are front-loaded. Nominally levelized costs are flat in nominal terms and real-levelized costs are flat in real terms, rising with inflation.

Operation and maintenance

Most T&D plant additions (a new transmission line, substation, feeder, or line transformer) also incur additional O&M costs, such as for vegetation control, inspections, repairs, repainting of towers and structures, and the like. Some expenditures, such as reconductoring a feeder or replacing poles for a voltage upgrade, may not increase (and may actually decrease) O&M costs.

The best practice for extrapolating O&M from historical data would generally be to determine the unit O&M cost ($/MVA of substation operation and maintenance, $/mile of feeder) and apply that value to the avoided cost. That process is straightforward for additional substations and transmission lines, which have their own accounts in the FERC Form 1. But it would be more difficult for other distribution facilities for which O&M expenses are less clearly delineated. It is generally reasonable to assume that the ratio of O&M cost to gross plant for the avoidable capacity is the same as for the existing plant mix, although ideally the historical investments would be restated to include inflation.[286] Any assumption that O&M associated with new equipment is less than the average O&M for similar existing equipment should be carefully considered and fully justified.

In addition to avoiding new facilities and their O&M, lower loads will also tend to reduce the rate of failures of existing equipment and thus the capital and O&M costs involved in repairing and replacing the damaged equipment.

Overheads

Utilities generally allocate a range of overhead or administrative costs (e.g., senior management, legal, financial, human resources, purchasing and contracting, information technology, warehousing, office expense, vehicles) on labor or a similar broad measure of O&M and construction costs. Some of those overheads may not vary linearly with the number of personnel required to design, build, maintain and operate the assets, but increased construction will generally require more of the overheads as a whole.

[286] “Gross plant” is defined as the total capital assets dedicated to utility service and is used to determine rate base.

The utility's overhead adders should be included in both the load-related investments and the associated O&M. Any exclusion of overhead costs from avoided T&D investment should be carefully considered and fully justified.

10.2. Avoided pool transmission facilities transmission

All load in New England pays for PTFs, in addition to local facilities in the local networks. AESC 2018 used ISO New England's then-current Transmission Cost Allocation (TCA) data to identify $6.7 billion (in 2018 dollars) in load-related investments in substations, new lines, voltage upgrades, and additional capacitors and transformers for projects completed or planned for 2003 through 2020, plus two small projects planned for 2021 and 2024. Using the most expansive interpretation of the actual and projected load growth that would have justified those investments, AESC 2018 estimated the avoided PTF cost as $94 per kW-year in 2018 dollars (equal to $99 per kW-year in 2021 dollars).

After the completion of AESC 2018, several stakeholders raised a concern that the analysis was backward-looking rather than prospective. To address this concern, we reviewed the projects in the October 2020 Draft Regional System Plan (RSP) Project List, which includes descriptions and estimated costs for projects under construction, planned or proposed through 2023, plus two small projects planned for 2024 and 2026.[287] This listing may contain some projects that will never be approved, but it probably does not include all the projects that will be scheduled through 2023, let alone 2026. The October 2020 RSP Project List update added several projects proposed for service as early as December 2021, so more projects are likely to eventually be proposed for 2023–2026.[288]

We do not have data on the amount of past and projected load growth driving these transmission expansion plans. The overall ISO New England peak loads are declining, due in part to the energy efficiency programs. However, loads in some areas have been growing and are expected to continue growing, justifying addition of the RSP load-related projects.

Lacking detailed data on the recent projected load growth for which the RSP projects are proposed, we examined whether the proposed annual rate of PTF additions is comparable to the annual rate of PTF additions in the historical data used in the 2018 AESC analysis. Specifically, we computed the apparently load-related expenditures by year for the historical data and the projected RSP costs. For the future-looking RSP costs, we excluded any projects listed as under construction in the ISO England October 2020 project list to make the computation entirely forward-looking.

[287] ISO New England. October 2020. *ISO-New England Project Listing Update*. Available at https://www.iso-ne.com/static-assets/documents/2020/10/final_project_list_october_2020.xlsx.

[288] Several other projects planned for completion in the early 2020s in the October RSP Project List were first proposed in 2018 through early 2020. Costs of projects currently proposed, planned, or under construction may rise by the time the projects are completed.

Table 107. Comparison of annual load-related additions, historical and projected (2021 dollars)

Historical Project Costs (based on TCA)			Future Project Costs (based on RSP)		
period	*$M*	*$M/year*	*period*	*$M*	*$M/year*
2003-2020	$7,008	$389	2021-2023	$991	$330
2003-2024	$7,050	$321	2021-2026	$1,074	$179

The historical TCA data appear to be quite comprehensive through 2018 (the last year containing actual cost data) and even through 2020, and then became sparse. Similarly, the RSP data appear to be complete through 2023 (with 37 reliability projects) and thin thereafter (with only one project scheduled for 2024 and another for 2026). Between June and October 2020, 13 load-related projects totaling $126 million were added to the RSP with in-service dates of 2021 to 2023, in addition to the two later projects, with an estimated cost of $84 million.[289] It is likely that additional projects will be added for in-service dates after 2023. Excluding the thin and incomplete tails (post-2020 for the historical costs and post 2023 for the projected costs), projected future annual investments are equal to 85 percent of the historical investment-per-year rate ($330 million per year, compared to $389 million per year in as estimated in AESC 2018).

We assume that the forecasted localized load growth underlying the future RSP budgets is comparable to the historical load growth driving the historical TCA projects. As a result, we calculate an avoided PTF cost for future years by multiplying the value derived in AESC 2018 by 89 percent. This yields a value of $84 per kW-year in 2021 dollars. Regional transmission needs are driven, and have been driven, by summer peak loads. Therefore, the regional PTF value should be applied to evaluation of measures that change the summer peak.

10.3. Survey of utility avoided costs for non-PTF transmission and distribution

AESC 2021 includes a new rubric to evaluate and compare the methodologies for non-PTF avoided T&D used by utilities in the Study Group. AESC 2018 included a discussion of methods used by several utilities (National Grid, United Illuminating, and Eversource Connecticut). AESC 2021 builds on that structure by formalizing this rubric. This rubric is based on the parameters and areas detailed in Section 10.1 above. The key areas of evaluation rubric include:

1. Load (whether past, forecast, or a combination);
2. Identifying which expenditures are avoidable or deferable by changes in load (e.g., are "load-growth-related");
3. Matching the changes in load to the load-growth-related investments (e.g., in time);

[289] Dollar years are not indicated in the RSP document. Because some spending may be underway today, because there may be a mix in reporting dollar years in terms of current real dollars and future-year nominal dollars, and because the inflation over the 2021–2026 is minimal, we assume that all spending is in 2021 dollars for purposes of simplification.

4. Mapping lumpy investments to an annual value; and
5. Inclusion of other costs associated with T&D investments, such as O&M and overhead.

Evaluation of current utility methods

The following describes our review of data provided by participating utilities that informs the T&D avoided cost quantification approach. Below, we present summary tables of the evaluation rubric, applied to each utility that responded to the request for information about their current avoided T&D cost calculation methodologies. Table 108 summarizes the avoided T&D values currently in use. Table 109 provides a summary of the load forecast methodologies used in developing these avoided T&D cost values. Table 110 provides more detailed methodological considerations used in deriving the avoided cost values.

Table 108. Summary of utility avoided T&D cost methodologies

Criterion		Eversource		National Grid		UI	Vermont	Maine	Unitil
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*	*MA*
In evaluating or screening DSM, does utility have a method for valuation of avoided distribution costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
The existing value of avoided distribution costs used by utility in evaluating and screening DSM	\$14.05/kW (2018\$)	\$198/kW (2018\$)	\$79.98/kW (2018\$)	\$102.48/kW (2019\$)	\$80.24/kW (2019\$)	\$30.29/kW (2017\$)	\$0/kW-Yr	Mid Value: \$246.79 (nominal)	\$222.56 (2018\$)
The year in which avoided distribution cost was developed	2018	2018	2017	2019	2019	2017	2018	2020	No data available
Frequency at which avoided distribution cost is updated by utility	No regular frequency	Every 3 years	No regular frequency	Every 3 years	With AESC Update	No regular frequency	No regular frequency	No regular frequency	No data available
In evaluating or screening DSM, does utility have a method for valuation of avoided transmission costs	Yes (PTF and Non-PTF)	Yes (PTF only)	Yes (PTF only)	Yes (PTF only)	Yes (PTF only)	Yes	Yes (PTF only)	Yes	Yes
The existing value of avoided transmission costs currently used in evaluating and screening DSM	Applies \$1.03 \$/kW-Yr in addition to \$94/kW-yr	\$94/kW-yr	\$94/kW-yr	\$94/kW-yr	\$94/kW-yr	\$0.84/kW-yr	\$94/kW-yr (Efficiency VT); \$45/kW-yr (BED)	Mid Value: \$56.88/kW-yr + PTF (\$94/kW-yr)	\$94/kW-yr
The year in which avoided transmission costs were developed	2018	2018	2018	2018	2018	2017	2018 (Efficiency VT); 2012 (BED)	2020	2018
Frequency at which avoided transmission costs are updated	No Regular Frequency	With AESC Update	With AESC Update	With AESC update	With AESC update	No Regular Frequency	With AESC update (Efficiency VT) No Regular Frequency (BED)	PTF portion with AESC update	With AESC Update

Notes: Methodology for Maine represents EMT's proposed approach. For details on Unitil's approach, see D.P.U. 18-110 – D.P.U. 18-119 Three-Year Plan 2019-2021, October 31, 2018 Exhibit 1, Appendix C - Electric Page 36 of 43 https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf.

Table 109. Avoided T&D load forecast methodologies

Criterion	Eversource			National Grid		UI	Vermont	Maine
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*
Load forecast granularity used in calculating avoided costs at a utility-wide level	Transmission and Substation	Transmission and Substation	Transmission and Substation	Transmission and Supply area level	Transmission and Supply area level	Transmission Level	Transmission (Based on AESC)	Based on data available from CMP
Inclusion of the following in load forecasts:								
Operational EE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Based on data available from CMP
Operational PV	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
Operational DR	Yes	Yes	Yes	Yes	Yes	No	No	
Inclusion of the following in load forecasts:								
Projected EE	Yes	Yes	Yes	No	No	Yes	Yes	Based on data available from CMP
Projected PV	No	No	No	Yes	Yes	Yes	Yes	
Projected DR	Eversource sponsored programs only	Eversource sponsored programs only	Eversource sponsored programs only	Yes	Yes	No	No	
Inclusion of any electrification goals or mandates reflected in current policy	No	No	No	Yes	Yes	No	Yes	Based on data available from CMP
Existence of a process for identifying expenditures *avoidable* through load reductions	Yes	Yes	Yes	Yes	Yes	Yes	No	Based on data available from CMP
Existence of a process for identifying expenditures *deferrable* through load reductions	Yes	Yes	Yes	Yes	Yes	Yes	No	Based on data available from CMP

Notes: In Massachusetts and Rhode Island, National Grid excludes projected energy efficiency beyond the current plan in its forecast for determining the value of avoided distribution costs for DSM. It does account for continued lifetime savings from the current and prior plan years with a decay rate over time.

Table 110. Detailed considerations for calculation of load-specific avoided T&D costs

Criterion	Eversource			National Grid		UI	Vermont	Maine
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*
Existence of a process for deciding years of expenditure that factor into avoided transmission and distribution cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Based on data available from CMP
Use of the following when calculating avoided T&D costs (past values/future values/combination of past and future)	Combination	Combination	Combination	Combination	Combination	Combination	N/A - using AESC avoided PTF	Based on data available from CMP
Existence of a process for matching load levels to load-growth-related investments	No	No	No	No	No	No	N/A - using AESC avoided PTF	Range of values presented matching load levels to investments.
Whether utility applies a carrying cost to these investments to annualize investment values when calculating the avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes
Whether utility applies avoided O&M costs associated with investments when calculating avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes
Whether utility applies an avoided overhead cost associated with investments when calculating avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes

The following sections present short descriptions of the methods used by each responding utility.

National Grid (Massachusetts and Rhode Island)

National Grid calculates its avoided distribution capacity values for both its Massachusetts and Rhode Island DSM programs using a workbook developed in 2005 by ICF International, Inc., updated with recommendations from the 2018 AESC Study. The company updates this workbook for each three-year planning cycle. The workbook calculates an annualized value of statewide avoided distribution capacity values from company-specific inputs that include historical and projected capital expenditures and peak loads, carrying charges, FERC Form 1 accounting data, and O&M costs.[290] National Grid uses a combination of historical and forecasted values within the workbook and accounts for operational energy efficiency, PV, and demand response programs. The load forecast used to determine the value of avoided distribution only includes projected PV and continued lifetime energy efficiency savings from prior plans and the current plan. The analysis does not include forecasted savings from future energy efficiency plans.

National Grid determines the percentage of the total distribution investments that are load-growth-related but not associated with new business. The resulting percentage is then applied to the distribution investment forecast. For avoided transmission costs, National Grid uses the 2018 AESC PTF of $94 per kW-year (in 2018 dollars) in both Massachusetts and Rhode Island. It does not account for non-PTF transmission costs.[291]

Table 111 summarizes the distribution methodology employed by National Grid, as well as recommendations for improvement.

[290] The Narragansett Electric Company d/b/a National Grid. Docket No. 5076 - 2021 Annual Plan. Attachment 4.

[291] The analysis in this section is based on National Grid MA and RI - 2018 Avoided T&D Workbooks,

Table 111. Assessment of National Grid's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology is mostly consistent with recommended methodologies in its consideration of load-growth-related T&D investments.	National Grid should account for non-PTF transmission costs.	-
Categories of investments considered	National Grid uses historical and forecasted T&D investments and assumes a percentage of that investment is related to load growth not associated with new business and is therefore avoidable with DSM.	It is not clear how the percentage of avoidable distribution investments were calculated since they are significantly lower than the overall distribution investments. It is unclear whether this estimate of the avoidable investments reflects all load-growth-related projects, including any capacity-related projects undertaken for non-load growth purposes such as reliability improvements.	National Grid should provide more transparency regarding the calculation of percentages representing load growth and new business. National Grid should use a more granular approach in the breakout of its T&D investments.
Load Forecast Methodologies	National Grid includes the impact of historical adoption of EE measures but does not include the impact of forecasted EE adoption.	National Grid should use a load forecast that includes future projected EE savings since the investment forecast assumes continued EE programs.	-
Detailed Considerations	National Grid uses a relatively short period of 11 years (5 years of historical data and 6 years of forecasted data) which may not be long enough to account for lumpiness associated with investments across the years. National Grid applies a carrying cost to investments when calculating avoided costs. National Grid includes both O&M and overhead costs in calculation of avoided costs.	National Grid should use a longer-term period for its analysis, in the range of 25-27 years. .	-

United Illuminating

United Illuminating developed estimates of the avoided T&D expenditures due to Conservation and Load Management (CLM) based on values from a 2017 Harbourfront Group study.[292] The 2017 Harbourfront study uses principles of marginal cost of service in order to develop a marginal cost of transmission based on coincident peak demand and a marginal cost of service based on non-coincident peak demand. The study calculated values for both historical years (2000–2016) and future years (2017–2026). The analysis assumed that non-coincident peak impacts resulted in substation and feeder demand reduction from all CLM measures, therefore resulting in the maximum estimate. The study also

[292] United Illuminating, Avoided Transmission and Distribution Cost Study 2000–2006.

assumed that the T&D costs that are avoided by the implementation of a CLM load reduction measure are the same as the marginal cost of T&D for adding or subtracting an increment of load. For the distribution system, the process involves identifying the T&D projects by separating out those that are load-growth-related from those that are not growth-related. For the transmission system, only projects that are undertaken to meet regional and national transmission and reliability standards were considered. The categories for the projects considered include transmission substation, transmission lines, distribution substations, and distribution feeders. The denominator for the marginal cost calculations is the added capacity or the load-serving capability of the capital project. The methodology used an economic carrying charge model and includes O&M expenses and overheads.

Table 112 summarizes the distribution methodology employed by United Illuminating, as well as recommendations for improvement.

Table 112. Assessment of UI's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology is broadly consistent with Avoided T&D methodologies in its consideration of load-growth-related T&D investments. The methodology is inconsistent with Avoided T&D methodologies in its consideration of load growth. The study is a marginal cost of service study more suited for application for purposes of cost allocation across different rate classes.	The study provides a marginal cost which uses a different methodology compared with the Avoided T&D cost methodologies suggested in this AESC. In the marginal cost development, the total investments identified for load growth projects were divided by the load-serving capability in developing the marginal costs. However, for an Avoided T&D study we recommend dividing instead by the growth in peak demand during the timeframe identified. The avoided costs were developed in context of the CLM program and its applicability to other programs should be evaluated and updated accordingly.	UI has used a weighting construct where 20% of their Avoided T&D value is combined with 80% of Eversource Avoided T&D value at the distribution level and transmission level. Further information would be beneficial regarding the accuracy and rationale of these assumptions.
Categories of investments considered	UI includes all growth- and capacity-related projects in calculation of avoided T&D costs. This includes capacity-related investments associated with projects that are undertaken for reliability improvements. UI considers both transmission and distribution investments at the substation and also considers feeder level distribution investments.	-	UI should clarify how it considers and includes investments that may be harder to characterize as solely load growth projects but may also contribute to alleviating load constraints.
Load Forecast Methodologies	In evaluating investments, UI includes the impact of historical adoption of CLM measures but does not include in forecasted CLM adoption. This methodology is accurate in	UI should include the impacts of electrification and state policy goals when identifying avoided T&D investments Although UI has developed a load forecast for identification of load	The load forecast methodology is not clear in terms of other energy efficiency measures included in the load forecast and the applicability of these values across other programs.

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
	quantifying the infrastructure costs that would be required without CLM provided that the investments and capital expenditure estimates also reflect growth without CLM included for consistency	growth related investments, for an Avoided T&D study we recommend dividing these investments by the growth in peak demand during the time frame identified as opposed to the load serving capacity of these projects identified.	
Detailed Considerations	Although there is no process for matching investments to load growth years, application of the relatively long period of 27 years (17 years of historical data and 10 years of forecasted data) accounts for some of the lumpiness associated with investments across the years. The analysis includes projects that could potentially be avoided or delayed by the implementation of CLM measures. UI has applied a carrying cost to investments when calculating avoided costs. UI has included both O&M and overhead costs in calculation of avoided costs.	-	-

Eversource (Connecticut, Massachusetts, and/or New Hampshire)

Eversource developed avoided or deferred T&D estimates using broadly similar methodologies across the three states it serves (Connecticut, Massachusetts, and New Hampshire) with some key differences in calculation of the percentage of avoidable or deferrable investments that could be considered in calculating the avoided costs. Its analysis in all three states considered both historical and forecasted investments on the T&D system.[293] For Massachusetts and New Hampshire, the methodology involved developing a value using the incremental investments and the incremental peak load growth over the same timeframe. In each of these states, Eversource assumed a certain percentage of the total T&D investments, respectively, were load-growth-related.

In the case of Connecticut, Eversource used a different approach. The methodology involved developing an additional regression analysis between historical investments and new customers to find the unavoidable investments associated with customer growth. These historical T&D investments that are related to customer growth are not considered avoidable/deferrable and are therefore removed from the analysis. Eversource used results of the regressions to evaluate the percentage of the T&D

[293] The analysis in this section is based on Eversource MA–2018 Avoided T&D Workbooks, Eversource CT–2018 Avoided T&D Workbooks and Eversource NH–2012 Avoided T&D Workbooks.

investments in Connecticut that are avoidable/deferrable, instead of the application of a percentage for Massachusetts and New Hampshire. Following this, Eversource conducted a regression analysis between incremental investments and peak load growth to assess the incremental investments associated with peak load growth in $/MW. The results of the two steps were combined to develop an annualized Avoided T&D cost.

Table 113 summarizes the distribution methodology employed by United Illuminating, as well as recommendations for improvement.

Table 113. Assessment of Eversource's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology used by Eversource is broadly consistent with Avoided T&D methodologies in its consideration of load-growth-related T&D investments and load growth. In the case of NH, the recommendations outlined are based on review of the workbooks used in developing the 2012 values. Eversource indicated that the methodology in subsequent updates has remained consistent.	Eversource does not currently estimate avoided/deferred T values for MA and NH. Synapse recommends calculating these values and updating at a consistent frequency.	Certain assumptions outlined below have not been supported with underlying sources and calculations. These should be provided in future updates. For CT, both United Illuminating and Eversource have indicated the use of a 20/80 weighted average based on the respective customer base. Calculations outlining the weighting process should be provided to ensure consistency between both entities.
Categories of investments considered	Eversource does address the inclusion of growth- and capacity-related projects in calculation of avoided T&D costs, although it is unclear if these have been accurately estimated.	In the case of NH and MA methodologies, it is not clear how the percentage of avoidable/deferrable investments were calculated and whether they are fully capturing all the avoidable load-growth-related investments. In the case of CT, the non-avoidable or deferrable T&D investments were derived using a top-down approach based on the number of customers added to the system. Eversource should consider looking at specific projects on a case-by-case basis that could be avoided or deferrable through load reductions.	To increase transparency and ensure consistency with AESC methodologies in calculation of avoidable/deferrable investments, Eversource should identify underlying sources that specify the methodology and calculations applied in identifying the historical and forecasted capital investments. This should include sources that outline the following: 1. The categories of investments considered (e.g., substation/feeder) and the inclusion of investments in the analysis that are incurred to address local load growth. 2. The analysis conducted in classification of investments as avoidable or deferrable including any calculations made to derive the avoidable/deferrable percentage estimates for both MA and NH Avoided D estimates.

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Load Forecast Assumptions	As of 2018, Eversource had not included the impacts of electrification in its forecast of T&D capital expenditures for the purpose of calculating avoided/deferred T&D costs. However, Eversource has indicated that future load and capital expenditure forecasting will include the impact of electrification.	-	The CT regression methodology for statewide T&D uses a presumed rate of load growth based on historical growth using data from the CT Siting Council. However, it is not clear if the load growth assumed for identifying the capital investments (typically done through T&D planning process) used this same estimate of load growth. These should be consistent. For MA and NH, due to limited data availability underlying the development of the load forecasts and capital expenditures, further details are required to ensure consistency with methodologies outlined in AESC. Eversource has indicated that the load forecasts used for T&D investment planning are consistent with those used for Avoided T&D estimates.
Detailed Considerations	Although there is no process for matching investments to load growth years, application of the relatively long period of data accounts for some of the lumpiness associated with investments across the years. Eversource has applied a carrying cost to investments when calculating avoided/ deferred costs. Eversource has included both O&M and overhead costs in calculation of avoided/deferred costs.	-	-

Unitil (Massachusetts and/or New Hampshire)

No specific information was provided.

Vermont

For statewide energy efficiency programs administered through Efficiency Vermont, the state uses the 2018 AESC PTF of $94/kW-year as a proxy for both the statewide average avoided cost of distribution and transmission combined.

This is due to the fact that within Vermont loads are expected to remain on a flat-to-declining trajectory for the foreseeable future and there have been no geographic locations where targeted energy efficiency could defer needed T&D investments since 2012. In addition, Vermont is facing generation constraints where substations are at thermal loading capacity, as described in more detail in the section below. This means that energy efficiency could create additional costs instead of avoided costs.

Similarly, the City of Burlington Electric Department (BED) does not assume any avoided distribution costs because the system is overbuilt. BED uses a value of $45 per kW for avoided transmission costs that was originally developed and approved in 2012.

Table 114 summarizes the distribution methodology employed in Vermont, as well as recommendations for improvement.

Table 114. Assessment of Vermont's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
Overall T&D Methodologies	Vermont uses only the PTF value, for the combination of PTF and non-PTF transmission, and distribution. The PTF methodology is consistent with the recommendations of this chapter, by default. The Burlington value does not reflect the region-wide nature of avoided PTF. Vermont does not derive any value for avoided non-PTF transmission or for distribution.	Vermont should apply the same avoided PTF transmission costs across the state. Vermont should consider tracking winter distribution peaks to identify whether electrification could cause the need for distribution upgrades and whether CLM could mitigate those costs.	Vermont should explicitly analyze and document the use of a $0 value for avoided non-PTF transmission and distribution costs, taking into account in-state differences in loads, distributed generation, and the impact of potential electrification.
Categories of investments considered	Because Vermont does not have a state-specific methodology for avoided T&D costs, it does not consider which investments are load-growth-related or whether to conduct analysis at the substation or feeder level.	-	-
Load Forecast Methodologies	VELCO Long Range Transmission Plan (LRTP) includes load forecasts that account for EE, PV, DR, and adjusts for the amount of efficiency embedded in the actual data along with the amount of efficiency expected to occur in the future.	-	-
Detailed Considerations	None	-	-

Maine

Efficiency Maine Trust (EMT) engaged Synapse as a subcontractor to ERS to develop statewide avoided T&D costs in dollars per kilowatt-year ($/kW-year). The methodology used in developing the values is consistent with methodology outlined in AESC. The analysis was dependent on data provided by Central Maine Power (CMP). Based on this limited data availability, Synapse has assumed that the avoided T&D cost for CMP will serve as a proxy for the statewide avoided T&D cost.[294] The developed avoided T&D

[294] Synapse did not have access to Versant data. While Synapse assumes the value for Versant will be nonzero, Synapse has no further information at this time and thus cannot include it in the statewide estimate.

value is based on the overall long-term ratio of T&D savings per kW of avoided growth using peak load forecasts and planned capital additions based on CMP data.

In calculated the distribution expenditures, CMP uses forecasted load at the level of the service center as part of Chapter 330 filings.[295] Synapse used the 50/50 load forecast from these filings. CMP provided Synapse with data for load-growth-related distribution capital expenditures. Some of the distribution capital expenditures were classified as both transmission and distribution; and in those cases a portion of such projects were allocated to transmission avoided cost calculations. In addition to transmission investments related to distribution projects, CMP also provided similar load-growth-related investments associated with the non-PTF transmission costs. In estimating the avoided non-PTF cost, Synapse assumed these needs to be driven by the ISO New England CELT forecast. Synapse also applied a real levelized carrying charge and an avoided O&M allowance based on data provided by CMP. Since Synapse had limited data regarding matching of the CMP's capital investment time periods with the load growth, Synapse presented a range of values based on different assumptions of time periods for both the capital investments and the load growth. EMT chose to use the mid-point value across this range.

10.4. Localized value of avoided T&D

In addition to crediting demand-side measures with value for avoiding T&D costs across a service territory, it may also be necessary to estimate the value of these measures in a location-specific context. One example includes the evaluation an NWA (or hybrid solution) as an alternative to a proposed or potential traditional infrastructure-based solution to a projected reliability issue. To comprehensively estimate the value that DERs, namely energy efficiency and demand response, provide to localized T&D systems, program administrators can develop and rely on localized T&D values. This section describes the approach developed in AESC Supplemental Study Part II: *Localized Transmission and Distribution Benefits Methodology* (Supplemental Study) to AESC 2018 at the request of a subset of the AESC 2018 Study Group. The section then surveys the landscape of location-specific avoided T&D methods and approaches in the region.[296]

Summary of supplemental study approach to localized T&D value

The key aspects of the Supplemental Study methodology are to:

1. Identify target areas and required load reduction
2. Determine benefits of targeted load reductions by identified target area

[295] Central Maine Power Company Annual Filing of Schedule of Transmission Line Rebuild or Relocation Projects, 35-A M.R.S.A. §3132(3); and Schedule of Minor Transmission Line Construction Projects, 35-A M.R.S.A. §3132 (3-A).

[296] Chang, M., J. Hall, D. Bhandari, P. Knight. May 1, 2020. *AESC Supplemental Study, Part II. Localized Transmission and Distribution Benefits Methodology.* Synapse Energy Economics for AESC Supplemental Study Group. Available at https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_II_Localized_TD.pdf

3. Calculate avoided cost ($/kW) based on the present value of deferred expenditures and the required load reduction

The following sections detail the three-step process for determining localized T&D values. We also describe current practices followed by participating utilities when evaluating NWAs. We recognize that the decision process for evaluating NWAs relative to traditional engineering solutions is a different process from quantifying the avoided T&D costs for DSM planning. These three steps will require program administrators to obtain information from their respective planning groups.

Step 1: Identify target areas and required load reduction

The localized T&D value requires the identification of target projects and required load reduction and duration in order to calculate the avoided cost. This first step of identifying target projects utilizes a utility's planning processes that identify system contingencies at peak load levels under normal and contingency operations.

Build on existing T&D planning

The first step in identifying target locations for evaluation is based on the results from utility's existing peak load forecasts at the transmission, sub-transmission, and distribution levels. The peak load forecasts should only account for program-related NWA components such as energy efficiency, PV, and demand response that are currently online and active.[297] The peak load forecasts should be conducted in accordance with the utility's T&D planning practices and regulatory requirements (typical forecasts of five to 10 years in the future for distribution planning and 10 years for transmission and sub-transmission planning). This process may involve developing resource-specific forecasts. Stakeholders may consider evaluating peak load forecasts to include any state/local/regional electrification goals mandated by current policy, if not required by statute.

Local transmission and sub-transmission: After estimating peak load levels, the next step is to establish the system planning criteria and performance objectives. The system planning criteria should be based on the utility's local transmission system planning guidelines and regulatory obligations. This would involve designing the system in accordance with any relevant standards and/or design practices. For example, in New England this may include planning criteria for the bulk electric system as defined by ISO New England, NERC standards, and Northeast Power Coordinating Council (NPCC). In addition, local standards may also apply (e.g., Maine's local "safe harbor" reliability standards). An example of system planning criteria would involve establishing the voltage operating ranges and loading criteria for system components under normal and contingency operation—such as normal, long-term emergency and short-term emergency limit ratings for each type of equipment, i.e., the loading at which the equipment can operate in normal and emergency situations.

[297] The load forecast should be the same for evaluating NWAs and traditional engineering solutions.

As part of the planning process, the planning group will run power flow simulations to identify the system contingencies and violations under varying system configurations. This may include understanding and applying the specific contingency standards (e.g., loss of element contingency such as N-0, N-1, N-1-1) that define the minimum infrastructure necessary to maintain security standards depending on the needs of the specific region. At a transmission level this is typically done through load flow analysis software such as Siemens' PSS/E.[298] The analysis should also estimate the required load reduction in order to mitigate the contingency.

Distribution system: The distribution system planning process will follow a similar process as transmission planning. Distribution planning requires projecting the peak load. This should include summer and winter peak load forecasts at a substation and circuit level. The peak load forecast should be done over a timeline that is consistent with the utility's distribution planning process. Depending on the utility, this forecast is typically done over a 10-year period.

The next step involves setting up the design criteria for planning of the distributions system. This includes establishing criteria for equipment loading, phase balancing, and ranges of system voltages, etc. Following this, a circuit analysis is conducted to identify where planning criteria and design threshold violations exist and where the system constraints are expected to occur. This is typically done using distribution system planning tools, e.g., Eaton's CYME software to assess the critical load levels, thermal, and voltage violations.[299] This step would also involve estimating the load reduction required to mitigate any identified contingencies.

Distribution system analysis should also include a process to identify potential areas where there may be reliability concerns that could be mitigated through NWA solutions.

Considerations

To prioritize areas for targeted NWAs, utilities currently consider various additional factors before assessing the potential for an NWA option. For example, utilities may establish minimum threshold criteria to meet when addressing a system contingency or considering an NWA as a resource option.

Utilities also currently consider the timeline required for building the NWA and whether this can be done in time to avoid the identified contingency or violation that it is meant to address based on local conditions. There are issues that may not be considered imminent or immediate concerns (e.g., issues that may have been accepted for many years) and should also be addressed accordingly. For example, contingencies that have sufficient lead time could be considered for NWA solutions whereas projects with imminent needs may not be suitable for NWAs.

[298] Siemens. Last accessed March 10, 2021. "PSS®E – High Performance Transmission Planning and Analysis Software." *new.siemens.com*. Available at https://new.siemens.com/global/en/products/energy/energy-automation-and-smart-grid/pss-software/pss-e.html.

[299] CYME. Last Accessed March 10, 2021. "CYME International" *Cyme.com.* Available at http://www.cyme.com/

In addition, the severity and nature of the overload (e.g., the contingency number) are a consideration for the NWA process. The conditions under which the constraint or planning violation has been identified should be factored in the analysis. This might include examining the degree to which the constraint is present in normal conditions or extreme conditions (such as hot weather). Utilities also consider the nature of the contingencies in terms of whether they are suitable applications for an NWA. In identifying target areas where there are concerns about backing up critical loads, these areas should not be automatically disqualified from NWA consideration—instead hybrid solutions between the NWA and a wires solution could also be considered and evaluated by the planning group.[300]

DSM planning and implementation

On the energy efficiency side, there is need to factor in the lead time for marketing, implementation, and verification of DSM under an NWA solution. As noted in the responses provided by the utilities and stated above, current NWA evaluation processes require a window of time prior to the need to start construction on T&D infrastructure. In their DSM planning processes, program administrators should also factor the amount of DSM that could be based on potential annual load reduction (percent) by class and projected overload, as well as estimates of distributed generation and storage capacity. Conversely, a conventional engineering solution will also take time, especially if it requires separate regulatory approval and other siting review.

Identifying expenditures avoidable by load reductions

This section describes an approach to identifying expenditures that are avoidable by load reductions. It incorporates ideas from existing methodologies used by utilities to identify regions suitable for NWAs.[301]

In identifying the expenditures avoidable by load reductions, first it is necessary to identify the magnitude, duration, and coincidence of the load reduction compared to the location and the timing of the traditional utility solution that would solve any system contingencies. Any constraints identified should be listed as such based on the first year that the constraint is identified. As discussed above, this should be identified through the system power flow analysis. At minimum, most utilities consider load growth and reliability as the expenditures that can be avoided by NWAs.[302] However, other projects may also have some suitability in replacing a wires solution.

If a project addresses both NWA-eligible constraints and also non-NWA-eligible constraints, the costs for such projects should be broken down between those that are NWA-eligible and non-NWA-eligible in estimating the avoided cost expenditures. The utility should clearly identify which investments are

[300] As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in methodology and applicability to more feeders.

[301] This methodology does not comment on the accessibility of detailed load, engineering, and cost data for feeders and components.

[302] While overall system load growth may be flat or declining for a given utility, there still may be individual feeders that are experiencing load growth.

considered as avoidable or deferrable through an NWA and the expenditures identified should be estimated in accordance with the utility capital investment planning guidelines. The expenditures should include operating expenses (e.g., reconfiguration) and capital investments and O&M associated with new facilities (net of any savings from retiring old equipment).

Utilities may establish a traditional engineering solution cost threshold before considering NWA solutions. Small projects that can be solved through traditional utility options (low-cost load transfers, etc.) may be less costly than procuring an NWA solution. Similarly, longer-term projects that do not have an imminent need and are above an established cost threshold may be more suitable projects for NWA consideration.

Identify type and period of required reduction

After identifying the expenditures that are avoidable by targeted load reductions, it is critical to identify the time at which the required load reduction is needed. This involves answering questions such as:

- Does the load reduction need to occur in a specific season?
- Does the load reduction need to occur in specific hours of the day?
- Over how many hours or days must the load reduction occur?

In addition, it is important to identify the number of years in which the reduction must occur. For example, if the goal is to defer an expenditure for three years, and the load is expected to exceed the system's capability for all three of those years, then an effective load reduction plan requires the load reduction to sustain for three years. Program administrators will need to coordinate with the utility's distribution planning group to ensure that localized demand reduction programs will meet the planning criteria as an appropriate solution.

Step 2: Determine benefits of targeted load reductions by identified target area

When calculating the avoided T&D costs, users should quantify the reduced present value of deferred expenditures. The annualized present value should reflect the utility's cost of capital, income taxes, property taxes, and insurance over the life of the equipment. To do so, one must first calculate the real carrying charge (RCC) that is expressed as a percentage. In general, the RCC equals the weighted average cost of capital (WACC), plus income tax, property tax, associated insurance, and O&M:[303]

$$RCC = WACC + Income\ Tax + Property\ Tax + Insurance + O\&M$$

[303] See Section 10.1 for a more detailed discussion of real carrying charge. The associated insurance and O&M costs may be expressed as a percentage of the deferred expenditure being analyzed.

The RCC should then be used to calculate the reduced present value of the avoided expenditures. For example, if the utility's RCC is 15 percent, then a $10 million investment would have an annualized expenditure of $1.5 million per year ($10 million x 15 percent).

There may be situations where a DSM load reduction defers a specific project by some period of time. For those situations and for the purposes of simplifying a more complex process, we recommend that the deferral value represents the traditional engineering expenditure reduced by the RCC and then discounted by the real discount rate.[304] In our illustrative example, if the RCC is 15 percent and the real discount rate is 3.37 percent, a 1-year deferral would have an avoided cost value of 85.5 percent (0.855 = 1 – [0.15 * (1 – 0.0337)]).

Step 3: Calculate avoided cost ($ per kW)

The next step is to calculate the avoided cost in terms of dollar per kilowatt (measured in $ per kW) for each identified target area.[305] To do so, program administrators must first compile:

1. The present value of the benefits from the deferral or avoidance of load-related expenditures identified in Step 2, above; and
2. The required load reduction, in kilowatts, required to achieve the deferral or avoidance of said expenditures.

Next, program administrators should divide the present value of the benefits from deferral or avoidance by the required load reduction to arrive at a localized avoided T&D value in dollars per kilowatt, by target area.

This value can serve as the conceptual average value for which to evaluate load reduction resources and technologies between the planning and energy efficiency groups. In other words, the average cost of the load reduction strategies used to achieve deferral or avoidance should be less than the calculated localized avoided T&D value, which is the value of the traditional engineering solution. If the average cost per kilowatt is greater than the localized avoided T&D value, then the avoidance or deferral portfolio costs more than the load-related expenditures that are targeted for deferral or avoidance. In these cases, alternative portfolios should be evaluated. If none are found to be cost-effective relative to the traditional engineering solution, the traditional engineering solution should be pursued.

Conceptually, it may be helpful to use the localized avoided T&D values as guidelines when compiling a portfolio to achieve the required load reduction. To the extent possible, program administrators should concentrate on achieving the required load reduction at lower costs per kilowatt than the avoided costs.

[304] For the purposes of this methodology, we do not address any probabilistic planning issues that may arise from the continued deferral or acceleration of specific distribution project due to changes in localized loads. A more detailed analysis would require the re-running of power flow analyses based on changed loads that may result in the determination of a different engineering solution.

[305] This methodology does not address issues regarding operational control or visibility associated with the T&D system.

However, specific resources may be less than or even greater than the average avoided cost, as long as the total portfolio cost is less than the localized avoided cost T&D value.

Evaluation of current utility methods

AESC 2021 includes a rubric, developed in parallel with the rubric used in Section 10.3: *Survey of utility avoided costs for non-PTF transmission and distribution* above, to survey current utility methods for quantifying the value of demand-side measures in avoiding or deferring geographically localized investments. The evaluation rubric for localized T&D methods is built on a similar structure to the Supplemental Study, but it is more flexible (and more focused on the raw data sources and approaches to analysis) to reflect different approaches to calculating these values and the relative lack of maturity of this aspect of avoided cost analysis.

The Synapse Team surveyed the utilities in the Study Group regarding their approaches to localized avoided T&D values. The following section describes our review of data and methods provided by participating utilities.

Below, we present summary tables of the evaluation rubric, applied to each utility that responded to the request for information about its methodology about the current locational valuation/NWA methodologies. Table 115 provides a general summary of methodologies related to identification of candidate locations for NWAs and the related load forecast methodologies. Table 116 provides specific criteria/thresholds for selection of a locations as an NWA. Table 117 and Table 118 provide a summary of specific design/engineering criteria that are applied at the T&D level.

Table 115. Summary of location-specific evaluation methodologies and load forecast processes

Criterion	Eversource	National Grid		United Illuminating	Vermont
	MA/NH/CT	MA	RI	CT	
Existence of a process to establish a location-specific value for avoided T&D costs in candidate locations for NWAs	Yes	Yes	Yes	No	Yes
Existence of a process to identify and/or select candidate locations for NWAs	Yes	Yes	Yes	No	Yes
Existence of a process for quantification of the required load reduction from these locations for calculation of the avoided costs	Yes	Yes	Yes	No	Yes
Whether the identification of these locations based on utility load forecasts	Yes	Yes	Yes	No	Yes
Granularity of load forecasts used by the utilities in identification of these locations.	Transmission and substation	System Level	System Level	N/A	Circuit Level
Inclusion of the following in the load forecasts:					
Operational EE	Yes	Yes	Yes	N/A	Yes
Operational PV	Yes	Yes	Yes	N/A	Yes
Operational DR	Only Eversource-sponsored DR	Yes	Yes	N/A	Yes
Inclusion of the following in the load forecasts:					
Projected EE	Yes	Yes	Yes	N/A	Yes
Projected PV	Yes	Yes	Yes	N/A	Yes
Projected DR	Only Eversource-sponsored DR	Yes	Yes	N/A	Yes
Inclusion of any electrification goals or mandates reflected in current policy	Yes	Yes	Yes	N/A	Yes

Notes: For Eversource, exact processes may vary across individual states between New Hampshire, Massachusetts, and Connecticut.

Table 116. Summary of processes for identifying locations that would benefit from load reductions

Criterion	Eversource	National Grid		United Illuminating	Vermont
	MA/NH/CT	MA	RI		
Whether the load growth forecasts are conducted in concert with the utility's T&D planning	Yes	Forecasts feed into assessment	Forecasts feed into assessment	N/A	Yes
Whether the utility applies a minimum threshold load criterion for qualification of a location in being considered for an NWA/used to calculate location-specific avoided costs	Yes	Yes	Yes	N/A	Yes
The existence of threshold load criteria used by the utility in identifying the target locations	Yes	Yes	Yes	N/A	Yes
Whether the utility develops a specific timeline for qualification of a location in being considered for an NWA/used to calculate location-specific avoided costs	Yes	Yes	Yes	N/A	Yes
Is there a timeline established for identification of a targeted location	Yes	Yes	Yes	N/A	Yes

Table 117. Summary of processes for identifying target locations that would benefit from load reductions at the transmission level

Criterion	Eversource	National Grid		United Illuminating	Vermont
		MA	RI		
Whether there is consistency with the utility's local transmission planning guidelines and regulatory obligations	Yes	Not applicable, screening occurs for sub transmission projects only	Not applicable, screening occurs for sub transmission projects only	No	Yes
Whether the targeted locations are identified through power flow simulations	Yes	Not applicable	Not applicable	No	Yes
Tools used for power flow modeling for this purpose	PSS/E, TARA	Not applicable	Not applicable	Not applicable	Not specified
How far into the future are these locations identified	10 years	Not applicable	Not applicable	Not applicable	10 years
What specific contingency standards are applied	NER , NPCC, ISO-NE Planning Eversource SYSPLAN-01 – Eversource Energy Transmission System Reliability Standards	Not applicable	Not applicable	Not applicable	ISO-NE, NERC, and other applicable reliability planning criteria
Are hybrid NWA solutions considered	Yes	Not applicable	Not applicable	Not applicable	Yes
Cost threshold for the traditional solution	Considered but details not specified	Not applicable	Not applicable	Not applicable	>$2.5M
Timeline criteria for the start of construction of the traditional solution	Considered but details not specified	Not applicable	Not applicable	Not applicable	≥2 years but <10 years
Load reduction and/or off-setting generation requirement	Considered but details not specified	Not applicable	Not applicable	Not applicable	1-3 yrs in future = 15% peak load 5 yrs in future = 20% peak load 10 yrs in future = 25% peak load

Table 118. Summary of processes for identifying target locations that would benefit from load reductions at the distribution level

Criterion	Eversource	National Grid		United Illuminating	Vermont
		MA	RI		
Whether the utility applies specific design criteria (for equipment loading, phase balancing, and ranges of system voltages, etc.) in identifying these locations?	Yes	Yes	Yes	No	Yes
The existing design criteria that are applied for this purpose	Equipment Loading limits, reliability targets, voltage limits, resiliency goals; Anti-islanding, flicker/transient limits, fault and short circuit, reverse flow	Yes	Yes	Not applicable	Yes
Consistency of the design criteria with utility distribution planning criteria that are applied in identifying traditional engineering solutions at the distribution level	Yes	Yes	Yes	Not applicable	Yes
Whether the targeted locations are identified through power flow simulations	Not initially	Yes, after initial assessment	Yes, after initial assessment	Not applicable	Yes
Tools used for power flow modeling for this purpose	Synergi, CYME, PSCAD	Not specified	Not specified	Not applicable	CYME
Are hybrid NWA solutions considered	Yes	Yes	Yes	Not applicable	Yes
Cost threshold for the traditional solution	>$1M	≥$500K	>$1M	Not applicable	>$2M or >$250K if relieving a delivery constraint
Timeline criteria for the start of construction of the traditional solution	2 years, less than 7 years from IRP filing date	18 months	30 months	Not applicable	≥2 years but <10 years
Load reduction and/or off-setting generation requirement	>30MW	Load reduction <20% of relevant peak load	Load reduction <20% of relevant peak load	Not applicable	25%

The following subsections present short descriptions of the methods used by each responding utility.

National Grid (Massachusetts and Rhode Island)

In both Massachusetts and Rhode Island, National Grid has a process to consider NWAs as part of its distribution planning process for distribution and subtransmission capital projects and system needs. National Grid identifies system needs as a result of studies, operational issues, process safety issues, occupational safety issues, regulatory requirements, and/or customer requests.[306] If the annual planning process identifies a system need, and that location passes the state-specific NWA screening criteria, then the project is shifted to an NWA analysis team for further review and analysis of the system need. The screening criteria for each state are shown in Table 119 below.

Table 119. National Grid NWA screening criteria

Criteria	Massachusetts	Rhode Island
Project Type Suitability	Project types include Load Relief and Reliability. Other types have minimal suitability and will be reviewed as suitability changes due to state policy or technological changes.	Project types include Load Relief and Reliability. The need is not based on asset condition. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline Suitability	Start of construction is at least 18 months in the future.	Start of construction is at least 30 months in the future.
Cost Suitability (Cost of Wires Solution)	Greater than or equal to $500K	Greater than $1M

Source: National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 2020.

The avoided cost is based on a NPV calculation based upon costs and benefits of the NWA solution, as well as the avoided costs of not implementing some (in the case of a hybrid solution) or all of the traditional wires solution.

National Grid also considers hybrid NWA opportunities during screening. These are an NWA solution, or a combination of NWA solutions, that addresses part of a specified system need with the rest of the system need addressed by a wires solution.

Table 120 summarizes the NWA methodology employed by National Grid, as well as recommendations for improvement.

[306] National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 2020.

Table 120. Assessment of National Grid's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	National Grid has a documented process and guidelines for screening NWAs.	-	Access to analysis and the NWA screening tool would increase transparency.
Transmission Specific NWA Criteria	-	-	-
Distribution Specific NWA Criteria	National Grid has a documented process which outlines the types of projects that can replace traditional solutions for NWA consideration. National Grid has criteria in place for the type of wires projects suitable for NWAs. These include criteria for type of project (load relief, reliability, non-asset condition), timing, and cost.	-	-

United Illuminating

Currently, United Illuminating does not have a regulatory-approved NWA process in place within the state of Connecticut.

Eversource (Connecticut, Massachusetts, and/or New Hampshire)

Eversource has a documented process and framework for identifying locations where DSM could be applied to meet a system need.[307] The need for an investment at a particular location is identified as part of the distribution planning process which accounts for all planned and existing system upgrades including the DERs. The process involves using an in-house screening tool that looks at how NWA approaches can replace traditional solutions. The tool provides a comparison of the revenue requirements between an NWA and deferring a traditional solution in assessing the locational value of an NWA.

For use in the screening tool, Eversource develops a portfolio of possible solutions and technologies which involves market research and gathering information from vendors and suppliers through RFIs (Request for Information). Possible solutions are evaluated based on longevity, dependability, and the specific need identified. These technologies are integrated to the screening tool which is designed to provide a preliminary identification of the NWA solution and whether such a solution will meet the reliability and performance needs of the system.

[307] Survey To Evaluate Program Administrators Avoided T&D methodologies. Responses received on November 16, 2020.

In screening for NWAs, Eversource considers various criteria for identifying locations and selecting technologies including the magnitude of the need (applying N-0 and N-1 criteria to assess the required capacity of the solution), duration of the need, the time of day of occurrence of the need, and the frequency at which the need occurs.

Distribution Planning Screening Criteria

Non-wires candidates include:[308]

- Projects that are capacity-related
- Projects that can be deferred via deployment of NWAs
- Hybrid Solutions: combined deployment of NWAs paired with a traditional system

Some specific suitability criteria and threshold that are excluded from NWA consideration are:

- Upgrades that impact old or failing assets, or those scheduled to be replaced
- Upgrades below a financial threshold (have a projected cost of at least $1 million)
- Upgrades with immediate needs (less than 2 years). Projects must have planned in-service date at least 3 years after the date of the Least Cost Integrated Resource Plan (LCIRP) filing.
- Projects require more than 30 MW of peak load relief within seven years of the latest LCIRP filing.

Transmission Planning Screening Criteria

Eversource is required to comply with the following reliability and planning standards when planning its transmission system:[309]

- NERC TPL-001-04 - Transmission System Standards
- NPCC Regional Reliability Reference Director #1—Design and Operation of the Bulk Power System
- ISO New England Planning Procedure 3 (PP3)—Reliability Standards for the New England Area Bulk Power Supply System

[308] New Hampshire Public Utility Commission. October 1, 2020. "Eversource Least Cost Integrated Resource Plan." *Puc.nh.gov.* Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-161/INITIAL%20FILING%20-%20PETITION/20-161_2020-10-01_EVERSOURCE_ATT_2020_LCIRP.PDF. Appendix D.

[309] Massachusetts Department of Public Utilities. Last accessed March 11, 2021. "Petitions of Western Massachusetts Electric Company d/b/a Eversource Energy Pursuant to G.L. c. 164 72 and G.L. c. 40A 3."Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9164120#page=54. Pg. 54-57

- Eversource SYSPLAN-01—Eversource Energy Transmission System Reliability Standards

Specific transmission suitability criteria for Non-Transmission Alternatives ("NTAs") also include response time to contingency conditions, minimum amount of operation time that resource is available for clearing of the contingency conditions, and land availability.[310]

Table 121 summarizes the NWA methodology employed by National Grid, as well as recommendations for improvement.

Table 121. Assessment of Eversource's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	Eversource appears to have a documented process and standardized framework for identifying locations where NWA could be applied to meet a system need on the distribution system.	For NWAs on the distribution system, access to the analysis (e.g., the NWA screening framework) would increase transparency.	-
Transmission Specific NWA Criteria	Targeted locations are identified through power flow simulations and reliability needs; the methodology for evaluation is consistent based on utility's local transmission planning guidelines and regulatory obligations. Eversource uses specific criteria and thresholds to exclude locations where NTAs are not suitable (minimum response time to contingency conditions, development time, land requirements). These may vary depending on the specific requirements of the project. Eversource focuses the NTA analysis on utility-scale resources; forecasted distributed generation, energy efficiency, and demand response are already used, where applicable, to reduce transmission system needs via inclusion in the ISO New England and Eversource load forecasts.	-	-
Distribution Specific NWA Criteria	Eversource has a documented process which outlines the types of projects that can replace traditional engineering solutions for NWA consideration; it also includes in a specific set of suitability criteria for qualification of a location that is suitable to NWA consideration including cost threshold, timeline and the quantity of load reduction required.	-	-

[310] "Non-Transmission Alternative" is the terminology used by Eversource in referring to NWA's at a transmission level.

Unitil (Massachusetts and New Hampshire)

Unitil has a documented process for identification of NWA opportunities. Per this process, Unitil applies design criteria for planning of the distribution and the transmission systems. At the distribution-system level, Unitil establishes a 90 percent planning threshold of seasonal rating for loads on substation transformers, stepdown transformers protective devices and other distribution circuit elements.[311] In addition, at the transmission and distribution levels, NWA projects are reviewed for any piece of major equipment that is expected to exceed 80 percent of its seasonal normal rating during the five-year study period and exceed 90 percent of its seasonal normal rating in year five of the study period during normal operating conditions.[312] The company indicated that the 80 percent threshold accounts for lead times needed to implement NWA solutions.[313] Unitil assumes a minimum of three years to receive, evaluate, and implement NWA proposals.[314] In addition, Unitil typically considers NWAs to be suitable in addressing loading and/or voltage constraints but not suitable for condition-based replacement projects.[315] Projects that address aging equipment may still be evaluated for NWAs, but this may not result in the issuance of an NWA RFP.

To estimate expenditures, Unitil has established a traditional engineering solution cost threshold before considering NWA solutions. Unitil has assessed that NWAs would generally not be evaluated if the recommended traditional option has an estimated cost of less than $250,000.[316]

Should a traditional engineering project meet the above criteria, Unitil will then issue an RFP for NWA solutions. Proposed NWAs are then reviewed through an evaluation process to score relative options for the company.

Vermont

Vermont's planning process are split into two phases.

<u>Transmission Level Process</u>

Every three years, the Vermont Electric Power Company (VELCO) publishes its LRTP. The LRTP analyzes the transmission system, identifies where the system does not meet design and reliability criteria, and describes the transmission alternatives to resolve the concerns.

Within the LRTP, VELCO applies the bulk transmission screening process originally adopted by the Vermont System Planning Committee (VSPC) and submitted to the Vermont Department of Public

[311] Unitil. Distribution Planning Guide. November 19, 2019. Page 8.

[312] Id. Page 8.

[313] Id. Section 4.3.

[314] Unitil. Project Evaluation Procedure, Page 3, July 2018.

[315] Unitil. Project Evaluation Procedure, Page 4, July 2018.

[316] Unitil. Project Evaluation Procedure, Page 3, July 2018.

Service (PSD) in Docket 7081. This screening process helps to determine if there is potential for the deficiency to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). For any transmission deficiency that screens, the PSD requires a Reliability Plan. In Vermont, Reliability Plans are synonymous with non-transmission alternatives (NTA).

Any affected distribution utility then drafts a project-specific action plan (PSAP) as required by the Docket 7081 Memorandum of Understanding. PSAPs describe a process for moving a deficiency from identification through to implementing a solution.

Sub-transmission and distribution process (geographic targeting)

Distribution utilities identify distribution-level constraints for consideration by VSPC and consider bulk/predominantly bulk transmission-level constraints once an LRTP is published, as described above.

Distribution constraints are typically identified in a utility's IRPs or at any time in intervening years by the utilities via the VSPC "Geotargeting" processes. As part of this process, the energy efficiency utility in consultation with the distribution utility and VELCO will determine the maximum achievable energy efficiency savings potential and costs. VSPC reviews the resulting recommendations for (1) areas needing new Reliability Plans, and (2) ending energy efficiency geographic targeting in any areas where analysis shows it is no longer cost-effective. The VSPC then it makes a recommendation to the PSD. A Reliability Plan is required for distribution constraints identified by distribution utilities in their IRPs or otherwise that screen in for full analysis using the Distributed Utility Planning (DUP) screening tool from Docket 6290.

There have not been any geographic targeting locations identified since 2012. According to the survey response as part of AESC 2021, Vermont noted that 15 percent of Green Mountain Power's substations are at thermal loading capacity due to backflow of distributed generation. This means that energy efficiency in some cases could lead to increased costs on the system. For example, if a substation is at capacity increased efficiency could result in the dumping of renewable generation or require increased investments to ensure reliability. While this issue is currently limited to a small number of hours, it is anticipated to become exacerbated over the next decade as more renewable energy comes online to meet Vermont's clean energy goals.

Table 122 summarizes the NWA methodology employed by Vermont, as well as recommendations for improvement.

Table 122. Assessment of Vermont's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	Vermont has a robust framework and criteria for identifying transmission, sub-transmission, and distribution-level NWAs.	-	-
Transmission Specific NWA Criteria	Targeted locations are identified through VELCO LRTP using power flow simulations and reliability. The methodology for evaluation is consistent with transmission planning guidelines and regulatory obligations. Vermont has criteria thresholds for excluding locations where NWAs are not suitable (regarding asset condition, cost thresholds, and timeline).	-	-
Distribution Specific NWA Criteria	Vermont has a screening tool specific to distribution-level NWAs. The screening tool contains criteria for excluding locations where NWAs are not suitable (emergency or failing asset, cost and timing thresholds).	-	-

Maine

In June 2019, the Maine Legislature enacted *An Act to Reduce Electricity Costs through Non- wires Alternatives*.[317] This Act identified a non-wires coordinator position in the Office of Public Advocate. Based on this, the criteria and process for identification of NWAs within the state of Maine is currently underway.

Consideration of location-specific costs and benefits in generation-constrained areas

Electrical systems have historically been designed for one-way flow of electrical power from central generators to distributed loads. However, the increased adoption of distributed generation resources is causing changes in that paradigm. This is particularly true in areas where generation can now approach or exceed load, but where the grid was designed and built to serve the load. Such locations have begun

[317] Maine Legislature, An Act to Reduce Electricity Costs through Non-wires Alternatives. http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=HP0855&item=3&snum=129.

to appear in New England, including several locations in Vermont at both the transmission[318] and distribution[319] levels.

As part of its interconnection process, each generator is generally asked to pay for incremental changes in the grid that are required in order to interconnect safely and without impacting reliable service to customers. However, changes in load are not generally subject to the same type of analysis even though they could change the relationship between load and generation on a given circuit or other grid segment. Changes in end-use load that result in increased load during times when the distributed generation is producing could have the effect of mitigating reliability concerns, reducing strain on transformers or other grid hardware, or allowing more generation to interconnect (thereby potentially advancing state energy policies). On the other hand, changes in end-use load that result in decreased load during times when the distributed generation is producing could exacerbate reliability concerns, increase strain on grid hardware, or cause curtailment of generation.

Many of the general principles and considerations of localized avoided T&D costs could apply in the context of generation-constrained areas, just as they apply in the context of load-constrained areas. For example, the analysis would need to identify the specific costs corresponding to changes in the grid configuration that could be avoided or created by a change in end-use energy demand. With sufficient information regarding costs and the impacts on relevant peak loads (or exports), it would be possible to calculate a location-specific avoided T&D cost value for interventions that increase load, and a location-specific cost caused for interventions that decrease load, using the same approach to location-specific avoided T&D costs described earlier in this section.

The temporal and locational characteristics of the need should be carefully described. For example, if the issue of concern is created on sunny days during shoulder seasons when loads are otherwise low, then changes in an end-use that operates only during the coldest days of winter would have no impact. The dynamic aspects of active demand management and load control measures that can respond to grid conditions (such as different behavior on sunny and cloudy days) should be accounted for. This would entail accounting for the contribution during peak and off-peak hours rather than only accounting for the average behavior across all hours. Hourly load profiles and load shapes for measures, including

[318] See, for example, the discussion in Vermont Public Service Department. 2019. Vermont public Service Department. January 15, 2019. "Identifying and Addressing Electric Generation Constraints in Vermont." Vermont.gov. Available at https://publicservice.vermont.gov/sites/dps/files/documents/2019%20Act%20139%20Generation%20Constraints%20Report%20final.pdf.

[319] See Green Mountain Power. 2019. *Vergennes Generation Constrained Area* available at https://www.vermontspc.com/library/document/download/6603/VSPC%20Vergennes%20%285-21-1019%29%20%28002%29.pdf and Green Mountain Power. 2020. *Substation Generation Constraints: Hypothetical Constraint Review* available at https://www.vermontspc.com/library/document/download/7092/GMP_Hypothetical%20Constraint%20Review.pdf for discussions of issues in the vicinity of Vergennes, Vermont. Other presentations and notes from the Generation Constraints Committee of the Vermont System Planning Committee can be found here: https://www.vermontspc.com/vspc-at-work/subcommittees.

correlations with weather conditions where relevant, may be required to fully evaluate the impacts of traditional efficiency or electrification measures.

10.5. Avoided natural gas T&D costs

See Section 2.4: *Avoided natural gas cost methodology* for more information on the assumptions used in AESC with respect to natural gas transmission and distribution.

11. VALUE OF IMPROVED RELIABILITY

The reduction in electric loads can improve reliability in several ways. First, it can increase installed generation reserves and thus reduce the probability of inadequate supply under variable loads and generation outages. Second, the reduction decreases the thermal wear and tear on transformers and conductors and thereby reduce failures. Thirdly, it reduces the probability of overloads on T&D equipment to reduce faults. The last of these three categories overlaps with avoided T&D costs, since the ISO and utilities usually expand capacity to avoid system overloads. To the extent that lower loads result in less T&D capacity, the reduced capacity will tend to offset the benefits of lower loads. We have not been able to determine a method for accounting for that overlap. Hence, we do not estimate any value for reduced acute overloads on the delivery system, even though there are undoubtedly some situations in which lower load would allow the system to survive some equipment failures, without deferring capacity additions.

In AESC 2021, we find a default average VoLL value of $73 per kWh. This value is almost 3 times as large as the value derived in AESC 2018 ($26 per kWh in 2021 dollars). The change in the VoLL component is a result of updated information on VoLLs. This VoLL is then applied to the calculation of reliability benefits resulting from dynamics in New England's FCM to estimate cleared and uncleared benefits linked to improving generation reliability. In AESC 2021, we find 15-year levelized values of $0.47 per kW-year for cleared benefits and $8.45 per kW-year for uncleared benefits. These are 32 percent lower and 21 percent higher, respectively, than the same values estimated in AESC 2018, after adjusting for inflation. For cleared reliability, despite a higher VoLL, overall benefits are lower as a result of flatter supply curve assumptions for the capacity market. Changes to the capacity market have less of an impact on uncleared resources, which exist outside the capacity market. As a result, an increase in the VoLL produces an increase in the uncleared reliability value.

New in AESC 2021, we provide an estimated benefit for T&D reliability, based on data for National Grid Massachusetts. This section is provided as an example calculation of how different utilities could calculate their own T&D reliability benefit. This value would likely differ for each jurisdiction.

The following sections describe VoLL, the application of that value to generation reliability, and the potential for extension to distribution reliability.

11.1. Calculating value of lost load

In AESC 2018, we identified the most recent and detailed analysis of the VoLL to be that in the Lawrence Berkeley National Laboratory's (LBNL) 2015 study on *Updated Value of Service Reliability Estimated for Electric Utility Customers in the United States.* LBNL estimated costs of unserved energy for outages of one to four hours (typical of generation capacity shortfalls) on the order of $3 per kWh for residential,

$17 per kWh for large commercial and industrial (C&I), and $250 per kWh for small C&I—with shorter outages imposing higher costs per kWh (see Table 123).[320]

Table 123. Average cost per unserved kWh (2021 $ per kWh)

	Duration of Outage					
	Momentary	30 minutes	1 hour	4 hours	8 hours	16 hours
Medium & Large C&I	$218	$43	$25	$14	$15	$15
Small C&I	$2,575	$542	$337	$245	$305	$295
Residential	$35	$7	$4	$2	$2	$1

Source: LBNL. (2015). "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf. Table 1
Notes: Values originally reported in 2013 dollars have been converted into 2021 dollars.

Focusing just on the outages of one to four hours (typical of generation capacity shortfalls), these costs translate into values of on the order of $19 per kWh for medium and large C&I, $291 per kWh for small C&I, and $3 per kWh for residential.

For AESC 2021, we reviewed the recent literature on VoLL, looking for values more relevant to New England. We did not find any new domestic studies to add to our literature review conducted for AESC 2018.

In our updated literature review, we identified a relevant 2018 study from Europe written by Cambridge Economic Policy Associates: "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe."[321] The 2018 report estimated the VoLL for each European Union country, for residential customers and 13 types of non-residential customers (nine industrial sectors, construction, transportation, services and a combination of agriculture, forestry, and fishing). The values for some sectors vary strongly with the wealth of the country. To increase comparability with New England, we looked at the estimates for the 19 countries with gross domestic product (GDP) of at least half of New

[320] LBNL. (2015). "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.

[321] Cambridge Economic Policy Associates Ltd. "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe." July 2018. Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf.

England's $77,574 average GDP per capita.[322] Table 124 shows the estimates for each of those countries and the simple average.[323]

Table 124. Residential VoLL in high-income European countries GDP per capita values

Country	Annual average VoLL for all sectors *2021 $/kWh*	Annual average VoLL for service sector *2021 $/kWh*	GDP per Capita *2021 $/person*
Austria	$12.09	$14.00	$60,631
Belgium	$12.89	$11.76	$56,041
Cyprus	$8.31	$6.24	$42,672
Czech Republic	$4.74	$5.46	$44,094
Denmark	$21.11	$15.56	$62,375
Estonia	$6.95	$3.84	$39,847
Finland	$7.11	$6.52	$52,517
France	$9.29	$9.60	$49,836
Germany	$16.66	$11.48	$58,183
Ireland	$15.46	$18.75	$93,644
Italy	$15.22	$10.51	$45,852
Lithuania	$6.20	$6.00	$40,175
Luxembourg	$18.15	$17.91	$123,535
Malta	$8.56	$6.01	$47,515
Netherlands	$30.79	$11.96	$61,438
Slovenia	$5.80	$6.25	$42,180
Spain	$10.58	$8.91	$44,138
Sweden	$7.41	$9.41	$57,450
United Kingdom	$21.34	$17.52	$50,348
Average	**$12.56**	**$10.40**	**$56,446**

Note: All monetary units have been converted into 2021 dollars.

The $12.56 per kWh average is much higher than the $3 per kWh LBNL estimate for residential customers. Since the average GDP per capita for these countries is $56,446, or 73 percent of the New England GDP/capita, the VoLL for New England households is likely to be higher. For the four highest-income countries, with an average GDP/capita similar to New England's, the average VoLL estimate is 45 percent higher, or $21.38 per kWh. We note that most of the factors that would influence VoLL (cold winters, hot summers, high reliance on computers and related equipment) are at least as powerful for New England as the average European country.

[322] GDP per captia data for New England calculated using U.S. Bureau of Economic Analysis and U.S. Census data (BEA. Last accessed March 3, 2021. "GDP and Personal Income." Bea.gov. Available at https://apps.bea.gov/iTable/iTable.cfm?reqid=70&step=1&acrdn=1) and (U.S. Census Bureau. 2019. "State Population Totals and Components of Change." Census.gov. Available at https://www.census.gov/data/tables/time-series/demo/popest/2010s-state-total.html)

Other than Luxembourg and Ireland, European national GDP per capita is uniformly lower than New England's.

[323] The VoLLs are from Table G.1 of the Cambridge Economic Policy Associates study. The per capita GDP values are from The World Bank. Last accessed March 11, 2021. "GDP Per Capita, PPP – European Union." *Data.worldbank.org.* Available at https://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD?locations=EU.

The Cambridge Economic Policy Associates study estimates of VoLL for non-residential customers do not map clearly onto the small-C&I and large-C&I categories of the LBNL study. Nor do the industrial sectors in the study map well onto important New England industries, such as biotech. The value for the services sector, which would include a large portion of major New England C&I customers (banking, real estate, data services) is about half of the LBNL estimate for large-C&I customers, at $10.40 per kWh for the nineteen countries. The result is more similar for the European countries most similar to New England in terms of GDP per capita, at $16.04 per kWh.

For AESC 2021, we average the findings from the LBNL and Cambridge Economic Policy Associates studies together for each category of customer. Then, using share-of-sales data from EIA's form 861, we calculate a weighted average (see Table 125). The resulting VoLL is $73 per kWh.

Table 125. Calculation of VoLL

	LBNL *2021 $/kWh*	CEPA Ltd. *2021 $/kWh*	Final *2021 $/kWh*	Sales shares *%*
Residential	$2.80	$12.56	$7.68	40%
Small C&I	$290.87	$10.40	$150.64	45%
Large C&I	$19.36	$10.40	$14.88	14%
Weighted Average VoLL			**$73**	

Notes: Sales shares are estimated using 2019 data from EIA Form 861. We assign "commercial" sales from EIA for Small C&I and "industrial" sales to large C&I.

11.2. Value of reliability: Generation component

We observe that reducing loads can improve generation reliability in three 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 following sections describe how we calculated this component for cleared measures and uncleared measures.

Calculating cleared reliability

In order to calculate cleared reliability benefits, we first assemble several input parameters. First, ISO New England annually publishes marginal reliability index (MRI) curves, which estimate the expected energy lost per MW of additional supply as the reserve margin rises. In AESC 2021, we examine the slope of the MRI curve at each auction's clearing price. The resulting value can be thought of as the estimated change in MWh of reliability benefits per megawatt of reserve. Values calculated in FCA 12 through 15 utilize the MRI curve published for each auction, while all auctions that take place after FCA 15 utilize the MRI curve published for FCA 15. Table 126 displays the estimated change in MWh of reliability benefits per megawatt of reserve, and how it varies with the capacity market clearing price.

Table 126. Change in MWh of reliability benefits per megawatt of reserve for Counterfactual #1 in rest-of-pool region

		Clearing price *2021 $/kW-month*	Δ MWh LOEE per MW *MWh / MW*
FCA 12	2021	$4.77	0.329
FCA 13	2022	$3.96	0.273
FCA 14	2023	$2.47	0.170
FCA 15	2024	$2.75	0.189
FCA 16	2025	$2.72	0.187
FCA 17	2026	$2.88	0.199
FCA 18	2027	$3.11	0.214
FCA 19	2028	$3.30	0.227
FCA 20	2029	$3.59	0.248
FCA 21	2030	$3.42	0.237
FCA 22	2031	$3.67	0.253
FCA 23	2032	$3.90	0.268
FCA 24	2033	$3.86	0.265
FCA 25	2034	$4.67	0.323
FCA 26	2035	$3.66	0.253

Note: Values for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Due to the slopes of the supply and demand curves, bidding an additional MW into the FCA at $0 per kW-month price shifts the supply curve to the right. This shifts out some smaller amount of capacity that would otherwise have cleared, and it results in the amount of cleared supply increasing by only a fraction of the additional supply. That fraction is small when the clearing price is set at a shallow part of the supply curve, and it increases if the clearing price is set at a steeper part of the supply curve (see Table 127). This value is calculated by dividing the supply price shift by the difference between the supply price shift and the slope of the demand curve at the demand value implied by the clearing price.

Table 127. Net increase in cleared supply for Counterfactual #1 in rest-of-pool region

		Clearing price	Net increase in cleared supply
		2021 $/kW-month	*%*
FCA 12	2021	$4.77	8%
FCA 13	2022	$3.96	7%
FCA 14	2023	$2.47	16%
FCA 15	2024	$2.75	17%
FCA 16	2025	$2.72	17%
FCA 17	2026	$2.88	16%
FCA 18	2027	$3.11	20%
FCA 19	2028	$3.30	20%
FCA 20	2029	$3.59	19%
FCA 21	2030	$3.42	20%
FCA 22	2031	$3.67	19%
FCA 23	2032	$3.90	18%
FCA 24	2033	$3.86	18%
FCA 25	2034	$4.67	79%
FCA 26	2035	$3.66	19%

Note: Values for other counterfactuals and regions can be found in the AESC 2021 User Interface.

The final component used to calculate cleared reliability benefits is a decay effect. Over time, customers will respond to lower prices by using somewhat more energy, including at the peak. In addition, lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources, which will result in these resources being removed from the supply curve. Further, some new proposed resources that have not cleared for several auctions may be withdrawn (if, for example, contracts and approvals expire, raising the cost of offering the resource into future auctions). The decay schedule used for cleared reliability is the same as the one used for cleared capacity DRIPE (see Table 89, above).

Finally, we calculate the cleared reliability benefit 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, as calculated above.[324] Table 128 describes the overall benefit for a measure installed in 2021. We note that these values are very small compared to the estimated avoided costs in many other categories.

[324] Note that the *AESC 2021 User Interface* allows users to specify their own VoLL, if they so choose.

Table 128. Estimated cleared reliability benefits for Counterfactual #1 in rest-of-pool region for measures installed in 2021, assuming a VoLL of $73 per kWh

		Δ MWh LOEE per MW	Net Increase in Cleared supply	Decay Schedule	Cleared reliability benefits
		MWh / MW	*%*	*%*	*2021 $/kW-month*
FCA 12	2021	0.329	8%	100%	$1.92
FCA 13	2022	0.273	7%	83%	$1.22
FCA 14	2023	0.170	16%	67%	$1.29
FCA 15	2024	0.189	17%	50%	$1.15
FCA 16	2025	0.187	17%	33%	$0.77
FCA 17	2026	0.199	16%	17%	$0.39
FCA 18	2027	0.214	20%	0%	$0.00
FCA 19	2028	0.227	20%	0%	$0.00
FCA 20	2029	0.248	19%	0%	$0.00
FCA 21	2030	0.237	20%	0%	$0.00
FCA 22	2031	0.253	19%	0%	$0.00
FCA 23	2032	0.268	18%	0%	$0.00
FCA 24	2033	0.265	18%	0%	$0.00
FCA 25	2034	0.323	79%	0%	$0.00
FCA 26	2035	0.253	19%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2021 User Interface. The "decay schedule" series is identical for measures installed in later years, except shifted by the relevant number of years.

Calculating uncleared reliability

Like cleared reliability, the calculation of uncleared reliability benefits requires the assembly of several input parameters.

The first is the estimated change in MWh of reliability benefits per megawatt of reserve. This parameter is the same as is used in the calculation of cleared reliability benefits (see Table 126, above).

Second, uncleared reliability benefits are grossed up to account for the impact of the reserve margin. As with uncleared capacity and uncleared capacity DRIPE, because uncleared reliability benefits accrue outside of the FCM, they are effectively "counted" in the demand side of the capacity auction. See Table 44, above, and surrounding text for more information on this effect.

Third, we assume that reliability has a phased impact on the load forecast. In contrast to uncleared capacity and uncleared capacity DRIPE, reliability is not dependent on the operation of ISO New England's load forecasting and capacity market. As soon as load is reduced, the reserve margin increases (since the uncleared capacity does not initially reduce capacity procurement) and reliability is improved. Hedging of capacity supply, either short- or long-term, does not reduce the reliability effect, as it does capacity DRIPE. Thus, the reliability improvement starts at 100 percent in the first year and persists until the load reduction affects the FCA. Unlike other uncleared avoided cost categories, which operate through the effect on the econometric load forecast, the reliability improvement from any given measure does not rise with the number of years it has been in place, but only by the increase in reserves for the year.[325]

Fourth, uncleared reliability benefits will gradually decay over time, as the load reduction is reflected in the load forecast, reducing the amount of capacity that ISO New England acquires. Eventually, the load reduction would be fully captured in the load forecast, and the reliability benefit would be extinguished. The decay of the reliability benefit of uncleared resources starts later and is more gradual than the one used for cleared resources, because the market does not react to the resources and reduce procurement until it is picked up in the load forecast.

Finally, we calculate the uncleared reliability benefit by calculating 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.[326] Table 129 describes the overall benefit for a measure installed in 2021. Generally speaking, reliability effects of uncleared resources are greater than those of cleared resources. This is because the cleared resources immediately displace other resources, resulting in a smaller net gain in reliability. Uncleared resources increase reliability more than cleared resources do, for the same reason that uncleared resources have no immediate effect on capacity bills or prices—unclear resources are invisible to the capacity market.

Table 129. Estimated uncleared reliability benefits for Counterfactual #1 in rest-of-pool region for measures installed in 2021, assuming a VoLL of $73 per kWh

		Δ MWh LOEE per MW *MWh / MW*	Reserve Margin *%*	Load Forecast Effect *%*	Decay Schedule *%*	Uncleared reliability benefits *2021 $/kW-month*
FCA 12	2021	0.329	14%	100%	100%	$27.29
FCA 13	2022	0.273	14%	100%	100%	$22.82
FCA 14	2023	0.170	15%	100%	100%	$14.29
FCA 15	2024	0.189	15%	100%	100%	$15.79
FCA 16	2025	0.187	16%	100%	100%	$15.82
FCA 17	2026	0.199	13%	70%	100%	$11.45
FCA 18	2027	0.214	14%	50%	95%	$8.42
FCA 19	2028	0.227	14%	30%	87%	$4.94
FCA 20	2029	0.248	14%	10%	75%	$1.55
FCA 21	2030	0.237	14%	0%	60%	$0.00
FCA 22	2031	0.253	14%	0%	43%	$0.00
FCA 23	2032	0.268	14%	0%	27%	$0.00
FCA 24	2033	0.265	14%	0%	0%	$0.00
FCA 25	2034	0.323	14%	0%	0%	$0.00
FCA 26	2035	0.253	14%	0%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2021 User Interface. The "decay schedule" series is identical for measures installed in later years, except shifted by the relevant number of years.

325 In this regard, the reliability benefit of unclear capacity operates more like avoided energy or cleared capacity than like uncleared capacity or capacity DRIPE.

326 Note that the *AESC 2021 User Interface* allows users to specify their own VoLL, if they so choose.

Important caveats for applying reliability values

Unlike other uncleared avoided cost categories (e.g., uncleared capacity, uncleared capacity DRIPE) uncleared reliability avoided costs are summed over the time period that a measure is active. This is similar to the approach used to sum avoided costs for most categories.

Unlike other uncleared avoided cost categories, users should not apply a scaling factor (like the kind described in Appendix K: *Scaling Factor for Uncleared Resources*). The scaling factor reflects a demand measure's effect on the load forecast, which is a function of the number of daily peaks (the inputs to the ISO New England demand forecast regression) that are reduced by the measure. Because changes in reliability do not impact the load forecast, the scaling factor should not be used to adjust uncleared reliability benefits.

Other considerations: reliability impact on non-summer peak hours

Measures increase generation reliability to the extent that they reduce load at hours that would contribute to ISO New England's estimate of loss-of-energy expectation (LOEE). An efficiency measure that clears as 1 kW of supply in the capacity auction may provide more or less load reduction during the highest LOEE hours. We note that these hours may not necessarily coincide with ISO New England's definition of on-peak hours for on-peak resources (weekday hours ending 14-17 from June through August and hours ending 18 and 19 in December and January) or seasonal resources (hours in June through August, December, and January with load greater than 90 percent of the seasonal 50/50 peak), especially as solar generation reduces LOEE in sunny summer hours.

In setting the demand curve for each capacity auction (both the FCAs and the annual reconfiguration auctions), ISO New England derives various measures of generation risk, including loss-of-load expectation (LOLE), which is a measure of the fraction of time intervals for which supply might be inadequate, and the LOEE, the amount of energy that would not be served on average. ISO New England provided its risk results from the second annual reconfiguration auction for the 2022–2023 capacity compliance period (the period covered by FCA13), as shown in Table 130. All months other than the summer had zero risk in this analysis.

Table 130 suggests that only the reductions in the highest-net-load hours of the summer are likely to have any effect on reliability, at least in the near term.[327] That may change as electrification increases winter loads and storage flattens the effective peaks.

[327] See https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_I_Winter_Peak.pdf for more discussion on this.

Table 130. Monthly distribution of risk prices for capacity commitment period 2022–23, annual reconfiguration auction #2

	June	July	August	Annual
LOLE (days)	0.00066	0.02059	0.07868	0.09994
LOLE (hours)	0.00194	0.11075	0.43035	0.54303
LOEE (MWh)	0.953	119.184	524.418	645.153
Percentage by month				
LOLE (days)	0.7%	20.6%	78.7%	
LOLE (hours)	0.4%	20.4%	79.2%	
LOEE (MWh)	0.1%	18.5%	81.3%	

11.3. Value of reliability: T&D component

New to AESC 2021, we provide an example methodology of how utilities might calculate a value of reliability associated with T&D.

Theory

Reducing loads can also reduce overloads and violations of T&D planning standards, by:

- Leaving additional capacity across this system to accommodate flows from facilities or equipment that are forced out of service by non-load-related problems,
- Reducing overloads under extreme weather conditions, and
- Reducing wear on lines and transformers from the cumulative effects of many hours with high loads.[328]

The aging of transformers (both at substations and along primary feeders) primarily results from the breakdown of insulation due to heating. That deterioration can be driven by:

- Short periods of very high load levels: transformers typically can be operated at over 150 percent of their rated capacity for an hour or two, if they start cool.
- Long periods (such as many hours or days) of lower but still high loads, which heat up the insulation.
- Even more so, very high load levels following a long period of high loads.

Similar considerations also apply to underground T&D lines that are insulated in the ground. These underground lines and their insulation also heat up due to long periods of high loads.

[328] Other causes (tree, weather, animal contact, etc.) of outages are not load-related and are thus outside the scope of this analysis.

Some overhead lines are subject to a different set of load-related failure modes. Generally, the surrounding air cools the lines and reduces the effect of heat buildup at moderate load levels. However when lines are loaded near their thermal ratings, this can lead to deterioration of insulation (if they are insulated). High loads can also stretch and weaken the metal conductor, and reduce line clearance from the ground or other objects below the line. Stretched lines are more vulnerable to breakage from other stresses, such as wind load.[329]

We examined utility reports on distribution outages to attempt to estimate the amount of load lost due to potentially load-related equipment failure, as opposed to events such as tree, vehicle, or animal contact.

The value of increased T&D reliability is complementary, not duplicative, of the avoided T&D costs. Reducing loads (or avoiding rising loads) will tend to increase reliability even when the T&D system does not change. By contrast, the reliability for a T&D element (e.g., distribution substation, feeder, line transformer, secondary lines) is not likely to improve for T&D equipment that is avoided by a load reduction.[330]

Example calculation

For the purposes of AESC 2021, we reviewed the 2019 outages in National Grid Massachusetts "Unplanned Significant Outage Report" in DPU 20-SQ-11, which included about 4,700,000 customer-hours of outage. Those hours were about 65 percent due to trees, with failed equipment accounting for over 14 percent (over 682,000 customer-hours), and other categories (lightning, animals, and other miscellaneous) totaling about 20 percent. The outages that National Grid listed as due to failed equipment included some that were clearly not due to electrical failure, such as broken poles, lightning arresters, and brackets; many categories that might conceivably be related to heavy loading (e.g., "tired fuses," fires, and failed switches, breakers, and reclosers); and a few likely to be load-related (failed transformers, underground cables, and splices). That last group of outages amounted to about 176,000 customer-hours, about 4 percent of the total outage hours. We note that some portion of these outages may be associated with deferred maintenance or defective parts, and may not ultimately be avoidable through load reductions.

Exhibit NG-HSG-3A to National Grid's filing in DPU 18-150 provides customer number and sales by class. The average non-streetlighting customer uses about 15 MWh annually, but many of the largest customers are served at primary or even transmission voltage. The customers served at secondary voltage would be exposed to more outages than customers served at primary voltage, and the transmission-level customers would not be affected by any of these distribution outages. Counting only

[329] Many overhead lines are self-supporting and thus vulnerable to stretching and physical stress. Line supported by much stronger steel messenger wire are less sensitive to the mechanical stresses.

[330] Logically, similar considerations would apply to the reliability of natural gas supply by LDCs, but that subject is beyond the scope of AESC 2021.

50 percent of the sales at primary and none of the sales at transmission, the average usage falls to 14 MWh per customer annually, or about 1.6 kWh per customer-hour.

Multiplying together the number of customer-hours related to load-related outages (about 176,000), 1.6 kWh per customer-hour and $73 per kWh VoLL yields a total annual cost of the potentially load-related outages of about $21 million annually. Dividing by total distribution sales of about 19.8 TWh, this resulting per-MWh cost is $1.04 per MWh. The load-related failures in 2019 were presumably due to accumulated damage over decades of service, but the energy delivered in 2019 will contribute to failures that occur in 2019 as well as future years. Hence, it appears reasonable to estimate the load-related costs of lost distribution reliability in future years to be similar to the cost derived from 2019 data. The distribution reliability cost may vary by time period, with potentially higher costs in peak hours than off-peak hours and higher costs in summer months than the rest of the year.[331]

The methodology of this analysis could be applied for other investor-owned utilities that file similar data, and for additional years. Similar data may be available from electric utilities in other states. We recommend that utilities or program administrators examine data local to their own jurisdictions and evaluate their own estimates of T&D reliability benefits.

[331] High winter loads may also contribute to the aging of transformers, but lower air temperatures reduce overheating and damage. For example, National Grid (MA) aims to change out residential transformers when they reach half-hour peak loads of 160 percent of rated capacity in the summer or 200 percent in the winter (see DPU 16-SG-11 Filing Attachment 2).

12. Sensitivity Analysis

The following sections detail the inputs and results of the sensitivity analysis. In AESC 2021, we evaluate avoided costs under three different sensitivities. These sensitivities include:

- A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 ("High Gas Price Sensitivity")
- A climate policy sensitivity, where avoided costs for energy efficiency are calculated under a hypothetical regional climate policy with increased levels of electrification and clean energy ("No New EE Climate Policy Sensitivity")
- A climate policy sensitivity which models energy efficiency along with increased levels of electrification and clean energy ("All-In Climate Policy Sensitivity")

These sensitivities were identified through consensus discussion among members of the Study Group.[332]

For each of these sensitivity cases, we find the following:

- In the High Gas Price Sensitivity, energy prices are 27 percent higher, capacity prices are 2 percent lower, RPS compliance costs are 8 percent lower, and non-embedded GHG costs are 21 percent lower. All prices are compared to Counterfactual #1.
- In the No New EE Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 52 percent higher, and RPS compliance costs are 12 percent higher. All prices are compared to Counterfactual #3. This sensitivity features a new avoided cost (the incremental regional clean energy policy compliance cost, or IRCEP), which captures the incremental cost of the region reaching 90 percent non-fossil generation by 2035. This category increases total levelized avoided costs by 0.9 percent.
- In the All-In Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 42 percent higher, and RPS compliance costs are 11 percent higher. All prices are compared to Counterfactual #2. The new IRCEP cost category increases total avoided costs by 0.4 percent, all else being equal.

All of the summary costs described above are framed in terms of 15-year levelized costs for summer on-peak for the WCMA region.

12.1. When and how to use these sensitivities

This section discuss caveats and considerations relating to the modeled sensitivities

[332] This discussion included the distribution of an informal survey by the Synapse Team. Other sensitivities considered, but not analyzed due to time and budget constraints, include a case examining more extended impacts of the COVID-19 pandemic (beyond the effects considered in the main counterfactuals) as well as other versions of a climate policy sensitivity.

High Gas Price Sensitivity

The first sensitivity (the High Gas Price Sensitivity) is modeled primarily because natural gas prices are one of the inputs to which the AESC Study is historically the most sensitive. AESC 2021 is no exception; one of the primary reasons for the decrease in energy values between AESC 2018 and AESC 2021 is the associated decrease in annual natural gas prices. The purpose of this sensitivity is to provide a set of potential avoided energy costs under a future in which natural gas prices prove to be higher than those modeled in the main counterfactuals.

Climate policy sensitivities

The No New EE Climate Policy Sensitivity models a future with ambitious levels of building electrification and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. This sensitivity does not model any incremental energy efficiency installed in 2021 or any later year. This means that it is a suitable sensitivity for considering avoided costs for energy efficiency in a future with more ambitious climate regional policies.

The All-In Climate Policy Sensitivity models a future with ambitious levels of energy efficiency, building electrification, and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. As a result, it can be interpreted not as an avoided cost, but as a projection of expected energy prices, capacity prices, and other price series in a future with ambitious climate policies. Or, it could be interpreted as a projection of avoided costs for energy efficiency and electrification measures beyond those modeled in this scenario. In other words, while the No New EE Climate Policy Sensitivity estimates avoided costs for the first unit or first many units of energy efficiency measures, the All-In Climate Policy Sensitivity estimates avoided costs for the last unit of energy efficiency, or the first unit of energy efficiency beyond what is modeled in this sensitivity.

There are a number of other important caveats to consider relating to the climate policy sensitivities:

- Both climate policy sensitivities model avoided costs under a very specific set of assumptions related to electrification and a hypothetical regional clean energy policy. Different assumptions related to either of these inputs could potentially yield different avoided costs than what are shown here. As a result, these sensitivities are likely most useful in terms of thinking about directions and orders of magnitudes of avoided costs, relative to the main AESC counterfactuals, rather than being useful as sources of avoided costs on their own.
- These sensitivities may be most useful for teeing up questions for future avoided cost studies. They highlight challenges in terms of framing, energy sector modeling, and clean energy policy design that have never before been considered in previous AESC studies. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.
- Some of the highest costs of a decarbonized grid are most likely after these sensitivities' modeling horizon (e.g., post-2035), when building and transportation electrification are expected to reach significant scale. The modeling horizons analyzed in these

sensitivities (which are consistent with the 15-year detailed modeling period used in the rest of this report) may undercount avoided costs that occur post-2035. These avoided costs may be of particular importance for measures with lifetimes longer than 12-15 years that are being considered for implementation between 2021 and 2024. Avoided costs derived from these sensitivities would likely be more informative or useful in practical settings if years after 2035 were modeled in more detail. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

12.2. Sensitivity inputs and methodologies

This section details the input assumptions and methodologies used in the construction of these sensitivities.

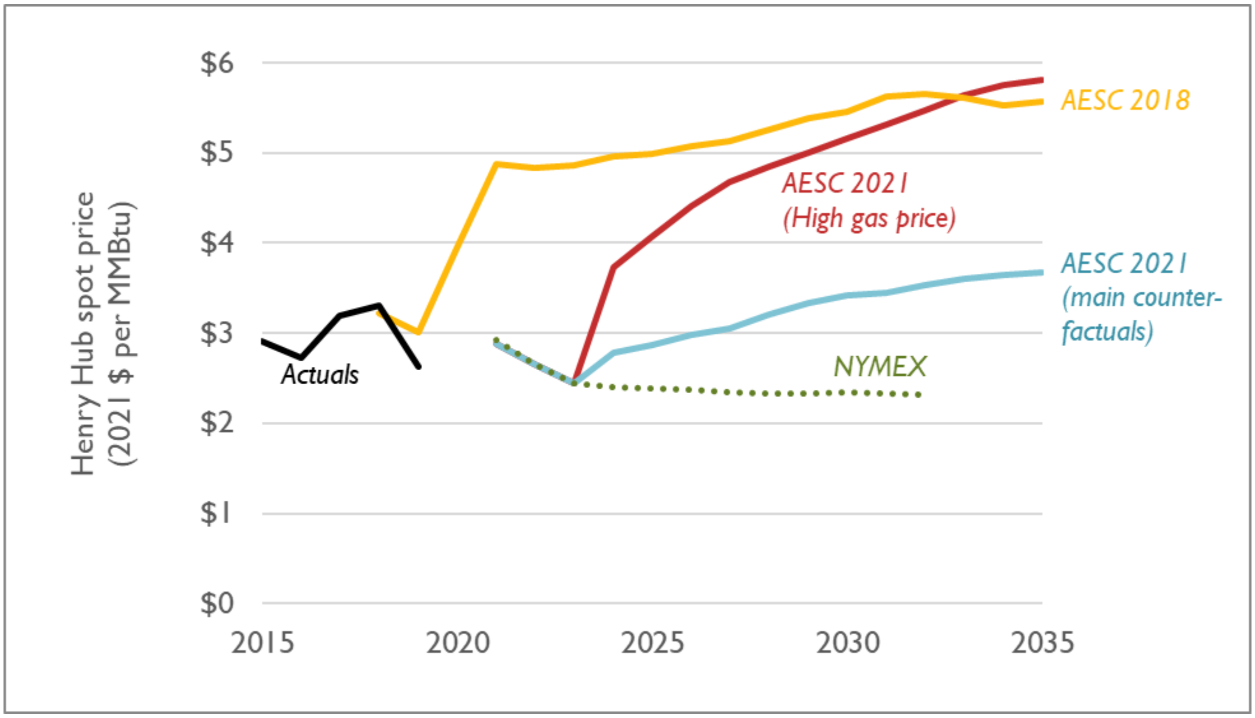
High Gas Price Sensitivity

The High Gas Price Sensitivity is a modification of Counterfactual #1. The primary change made in this sensitivity is a different assumption for long-term gas prices. Figure 52 illustrates the difference between the Henry Hub price used in the main four AESC 2021 counterfactuals and the gas price used in this sensitivity (other series are shown for comparative purposes). The high gas price is identical to the main price in 2021 through 2023. Between 2024 and 2035, the high gas price is 51 percent higher than the main case, on average.

The high gas price trajectory depicted in Figure 52 is created by swapping out the AEO 2021 Reference case series used to create mid- and long-term gas prices in the main four AESC counterfactuals for the AEO 2021 "Low oil and gas supply" case.[333] This series depicts a future with higher gas prices as a result of lower gas recovered per well and lower assumed rates of technological improvement (which would otherwise reduce costs and increase productivity). In this case, domestic natural gas production in 2035 is 30 Tcf, an 11 percent reduction compared to 2020 levels (for comparison, the AEO 2021 Reference case used as a data source for the gas price in the main AESC counterfactuals reaches 39 Tcf in 2035, a 14 percent increase compared to 2020).

[333] This was called the "Low oil and gas resource technology case" in earlier AEO studies, including the one used as a data source for AESC 2018. For more information on these cases, see "Annual Energy Outlook 2021: Case Descriptions." U.S. Energy Information Administration. February 2021. Available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/case_descriptions_2021.pdf.

Figure 52. Henry Hub price forecast in main AESC 2021 case and High Gas Price Sensitivity



We made no further changes to inputs for this sensitivity. This includes no changes to Algonquin basis prices, monthly price changes, or changes to load. Our modeling methodology otherwise followed the methodology described for the four main counterfactuals, as described above.

Climate policy sensitivities

The inputs for the two subsequent sensitivities are discussed together due a large overlap in assumptions. Generally speaking, the inputs in these sensitivities can be split into two categories: inputs that modify demand assumptions, and inputs that modify supply assumptions.

Modifications to demand

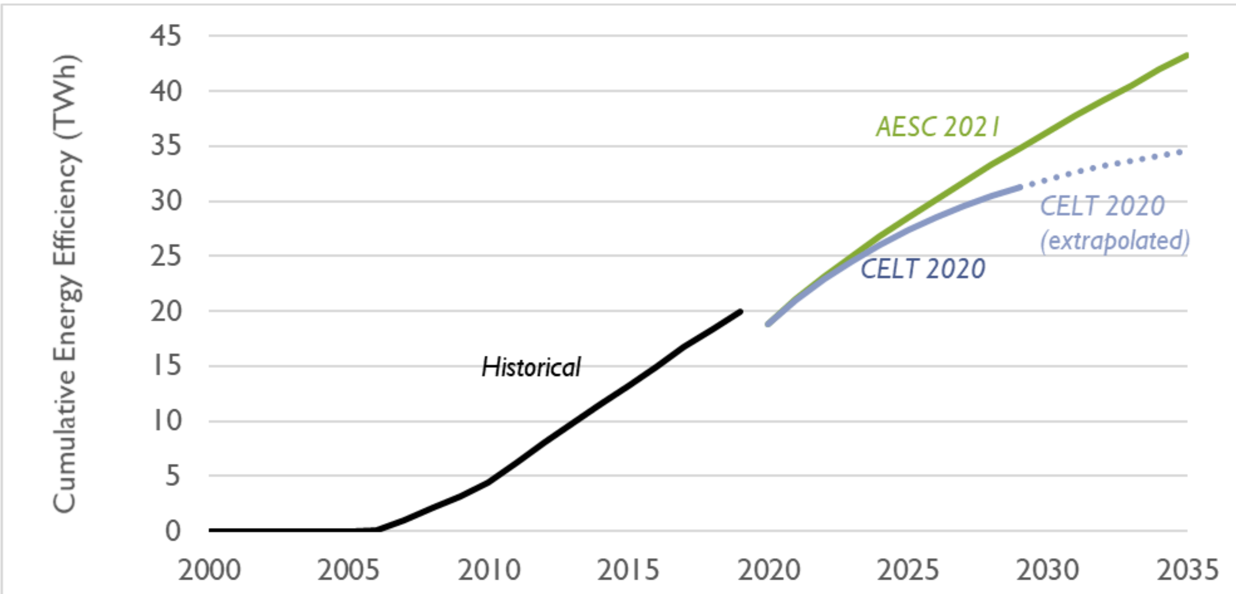
Depending on the climate policy sensitivity considered, we use a different counterfactual as a starting point. The No New EE Climate Policy Sensitivity relies on Counterfactual #3 as a starting point, whereas the All-In Climate Policy Sensitivity relies on Counterfactual #2 as a starting point. We make modifications to assumptions on energy efficiency, building electrification, transportation electrification, and active demand management.

Energy efficiency

In terms of energy efficiency assumptions, the No New EE Climate Policy Sensitivity does not differ from Counterfactual #3. Both series assume that no incremental energy efficiency is installed in 2021 or any later years.

The All-In Climate Policy Sensitivity uses the same energy efficiency assumptions as Counterfactual #2. Both modeling runs rely on a modified version of the energy efficiency forecast described in CELT 2020. This trajectory is illustrated in Figure 53 and discussed in detail above in Section 4.3: *New England system demand*. As in Counterfactual #2, hourly load profiles for energy efficiency match the load shape used in the econometric component of the energy forecast.

Figure 53. Historical and projected cumulative regionwide energy efficiency impacts used in the All-In Climate Policy Sensitivity



Notes: This is a reproduction of Figure 17. The All-In Climate Policy Sensitivity utilizes the "AESC 2021" trajectory for energy efficiency, which is the same assumption used in Counterfactual #2. No incremental energy efficiency installed in 2021 or any later year is modeled in the No New EE Climate Policy Sensitivity.

Building electrification

Both climate policy sensitivities envision a future with more ambitious building electrification policies than were modeled in the AESC 2021 counterfactuals. We note that Counterfactual #3 included some quantity of incremental building electrification (roughly 3.4 TWh regionwide by 2035, according to data produced by ISO New England in CELT 2020) while Counterfactual #2 maintained the level of building electrification identified in 2020 throughout the study period.

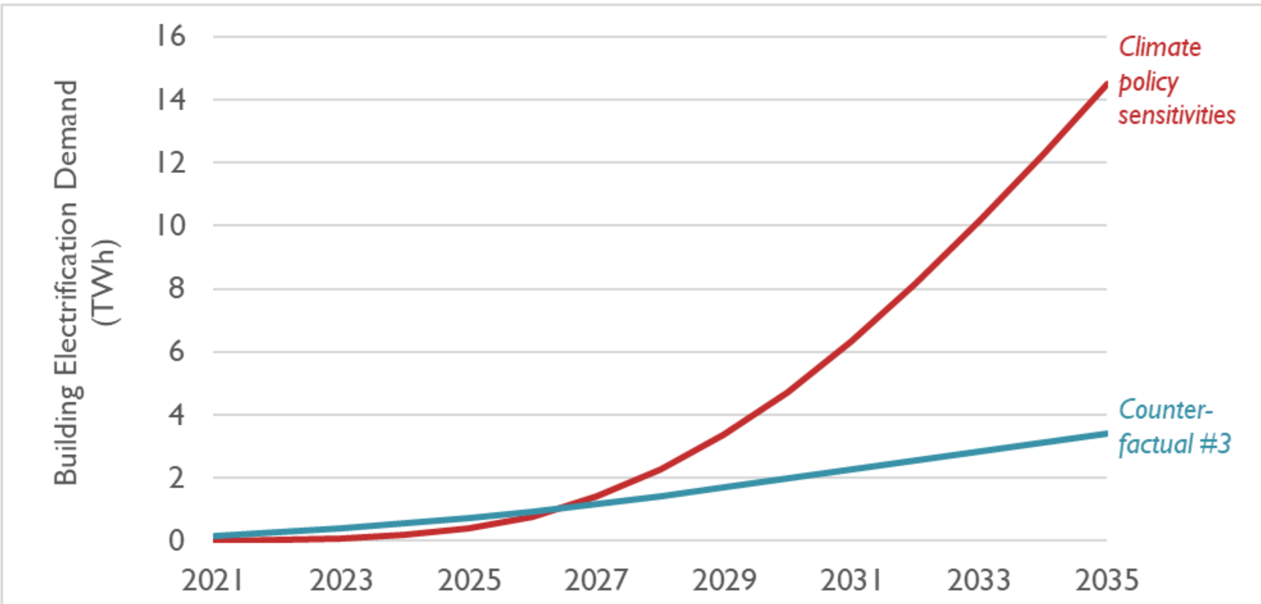
Both climate policy sensitivities use an entirely different projection for building electrification. We rely on inputs described in the December 2020 *Decarbonization Roadmap* study published by the Massachusetts Executive Office of Energy and Environmental Affairs (MA EEA).[334] This study envisions a

[334] A series of reports relevant to the *Decarbonization Roadmap* study can be found at https://www.mass.gov/info-details/ma-decarbonization-roadmap. Detail on building electrification measures can be found in *Building Sector Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study.* December 2020. Massachusetts Executive Office of Energy and Environmental Affairs. Available at https://www.mass.gov/doc/building-sector-technical-report/download.

number of different pathways in which all six New England states (as well as a number of other jurisdictions in the Northeast) achieve net-zero GHG emissions by 2050.

Specifically, we rely on building decarbonization data from the *Decarbonization Roadmap*'s "All Options" case. This case projects an increase in building electrification demand of about 14 TWh in 2035, relative to 2020 levels (see Figure 45).[335] This includes demand from both residential and commercial sectors, and it includes load related to space heating as well as water heating. We note that MA EEA's modeling is conducted through 2050; in 2050, MA EEA projects a total of 44 TWh related to building electrification throughout New England.[336]

Figure 54. Building electrification trajectory used in the climate policy sensitivities, compared with the trajectory used in Counterfactual #3



Note: No incremental building electrification measures installed in 2021 or any later year are modeled in Counterfactual #2.

As in Counterfactual #3 and other AESC 2021 counterfactuals, the hourly load profile assumed for building electrification in this sensitivity analysis relies on load shape data published by ISO New England in CELT 2020. See Section 4.3: *New England system demand* for more information.

[335] Detailed annual and state-specific data was provided to Synapse Team by MA EEA via email in January through March 2021. We note that at the time of AESC 2021's sensitivity analysis, MA EEA is continuing to model scenarios for its Interim Clean Energy and Climate Report for 2030 (more information is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2030). Later scenarios discussed or published by MA EEA may explore different levels of building electrification than was used in this analysis.

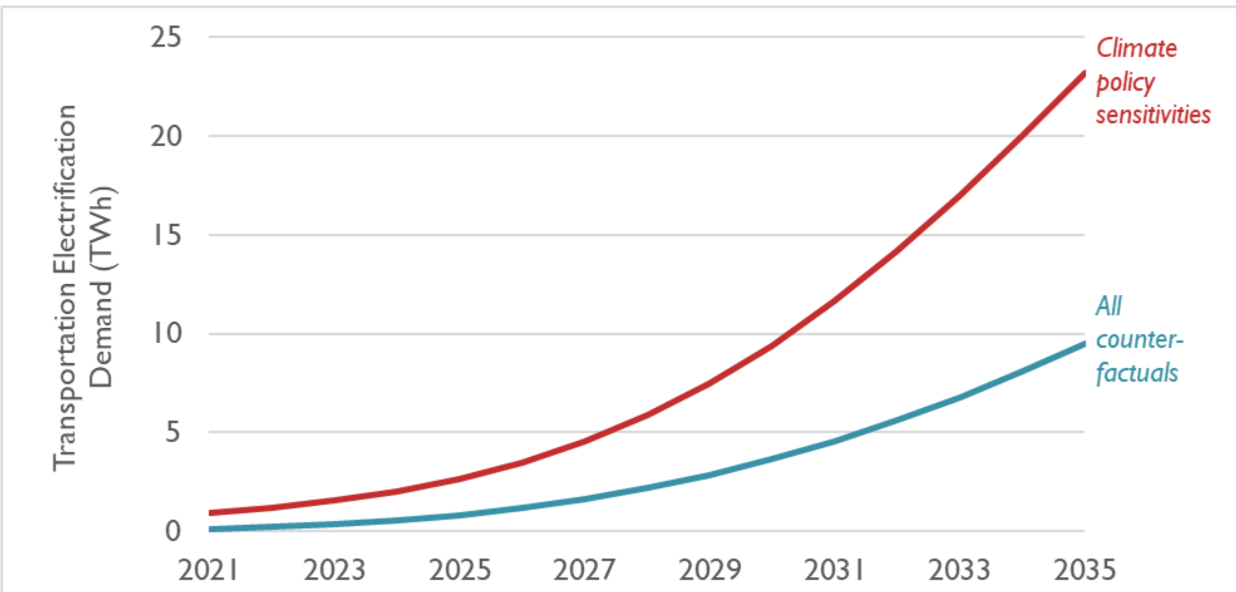
[336] As with all modeling in AESC 2021, our sensitivity analysis focuses on the years 2021 through 2035.

Transportation electrification

In all of the AESC counterfactuals, we rely on a forecast of transportation electrification demand based on Bloomberg New Energy Finance's (BNEF) *Electric Vehicle Outlook 2020*. By 2035, this projection results in 9.5 TWh of transportation electrification demand throughout New England. See Section 4.3: *New England system demand* for more information on how this projection was developed.

As with building electrification, the more ambitious trajectories for transportation electrification modeled in the AESC 2021 climate policy sensitivities are based on data from MA EEA's *Decarbonization Roadmap*. As with building electrification, we rely on annual, state-specific data for the "All Options" case, as provided to the Synapse Team by MA EEA. This projection includes demand from light-, medium-, and heavy-duty vehicles. This projection results in 23.2 TWh of transportation electrification demand throughout New England in 2035 (see Figure 55).

Figure 55. Transportation electrification trajectory used in the climate policy sensitivities, compared with the trajectory used in the AESC counterfactuals



Consistent with the AESC 2021 counterfactuals, the hourly load profile assumed for transportation electrification in this sensitivity analysis relies on load shape data published by ISO New England in CELT 2020. See Section 4.3: *New England system demand* for more information.

Flexible load

The the climate policy sensitivities feature exogenous flexible load resources not modeled in the main AESC counterfactuals. For the purposes of this section, flexible load is defined as the ability of some end-uses to shift the consumption of electricity from one hour to another. Examples of flexible load might include a program that requires, compensates, or requests EV owners to charge their vehicles at a later time, or for owners of electric water heaters to pre-heat their water several hours ahead of expected use.

The four main counterfactuals in AESC 2021 do not explicitly model any flexible load.[337] Instead, end-uses that are expected to allow for flexible load utilize simple, static hourly load shapes (see Section 4.3: *New England system demand* for more information on the assumed load shapes).

To determine an appropriate quantity of flexible load to model in our climate policy sensitivities, we relied upon the *Decarbonization Roadmap* study described above. Documentation for this study provides high-level information on the quantity of flexible load modeled in 2050 in Massachusetts for a number of different end-uses (including water heating, space heating, cooling, and light-duty vehicles).[338] In 2050, MA EEA models about 20 percent of Massachusetts' space and water heating demand being flexible (with a 1- or 2-hour advance or delay), and 50 percent of Massachusetts' LDV demand being flexible (with an 8-hour delay option only). We expand these percentages to the entire region (assuming that the rest of the region implements flexible load on a similar scale) and to years in the AESC 2021 Study Period (based on the modeled level of electrification in 2021 through 2035, relative to 2050). These calculations imply 600 MW of flexible load for space and water heating will be available regionwide in 2035, and 1,125 MW of flexible load for electric LDVs will be available in 2035. Figure 56 illustrates the quantities of flexible load that we modeled in each year. These quantities of flexible load were then assigned to each state based on each state's recent historical electricity demand relative to regionwide demand.

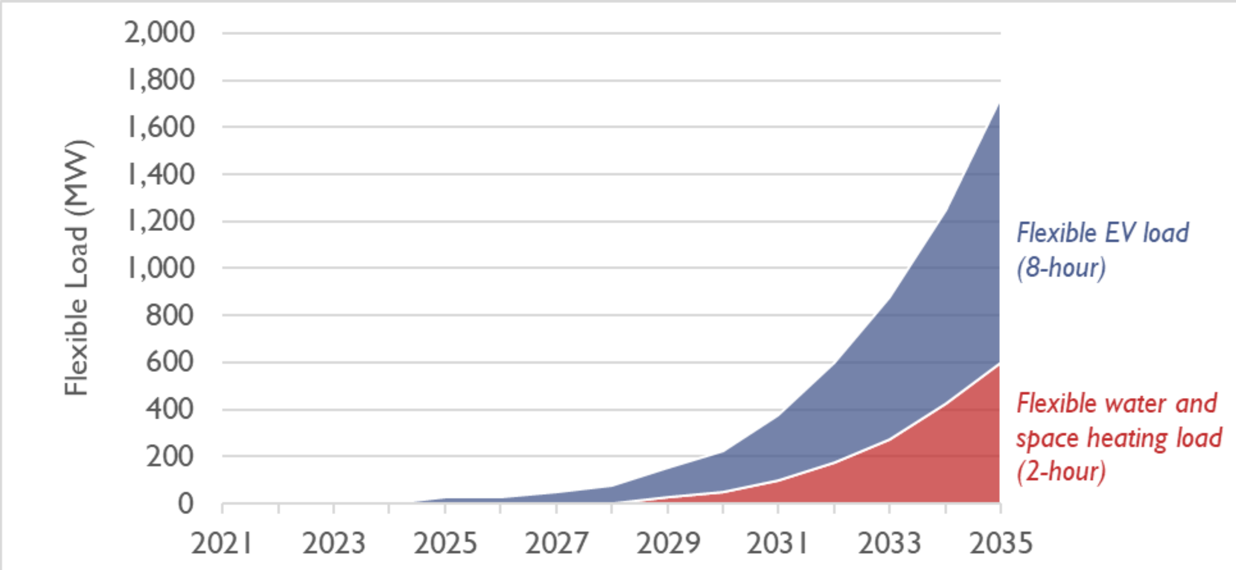
Flexible load is assumed to be eligible for capacity payments. We assume that, like other demand response resources, flexible load has a capacity credit of 90 percent (the same assumption used for battery storage). It is possible that in reality flexible load resources would require some other out-of-market payments or incentives. However, those costs are not modeled in this sensitivity analysis.[339]

[337] However, we note that all counterfactuals include some amount of active demand management, including demand response and behind-the-meter storage.

[338] Detail on flexible load is presented in Section 7.10 of MA EEAs' technical appendix titled *Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study*, available at https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[339] This is consistent with how this analysis models costs related to building electrification and transportation electrification. Only costs related to existing electricity markets (e.g., energy, capacity RPS, and others) are modeled. Costs associated with other programs are not included.

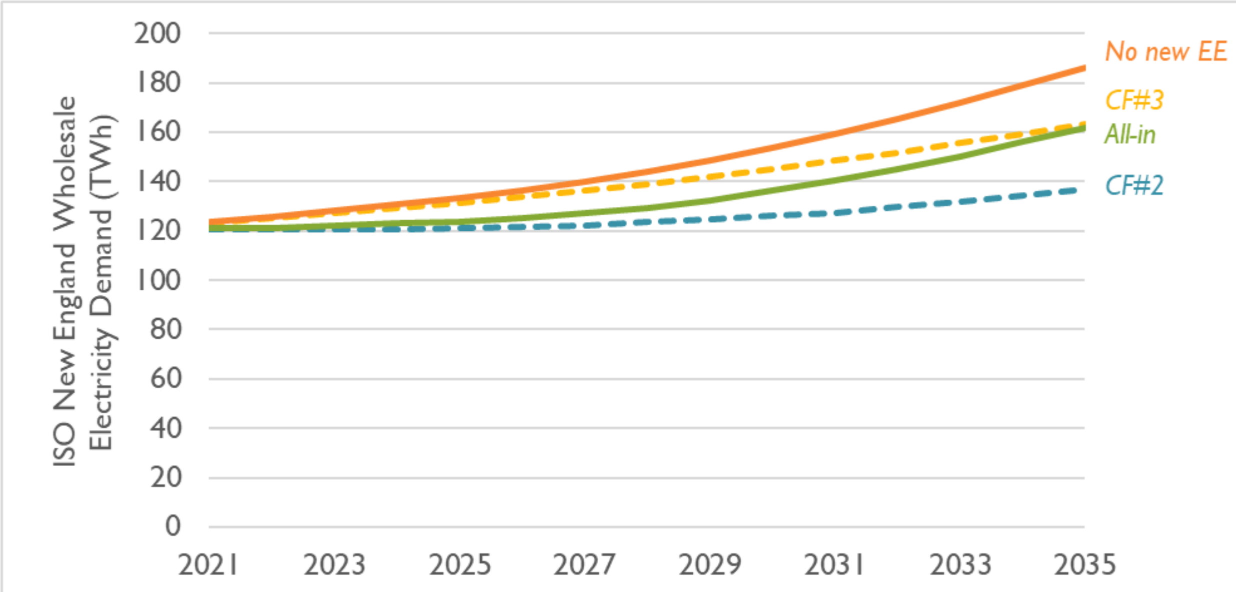
Figure 56. Proposed quantities of flexible load to be modeled in the climate policy sensitivities



Aggregate impacts

The demand-side policies described in the previous sections are combined with the econometric load forecast and produce the aggregate demand trajectories shown in Figure 57. Demand trajectories for Counterfactual #2 (CF#2) and Counterfactual #3 (CF#3) are shown for comparative purposes. We observe that systemwide demand in the All-In Climate Policy Sensitivity coincidently ends at roughly the same level as Counterfactual #3, although it follows a different trajectory (particularly during the mid- to late-2020s). Meanwhile, the No New EE Climate Policy Sensitivity closely resembles Counterfactual #3 through the mid-2020s before diverging and ending at a level roughly 23 TWh than Counterfactual #3 in 2035.

Figure 57. Systemwide wholesale demand in the No New EE and All-In Climate Policy Sensitivities



Modifications to supply

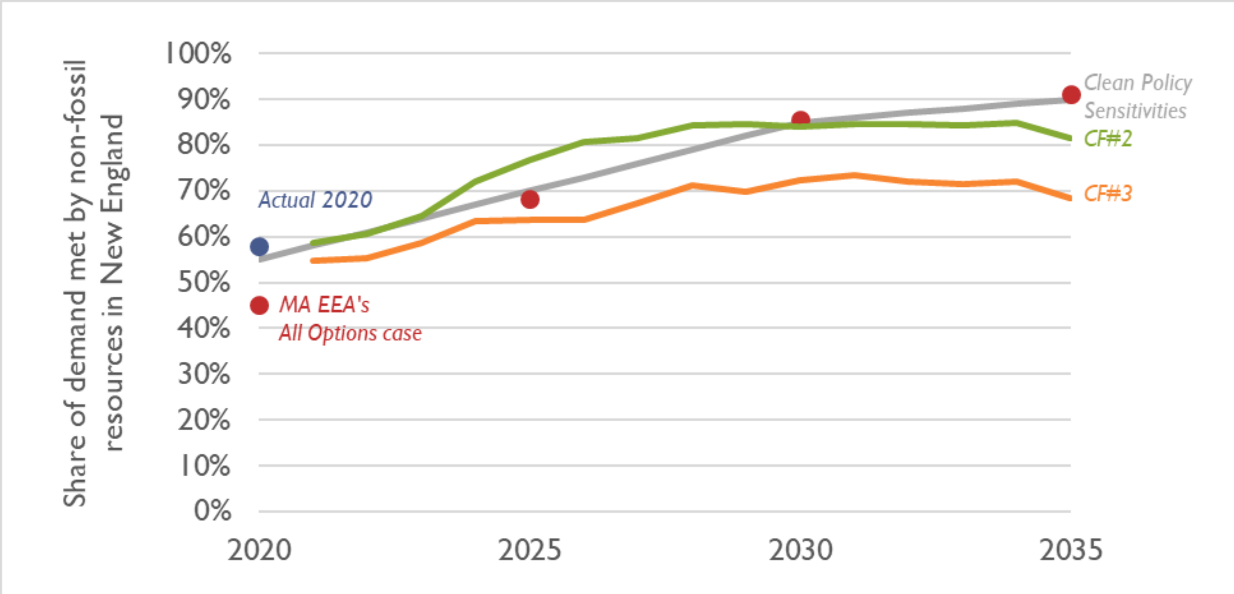
The climate policy sensitivities also envision changes to energy supply, beyond what is described elsewhere in this report. In short, we model an increasing amount of regional electricity demand being met with non-fossil resources. In our climate policy sensitivities, resources that are defined as "fossil" include resources where electricity is generated from burning coal, natural gas, or oil. All other resources are non-fossil, and include wind, solar, hydro, nuclear, biomass, imports, municipal solid waste, and other miscellaneous resource types.

To determine what level of incremental non-emitting supply should be modeled from 2021 through 2035, we return to the "All Options" case in MA EEA's *Decarbonization Roadmap*.[340] The "All Options" case achieves a non-emitting share of 68 percent in 2025, 84 percent in 2030, and 91 percent in 2035. Relying on this data, as well as actual data on the share of non-emitting supply in 2020 from ISO New England, the Synapse Team developed a clean policy trajectory from 2020 to 2035 (see Figure 58). This trajectory begins at 55 percent in 2020, reaches 70 percent in 2025, 85 percent in 2030, and finally 90 percent in 2035. Values in all other years are interpolated.

We do not model any additional renewable procurement policies beyond what is already modeled in the main AESC sensitivities. See Section 7.2 *Renewable Energy Certificate (REC) Price Forecasting* for more information on renewable procurement assumptions.

[340] Detailed annual and state-specific data was provided to Synapse Team by MA EEA via email in January through March 2021.

Figure 58. Shares of demand met by non-fossil resources in Counterfactual #2 (CF#2), Counterfactual #3 (CF#3), MA EEA's All Options Case, and the climate policy sensitivities



<u>Developing an incremental regional clean energy policy</u>

We multiply the clean policy trajectory (Figure 58) by the annual demand requirements (Figure 57) to estimate how much total non-fossil supply needs to be provided under the two climate policy sensitivities in each year. For both climate policy sensitivities, we then subtract the amount of non-fossil supply that is currently modeled in the "starting" counterfactuals (Counterfactual #3 for the No New EE Climate Policy Sensitivity and Counterfactual #2 for the All-In Climate Policy Sensitivity). This provides an initial estimate of how much more non-fossil supply is required to meet the clean policy trajectory. We then perform a series of steps to iterate on this TWh requirement:

- First, we model the policy as beginning in 2025. This is done because new renewable policies in New England frequently have a period between when they are codified and when they go into effect. This period allows the market to begin to respond to the policy and ramp up the production of new clean energy several years ahead of time.
- Second, we simplify the early years of the policy to allow for a gradual phase-in. Again, this is done to allow the clean energy market to respond to the policy and avoid non-compliance with or very high prices for the policy in the mid- to late-2020s.
- Third, we perform an interactive check to evaluate whether the clean policy trajectory described in Figure 58 is achieved.

We created the IRCEP to drive the deployment of this additional clean energy quantity. For the purposes of these sensitivities, the IRCEP has the following parameters:

- IRCEP functions like a new, additional RPS policy covering New England. Using the IRCEP requirements described above, the REMO model identifies which resources are most cost-effective for each sensitivity. Depending on the sensitivity and the year, we observe that these resources include onshore wind, utility-scale solar, and offshore wind.[341]

- IRCEP is a "wrap-around" policy, similar to the Massachusetts CES. To this end, all currently enacted RPS targets count toward satisfaction of the IRCEP. All incremental demand (above current RPS policies) is assumed fulfilled by Class I-eligible resources as defined by states with Class I RPS policies (e.g., Massachusetts, Connecticut, Rhode Island, Maine, and New Hampshire). In general, this includes land-based wind, offshore wind, solar, small hydro facilities meeting minimum sustainability criteria, and ocean energy systems. These resources may be built anywhere in New England or in adjacent control areas and have energy and RECs delivered to ISO New England.

- Unlike RPS policies, the IRCEP (as it is modeled here) does not include the flexibility to bank excess compliance in one year for application in a future year.

- Ordinarily, an RPS policy identifies entities who must legally comply with the policy. For example, in practice, Massachusetts load-serving entities (e.g., Eversource, National Grid, Until, and all competitive retail electricity providers) must retire a specific number of RECs to fulfill the Class 1 RPS requirement for each year. Because the IRCEP is a simplified, hypothetical, regionwide policy created to identify a shadow price of compliance with a climate policy, we do not specify the ultimate means of compliance.

Other resource builds

Unlike the main four counterfactuals in AESC 2021 and the High Gas Price Sensitivity, we disable the model's ability to build new natural gas-fired generators in the two climate policy sensitivities. This is done to align the sensitivities with a future in which 90 percent of electricity is supplied by non-fossil sources.[342]

However, the capacity expansion model is allowed to build energy storage resources. While energy storage is not a resource that will be built to fulfill IRCEP requirements, energy storage resources are available to be built if they are deemed economic. Reasons for economic builds might include reliability requirements for capacity (e.g., due to increased load associated with electrification) or low or negatively priced energy in some hours (e.g., as a result of a large supply of zero-marginal-cost renewables) and high-priced energy in other hours (e.g., when demand due in part to electrified end-uses is high, but supply from renewables is low). See Section 4.5: *Anticipated non-renewable resource additions and retirements* for more discussion on energy storage.

[341] In particular, the cost of offshore wind is assumed to fall over time as later projects take advantage of transmission infrastructure constructed to serve earlier projects.

[342] We performed a number of exploratory runs examining outcomes with natural gas builds allowed. We observed largely consistent finding with the results described here, with similar energy and capacity prices.

Interpreting the resulting costs

IRCEP functions as an RPS policy across the six states. As with other RPS polices, it requires the purchase of RECs in order to comply, implying a cost of compliance.

For each state, we calculate costs resulting from the IRCEP as follows:

1. First, we calculate the total RPS percentage from new and existing programs, absent the IRCEP (see Table 55 and Table 56). In some states and years, this value is as low as 25 percent. In other states and years, this value is as high as 100 percent.
2. Second, we subtract the percentages calculated in Step 1 from the percentages associated with the clean energy trajectory. In some states and years, this calculation implies that 65 percent of statewide load is subject to IRCEP. In other states and years, this value is 0 percent. This percentage describes the amount of clean energy avoided by every 1 MWh of energy efficiency (e.g., a value of 65 percent means that for every 1 MWh of energy efficiency installed, 0.65 MWh of IRCEP-derived clean energy would be avoided).
3. Finally, we multiply the resulting percentages from Step 2 by the calculated cost of new entry for each year, for each state. This cost varies depending on which resources are marginal.

The resulting values would be the cost of compliance under IRCEP for each state. The above methodology is similar to the costs of RPS compliance calculations described in Section 7.3: *Avoided RPS compliance cost per MWh reduction.*

12.3. Results of sensitivity analysis

The following sections detail the results of the sensitivity analysis for energy prices, capacity prices, RPS compliance, and other avoided cost categories.

High Gas Price Sensitivity

This sensitivity is a modification of Counterfactual #1 using a higher natural gas price. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #1. A summary of the changes in avoided costs is shown in Table 131.

Table 131. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 High Gas Price Sensitivity versus AESC 2021 Counterfactual #1

	Counter-factual #1	High Gas Price Sensitivity	High Gas Price Sensitivity, relative to Counterfactual #1		*Notes*
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.18	1.15	-0.03	-2%	*3,4,5,6*
Avoided Retail Energy Costs	3.85	4.89	1.05	27%	*5,7,8*
Avoided RPS Compliance	1.28	1.17	-0.10	-8%	*5,7,9*
Subtotal: Capacity and Energy	**6.30**	**7.21**	**0.92**	**15%**	
GHG non-embedded	**4.74**	**3.75**	**-0.98**	**-21%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**0%**	*3,5,6,12*
Electric capacity DRIPE	0.41	0.41	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.20	1.39	0.19	16%	*5,7,13*
Subtotal: DRIPE	**1.61**	**1.80**	**0.19**	**12%**	**-**
Total	**14.77**	**14.89**	**0.12**	**1%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #1 cost (2021 $/kW-year) of $49/kW-year
AESC 2021 High Gas Price Sensitivity cost (2021 $/kW-year) of $48/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh in Counterfactual #1 and $42/MWh in the High Gas Price Sensitivity
9. Avoided RPS compliance cost of $12/MWh in Counterfactual #1 and $11/MWh in the High Gas Price Sensitivity
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year in Counterfactual #1 and $0.47/kW-year in the High Gas Price Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

Energy prices

Table 132 compares the wholesale energy price results for this sensitivity with Counterfactual #1. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that the changes in levelized energy prices for this sensitivity correspond with the differences in Henry Hub prices described above.[343] As in Counterfactual #1, natural gas generators are the marginal resource in most hours of this sensitivity and typically set the price.

Table 132. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
High Gas Price Sensitivity	$49.79	$55.80	$54.27	$41.57	$38.57
% Change	22%	19%	20%	27%	29%

Notes: Levelization period is 2021–2035 and real discount rate is 0.81 percent.

Capacity prices

Compared to Counterfactual #1, the 15-year levelized capacity price in the High Gas Price Sensitivity is 2 percent lower (see Table 133). This is because the two cases are identical from FCA 12 through FCA 24 (with no differences in resource builds or demand) with only minor differences in resource builds in 2034 and 2035 as a result of higher gas and energy prices.

[343] Note that a one percentage point increase in the Henry Hub price does not correspond to a one percentage point increase in the energy price. This is because other components which contribute to the energy price (e.g., plant heat rates, Algonquin Basis) are unchanged in the two natural gas price sensitivities.

Table 133. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #1	AESC 2021 High Gas Price Sensitivity
2021/2022	12	$4.77	$4.77
2022/2023	13	$3.96	$3.96
2023/2024	14	$2.47	$2.47
2024/2025	15	$2.75	$2.75
2025/2026	16	$2.72	$2.72
2026/2027	17	$2.88	$2.88
2027/2028	18	$3.11	$3.11
2028/2029	19	$3.30	$3.30
2029/2030	20	$3.59	$3.59
2030/2031	21	$3.42	$3.42
2031/2032	22	$3.67	$3.67
2032/2033	23	$3.90	$3.90
2033/2034	24	$3.86	$3.86
2034/2035	25	$4.67	$3.75
2035/2036	26	$3.66	$3.24
15-year levelized cost		**$3.51**	**$3.42**
Percent difference			**-2%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Cost of RPS compliance

Table 134 shows how the cost of RPS compliance changes in the High Gas Price Sensitivity, relative to Counterfactual #1. Depending on the state and RPS class, costs of compliance in the High Gas Price Sensitivity are between 0 and 17 percent lower than in Counterfactual #1. Generally, higher gas prices yield lower costs of RPS compliance, as the renewables built to fulfill these RPS requirements are able to obtain a larger amount of revenue from the energy market. As a result, they require less in the way of additional costs from the sale of RECs, which lowers the cost of RPS compliance.

Table 134. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #1	Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
	Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**
High Gas Price Sensitivity	Class 1/New	$5.65	$5.73	$4.76	$2.35	$12.50	$1.15
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.96	$5.39	$0.03	$2.33
	Total	**$6.99**	**$6.18**	**$10.86**	**$7.74**	**$12.53**	**$3.47**
Percent Difference	Class 1/New	-14%	-17%	-15%	-11%	-16%	-14%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	-4%	-1%	16%	-9%
	Total	**-12%**	**-16%**	**-8%**	**-4%**	**-16%**	**-11%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #1, avoided costs for PTF, NO_X non-embedded, and capacity DRIPE in the High Gas Price Sensitivity are either identical or nearly so. We observe higher energy and cross-DRIPE values as a result of higher energy prices. Finally, we observe that the GHG non-embedded cost is about 20 percent lower than in Counterfactual #1. This is because when this value is based on a New England-based marginal abatement cost, one of the inputs to this value is energy prices. Higher energy prices imply a smaller residual cost for the marginal resource (in this case, offshore wind), causing the compliance cost to decrease.

No New EE Climate Policy Sensitivity

This sensitivity is a modification of Counterfactual #3 with higher loads and more clean energy. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #3. A summary of the changes in avoided costs is shown in Table 135. This table differs from similar versions of this table found throughout this report in that it includes a separate line for avoided costs related to IRCEP compliance. It also differs from other versions in that the "GHG non-embedded" row in Table 135 utilizes the social cost of carbon, rather than the marginal abatement cost derived from the New England electricity sector. This is because in some ways, the entire sensitivity is a marginal abatement cost calculation. As a result, we do not provide this comparison in the report in order to avoid improper comparisons and applications. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

Table 135. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 No New EE Climate Policy Sensitivity versus AESC 2021 Counterfactual #3, using the SCC

	Counter-factual #3	No New EE Climate Policy Sensitivity	No New EE Climate Policy Sensitivity, relative to Counterfactual #3		*Notes*
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.22	1.86	0.64	52%	*3,4,5,6*
Avoided Retail Energy Costs	3.92	3.79	-0.12	-3%	*5,7,8*
Avoided RPS Compliance	1.40	1.56	0.17	12%	*5,7,9*
Avoided IRCEP Costs	-	0.15	-	-	*14*
Subtotal: Capacity and Energy	**6.54**	**7.37**	**0.83**	**13%**	
GHG non-embedded (based on SCC)	**4.87**	**4.87**	**0.00**	**0%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**0%**	*3,5,6,12*
Electric capacity DRIPE	0.41	0.41	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.21	1.20	-0.01	-1%	*5,7,13*
Subtotal: DRIPE	**1.62**	**1.61**	**-0.01**	**-1%**	**-**
Total	**15.15**	**15.96**	**0.81**	**5%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #3 cost (2021 $/kW-year) of $51/kW-year
AESC 2021 No new EE climate policy sensitivity cost (2021 $/kW-year) of $79/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh in Counterfactual #3 and $32/MWh in the No New EE Climate Policy Sensitivity
9. Avoided RPS compliance cost of $13/MWh in Counterfactual #3 and $16/MWh in the No New EE Climate Policy Sensitivity
10. Assumes non-embedded GHG cost based on the social cost of carbon in both cases
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year in Counterfactual #3 and $0.47/kW-year in the No New EE Climate Policy Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
14. The IRCEP cost represents this state's incremental cost of deploying enough clean energy for the region to reach 90 percent clean energy by 2035.

Energy prices

Table 136 compares the wholesale energy price results for this sensitivity with Counterfactual #3. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that prices are 4 percent lower than estimated in Counterfactual #3. This is largely due to zero-marginal-cost renewables lowering the clearing price. However, as in Counterfactual #3, natural gas generators are the marginal resource in most hours and typically set the price.

Table 136. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
No New EE Climate Policy Sensitivity	$39.82	$46.20	$43.62	$32.23	$28.02
% Change	-4%	-3%	-4%	-3%	-6%

Notes: Levelization period is 2021–2035 and real discount rate 0.81 percent.

Capacity prices

Compared to Counterfactual #3, the 15-year levelized capacity price in the No New EE Climate Policy Sensitivity is 55 percent higher (see Table 137 and Figure 59). Capacity price trajectories are similar until FCA 22, at which point the two series diverge. Capacity prices in the No New EE Climate Policy Sensitivity increase, nearing or reaching the price ceiling implied by the MRI curve in FCA 24 through FCA 26. This price increase is due to a rapid increase in peak demand due to electrification, particularly in FCA 24 through FCA 26 when the system switches to winter peaking.

To model capacity prices in winter peaking years, we follow an identical methodology described above in Chapter 5: *Avoided Capacity Costs*, with two exceptions: (1) we rely on winter peak values to inform the demand quantity and (2) we adjust the capacity contribution for solar and wind to reflect more accurate seasonal capacity contributions from these resources.[344] Otherwise, we assume that the market's operation is unchanged. Likewise, other results that are derived from the capacity price modeling (e.g., capacity DRIPE, reliability) are derived using identical methodologies to that described in previous chapters.

We note that the operation of the capacity market in a winter-peaking future is highly uncertain. However, given what we know about the structure of the market as it exists today, the above changes are the only necessary modifications to successfully model a capacity price.

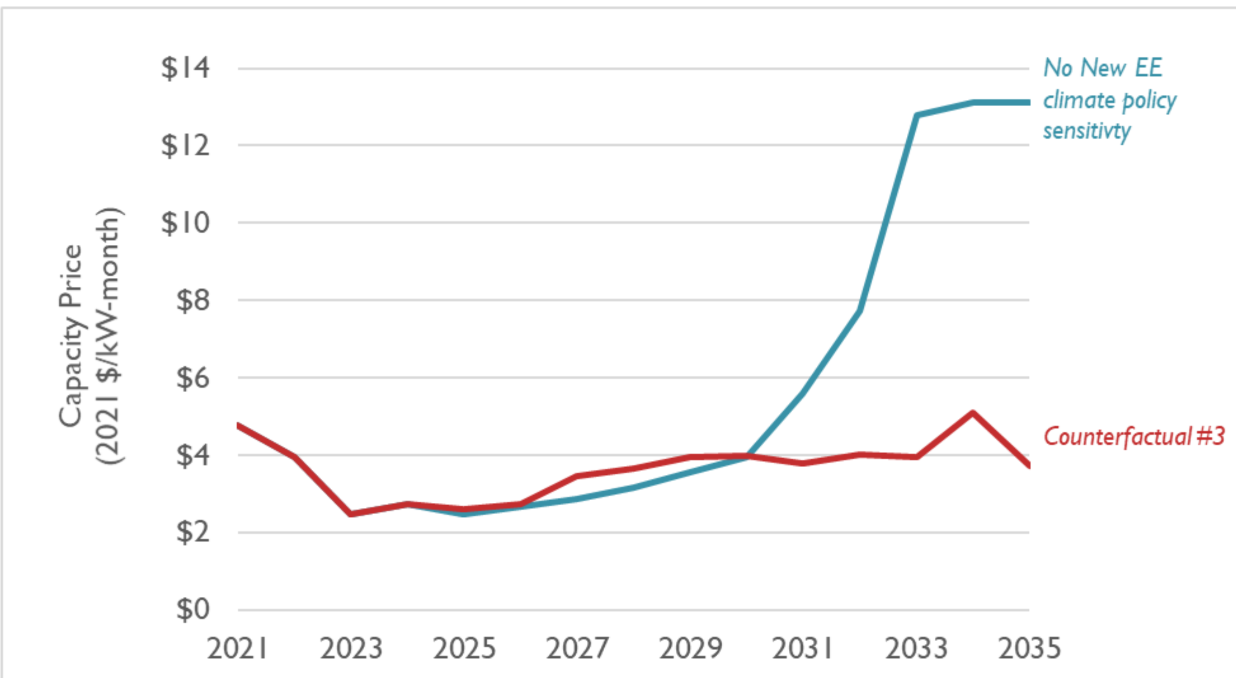
[344] Based on historical data from ISO New England on capacity obligations (see FCA Obligations workbook at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx) we assume that the winter capacity contribution of wind is double the summer capacity contribution, and that the winter capacity contribution of solar is 0 percent.

Table 137. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #3	AESC 2021 No New EE Climate Policy Sensitivity
2021/2022	12	$4.77	$4.77
2022/2023	13	$3.96	$3.96
2023/2024	14	$2.47	$2.47
2024/2025	15	$2.75	$2.75
2025/2026	16	$2.59	$2.46
2026/2027	17	$2.75	$2.66
2027/2028	18	$3.46	$2.86
2028/2029	19	$3.65	$3.15
2029/2030	20	$3.94	$3.57
2030/2031	21	$3.97	$3.95
2031/2032	22	$3.79	$5.59
2032/2033	23	$4.02	$7.73
2033/2034	24	$3.95	$12.80
2034/2035	25	$5.09	$13.13
2035/2036	26	$3.73	$13.13
15-year levelized cost		**$3.65**	**$5.56**
Percent difference			**52%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Figure 59. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)



Cost of RPS compliance

Table 138 shows how the cost of RPS compliance changes in the No New EE Climate Policy Sensitivity, relative to Counterfactual #3. Depending on the state and RPS class, costs of compliance in the No New EE Climate Policy Sensitivity are between 0 and 30 percent higher than in Counterfactual #3. This increase in compliance costs is due to increased energy demand, and as a result, increased REC prices and resulting RPS compliance costs.

Table 138. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #3	Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
	Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**
No New EE Climate Policy Sensitivity	Class 1/New	$8.82	$10.55	$8.15	$4.07	$21.61	$1.92
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.17	$5.54	$0.03	$3.23
	Total	**$10.16**	**$11.00**	**$14.47**	**$9.62**	**$21.64**	**$5.15**
Percent Difference	Class 1/New	18%	30%	22%	28%	29%	22%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	2%	1%	16%	13%
	Total	**15%**	**28%**	**12%**	**11%**	**29%**	**16%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #3, avoided costs for PTF, NO_X non-embedded, capacity DRIPE, energy DRIPE and cross-DRIPE in the No New EE Climate Policy Sensitivity are either identical or nearly so.

All-In Climate Policy Sensitivity

This sensitivity is a modification of Counterfactual #2 with higher loads and more clean energy. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #2. A summary of the changes in avoided costs is shown in Table 139. This table differs from similar versions of this table found throughout this report in that it includes a separate line for avoided costs related to IRCEP compliance. It also differs from other versions in that the "GHG non-embedded" row in Table 135Table 139 utilizes the social cost of carbon, rather than the marginal abatement cost derived from the New England electricity sector. This is because in some ways, the entire sensitivity is a marginal abatement cost calculation. As a result, we do not provide this comparison in the report in order to avoid improper comparisons and applications. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

Table 139. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 All-In Climate Policy Sensitivity versus AESC 2021 Counterfactual #2, using the SCC

	Counter-factual #2	All-In Climate Policy Sensitivity	All-In Climate Policy Sensitivity, relative to Counterfactual #2		*Notes*
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.16	1.64	0.48	42%	*3,4,5,6*
Avoided Retail Energy Costs	3.63	3.49	-0.14	-4%	*5,7,8*
Avoided RPS Compliance	0.98	1.08	0.11	11%	*5,7,9*
Avoided IRCEP Costs	-	0.06	-	-	*14*
Subtotal: Capacity and Energy	**5.77**	**6.28**	**0.51**	**9%**	
GHG non-embedded (based on SCC)	**4.87**	**4.87**	**0.00**	**0%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**-1%**	*3,5,6,12*
Electric capacity DRIPE	0.39	0.39	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.08	1.10	0.02	2%	*5,7,13*
Subtotal: DRIPE	**1.47**	**1.48**	**0.02**	**1%**	**-**
Total	**14.22**	**14.75**	**0.53**	**4%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #2 cost (2021 $/kW-year) of $48/kW-year
AESC 2021 All-in climate policy sensitivity cost (2021 $/kW-year) of $68/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $31/MWh in Counterfactual #2 and $29/MWh in the All-In Climate Policy Sensitivity
9. Avoided RPS compliance cost of $9/MWh in Counterfactual #2 and $10/MWh in the All-In Climate Policy Sensitivity
10. Assumes non-embedded GHG cost based on social cost of carbon in both cases
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.46/kW-year in Counterfactual #2 and $0.45/kW-year in the High Gas Price Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
14. The IRCEP cost represents this state's incremental cost of deploying enough clean energy for the region to reach 90 percent clean energy by 2035.

Energy prices

Table 140 compares the wholesale energy price results for this sensitivity with Counterfactual #2. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that prices are 3 percent higher than estimated in Counterfactual #2. Price increases due to higher loads are largely offset by price decreases due to zero-marginal-cost renewables lowering the clearing price. Winter prices increase as a result of higher winter loads caused by building and transportation electrification.

Table 140. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
All-In Climate Policy Sensitivity	$38.87	$45.70	$43.27	$29.64	$26.63
% Change	3%	6%	4%	-4%	-5%

Notes: Levelization period is 2021–2035 and real discount rate is 0.81 percent.

Capacity prices

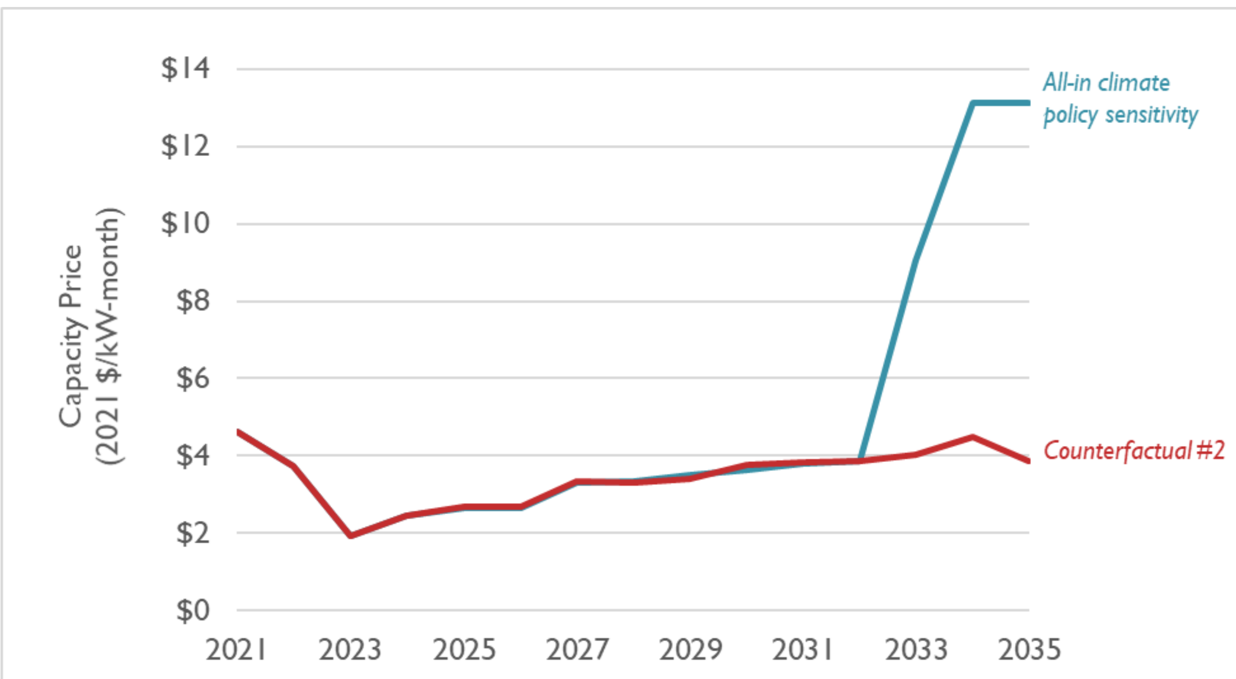
Compared to Counterfactual #2, the 15-year levelized capacity price in the All-In Climate Policy Sensitivity is 42 percent higher (see Table 141 and Figure 60). Capacity prices in the All-In Climate Policy Sensitivity are identical or similar to prices in Counterfactual #2 from FCA 12 through FCA 23, as more clean energy comes online and demand does not diverge substantially. Beginning in FCA 24, the All-In Climate Policy Sensitivity features a faster increase in demand, caused by increased electrification and a switch to winter peaking, resulting in higher prices. See the above section on capacity price results for the No New EE Climate Policy Sensitivity for more information on how capacity price modeling was performed for these winter-peaking years.

Table 141. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #2	AESC 2021 All-In Climate Policy Sensitivity
2021/2022	12	$4.63	$4.63
2022/2023	13	$3.73	$3.73
2023/2024	14	$1.92	$1.92
2024/2025	15	$2.46	$2.46
2025/2026	16	$2.69	$2.64
2026/2027	17	$2.69	$2.65
2027/2028	18	$3.33	$3.29
2028/2029	19	$3.30	$3.33
2029/2030	20	$3.41	$3.49
2030/2031	21	$3.77	$3.62
2031/2032	22	$3.81	$3.79
2032/2033	23	$3.86	$3.87
2033/2034	24	$4.02	$9.04
2034/2035	25	$4.47	$13.13
2035/2036	26	$3.86	$13.13
15-year levelized cost		**$3.45**	**$4.89**
Percent difference			**42%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Figure 60. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)



Cost of RPS compliance

Table 142 shows how the cost of RPS compliance changes in the All-In Climate Policy Sensitivity, relative to Counterfactual #2. Depending on the state and RPS class, costs of compliance in the All-In Climate

Policy Sensitivity are between 0 and 60 percent higher than in Counterfactual #2. This increase in compliance costs is due to increased energy demand, and as a result, increased REC prices and resulting RPS compliance costs.

Table 142. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #2	Class 1/New	v	$3.10	$3.10	$1.31	$5.63	$0.75
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
	Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**
All-In Climate Policy Sensitivity	Class 1/New	$4.78	$4.67	$3.95	$1.69	$9.02	$0.95
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.92	$5.22	$0.03	$2.16
	Total	**$6.12**	**$5.12**	**$10.01**	**$6.91**	**$9.05**	**$3.11**
Percent Difference	Class 1/New	39%	51%	27%	29%	60%	26%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	6%	2%	16%	12%
	Total	**28%**	**44%**	**11%**	**8%**	**60%**	**16%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #2, avoided costs for PTF, NO_X non-embedded, capacity DRIPE, energy DRIPE and cross-DRIPE in the No New EE Climate Policy Sensitivity are either identical or nearly so.

As in the No New EE Climate Policy Sensitivity, we observe large differences between the IRCEP cost and the non-embedded GHG cost based on the marginal abatement cost from the New England electric sector. Compared to the No New EE Climate Policy Sensitivity, non-embedded GHG costs in this sensitivity are lower primarily as a result of lower loads. In this sensitivity, IRCEP drives the addition of only a small amount of incremental renewable capacity before 2029. This produces low costs of compliance in the early years of the study, which are the least-discounted and therefore the most valuable from a levelized perspective.

For more information on why costs under IRCEP differ from costs derived from a New England-derived MAC, see page 313.

Other considerations for modeling climate policy sensitivities

This section focuses on other considerations related to the climate policy sensitivities. These considerations may be useful when developing future AESC analyses.

Energy prices

Except in a few situations described above, we note that energy prices in the climate policy sensitivities closely resemble energy prices in the main counterfactuals. In other words, adding a substantial amount of clean energy to the grid (even above the quantity expected under current legislation and regulations) and increasing electric demand by nearly 20 percent does not substantially change energy prices on annual basis. However, we do note that there are seasonal shifts. In particular, we observe lower summer prices (as more solar depresses energy prices during periods of high insolation) and higher winter prices (as higher levels of building and transportation electrification drive an increased demand for electricity in winter months). As electrification levels continue to increase past 2035, it is possible that we may observe larger changes in energy prices.

In addition, in the No New EE Climate Policy Sensitivity, we observe very low energy prices from the mid-2020s through the early 2030s in Maine. This is caused by a large amount of onshore wind deployments, without corresponding increases in transmission (to link Maine with southern New England) or increased loads in Maine itself (e.g., accelerating deployments of EVs or heat pumps). Future AESC modeling may wish to take these constraints into consideration, as the assumptions used for transmission or load changes may have a substantial impact on energy prices.

Electric sector generation

We observe that implementing the climate policies described above implies that generation from fossil-fired power plants decreases from about 50 TWh in 2020, to about 30 TWh in 2025 to about 20 TWh in 2028 through 2035.

We also note that in years with very high levels of renewables (e.g., the mid-2030s), the model is not always able to reach the IRCEP requirement. For example, in the All-In Climate Policy Sensitivity, we reached 87 percent non-fossil energy in 2035, rather than the 90 percent target. This discrepancy is partly due to wind curtailments and increasing storage demand, as well as non-fossil resources (like nuclear and hydro) being unexpectedly displaced by renewable resources. This observation may in some instances be a modeling artifact, caused by inconsistencies in input assumptions related to weather patterns for renewables and load. In future AESC studies, it may behoove the Study Group to evaluate this phenomenon in more detail.

Finally, the current climate policy sensitivities attribute existing non-emitting generation among the six states at a very high level. As states increasingly deploy polices (like Massachusetts' CES-E or municipal GGES) that require load-serving entities to procure and retire clean energy certificates, this may cause a shift in the IRCEP compliance cost across the states.

Capacity prices and winter peak

In both climate policy sensitivities, we observe that the New England electricity system becomes winter peaking in the early 2030s. This change to winter peaking may necessitate substantive changes to the design of the current capacity market. In the interim, the capacity prices calculated in this analysis represent our best estimate of capacity prices under the current construct. We do modify seasonal capacity credits for solar and wind, which substantially reduces available supply.

Climate policy sensitivity results and marginal abatement costs

Generally speaking, we observe large differences between the IRCEP cost and the non-embedded GHG cost based on the marginal abatement cost from the New England electric sector (e.g., offshore wind). We note that these approaches represent fundamentally different approaches to calculating the cost of abating climate pollution.

- The New England-specific marginal abatement cost derived from the electric sector is equal to the all-in cost of offshore wind, less energy costs. This cost starts immediately in 2021 at a high price, then decreases over time.
- In the climate policy sensitivity, we begin modeling the IRCEP program beginning in 2025. This means there is no cost in the first four years of the study. Over time, this policy results in dozens of TWh of additional clean energy added to the New England system. This incremental clean energy consists of a mix of solar, onshore wind, and offshore wind.

Because of the different approaches used to create these values, results from these two approaches are challenging to compare on an apples-to-apples basis. Some of the major differences include:

- The New England marginal abatement cost approach assumes that avoided costs begin in 2021 and persist throughout the study period. In the climate policy sensitivities, the IRCEP program begins in 2025. This difference is key when comparing costs in levelized terms. Because of the levelization calculations used in summarizing avoided costs in AESC, where values earlier in the analysis are discounted less than values far into the study period, there are at least four "high-worth" near-term years in the climate policy sensitivities where the cost of compliance is $0 per MWh.
- In the climate policy sensitivities, we derate the cost of new entry by each state's share of load that is subject to the IRCEP. For example, in Massachusetts in 2035, we calculate that 86 percent of EDC load is subject to the RPS or similar programs. Because the regional target in this year under IRCEP is 90 percent, we would multiply the cost of new entry by 4 percent. In another example, in Rhode Island in 2035, 100 percent of load is expected to be met with current RPS programs. This means that there is no incremental cost associated with IRCEP, and therefore the compliance cost is zero. In the New England MAC approach, the compliance cost is not derated.
- The cost of new entry differs in the two approaches. In the New England MAC approach, the cost of new entry is based on offshore wind, which has a high cost early in the period that decreases over time. Meanwhile, in the climate policy sensitivities, the cost of new entry is based on a mix of different resources, including solar, onshore wind, and offshore wind.

Separately, we note that the non-embedded GHG cost under IRCEP is also substantially lower than the social cost of carbon recommended in Chapter 8: *Non-Embedded Environmental Costs*. These represent two fundamentally different approaches to calculating the non-embedded GHG cost. (the social cost of carbon is a damage approach, while IRCEP is a marginal abatement cost approach).

Considering costs after 2035

The climate policy sensitivities are modeled in detail from 2021 through 2035, consistent with the detailed modeling horizon used elsewhere in AESC. This limitation means that costs reported in the period after 2035 are extrapolated based on costs from 2031-2035. In years after 2035, electricity markets will likely face a number of new issues that may lead to substantially different avoided costs than are reported with this extrapolation technique.

- In order for the New England states to reach their climate and decarbonization goals, we expect that that levels of building and transportation electrification are likely to increase substantially after 2035. For example, in the All-in climate policy sensitivity, regional loads in 2035 are projected to be 1.3 times higher than today. Massachusetts' *Decarbonization Roadmap* study suggests that electrification would cause 2040 loads to be 1.5 times higher than today. In 2050, loads would be 1.9 times higher. These higher levels of load may lead to increased energy and capacity prices.
- Higher levels of load would also likely increase RPS compliance and IRCEP compliance costs, all else being equal. IRCEP costs may also increase as a result of clean energy requirements increasing 90 percent (e.g., 100 percent by 2050, as is assumed in the *Decarbonization Roadmap* study). The subsection above titled "Electric sector generation" discusses in more detail the challenges of modeling an electricity system with very high levels of renewable penetration, and the impacts on avoided costs associated with these challenges.
- Reaching very high levels of renewable penetration (e.g., 85-100 percent) and electrification may require other investments not currently addressed in the AESC study. For example, this future may involve high levels of investment in transmission and distribution, increased needs for flexible load and long-duration storage, or novel technologies for smaller, hard-to-reach sectors not considered in these sensitivities (e.g., hydrogen or renewable fuels).
- Because capacity costs rise quickly in the early 2030s, the extrapolation techniques used for calculating avoided costs in 2036-2055 for the main AESC analysis yield implausibly high capacity costs in these years.

Other climate policy costs

The costs analyzed in this chapter are primarily focused on electric sector costs. Our analysis does not include any costs or prices associated with building electrification, transportation electrification, or energy efficiency deployment. Our modeled costs in this chapter also do not include any avoided costs related to renewable fuels (like RNG or B100), which may be useful to consider as a complementary avoided cost for building electrification measures alongside the IRCEP price described here.

Finally, our analysis does not include any costs of distribution investments or enhancements, which may be necessary in some areas as building and transportation electrification increases, or, conversely, mitigated by energy efficiency under these same circumstances. The avoided costs associated with this mitigation may be substantial and are not included in our avoided cost calculations.

APPENDIX A: USAGE INSTRUCTIONS

This appendix describes how values post-2035 are extrapolated, how to compute levelization, how to convert between nominal and constant dollars, and how to compare results from this AESC study to previous versions. This appendix also includes a description of the role of energy efficiency programs in the capacity market.

Extrapolation of values post-2035

Many demand-side measures have lifetimes extending past 2035, which requires the extrapolation of avoided cost values for years 2036 through 2055.[345]

In past editions of AESC, authors used the formula as described in Equation 12 to extrapolate costs for each avoided cost category.[346] The resulting growth rate is then applied to values in 2035 to calculate values in 2036. Subsequent years through 2055 are calculated similarly.

Equation 12. Compound annual growth rate (CAGR) formula used in past versions of AESC

$$CAGR = \left(\frac{Avoided\ Cost_{n+4}}{Avoided\ Cost_n}\right)^{\left(\frac{1}{4}\right)} - 1$$

This extrapolation methodology was chosen historically because it relies on values that are "close to" the extrapolated period, under the theory that extrapolated values would be most influenced by more "recent" values (and should be less influenced by values in the early 2020s, for example). However, members of the AESC 2021 Study Group pointed out that because this methodology only relies on two data points, in certain circumstances (i.e., when the 2031 or 2035 values are divergent relative to the rest of the series) this method can produce a very high or very low growth rate. As a result, it may not be suitable for calculating avoided costs post-2035.

The Synapse Team developed a list of pros and cons of the CAGR extrapolation methodology as well as other methodologies, then provided a recommendation for which approach to use.

Compound annual growth rate (CAGR)

A CAGR spanning a five-year period has been the method used for extrapolating non-modeled values in all recent previous AESC studies. But other CAGR periods (e.g., spanning 6 years, 10 years, or something

[345] Program administrators installing measures with long lifetimes in 2022 or later years will utilize avoided costs in 2051 and later.

[346] In past versions of AESC, this has been referred to this as a "Five-year CAGR" since it spans five data years, although it only covers four years of growth.

else) are also possible candidates for use. Table 143 summarizes the main advantages and disadvantages of the CAGR approach.

Table 143. Advantages and disadvantages of CAGR approach

Advantages	Disadvantages
A shorter-term CAGR relies on data points that are closest to the extrapolated period.	Any CAGR relies on two data points. If these data points are outliers relative to the rest of the series, the growth rate may be too low or too high.
This approach has been used historically and is widely recognized and understood.	

Average annual growth rate (AAGR)

The AAGR is a common alternate to the CAGR. AAGR is calculated by determining the annual year-on-year change in the values of a series, then calculating the simple mathematical mean (average) over that set of resulting growth rates. Unlike CAGR, it relies on a set of numbers to inform future values (rather than only two data points). However, AAGR has a drawback of overstating trends in some circumstances. Consider the example shown in Table 144. In this scenario, the series varies between a value of 100 and 110 over a period of 11 years, but returns to 100 in the final year. Because a unit reduction from a high value is a lower percentage than a unit reduction from a low value, the AAGR is 0.5 percent over this time period, whereas a CAGR would produce a growth rate of 0 percent. If annual variability is small, this effect may not substantially bias the resulting AAGR. However, if the annual variability is large in at least some years, the resulting AAGR may be larger than expected.

Table 144. Example of AAGR calculation over a stationary series

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Value	100	110	100	110	100	110	100	110	100	110	100
Annual Growth rate	-	10%	-9%	10%	-9%	10%	-9%	10%	-9%	10%	-9%
AAGR	-	-	-	-	-	-	-	-	-	-	0.5%

As with CAGR, for AAGR there is a choice to make about what period to rely on for forecasting the future (e.g., spanning 6 years, 10 years, or something else). Table 145 summarizes the main advantages and disadvantages of the AAGR approach.

Table 145. Advantages and disadvantages of AAGR approach

Advantages	Disadvantages
AAGR relies on a set of data points (rather than just two as in the CAGR method), which smooths out the resulting growth rate.	AAGR can be biased towards larger changes in values, even if the series is mostly invariant.
This approach is widely used (outside of AESC) and understood.	This approach has not been used in previous AESC studies.

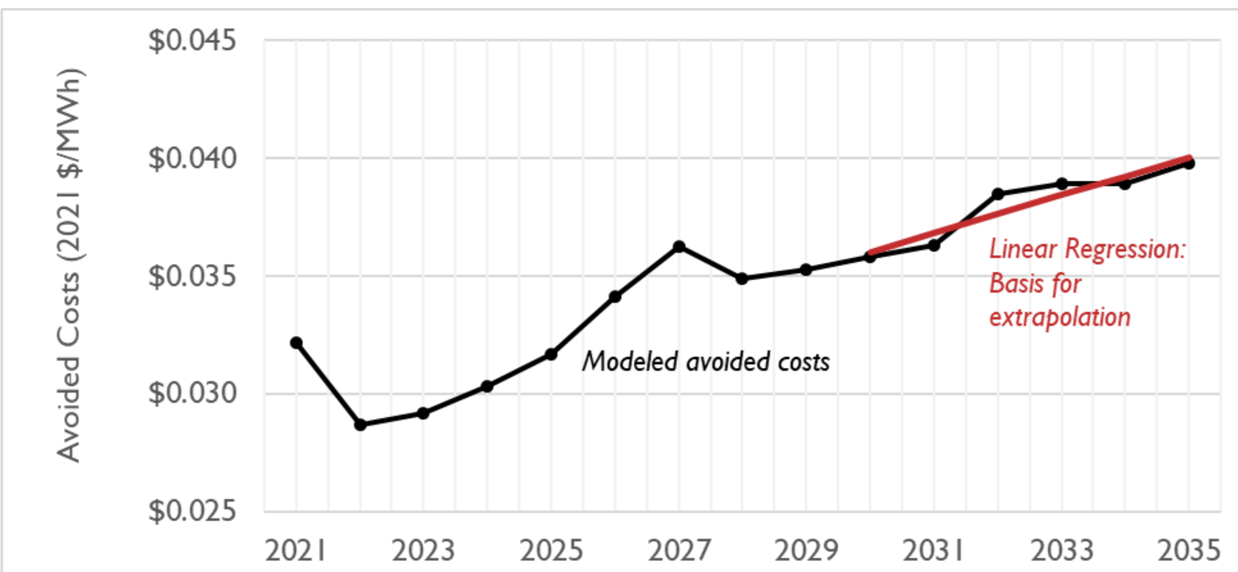
Calculating a growth rate based on a regression

The Synapse Team developed a third extrapolation option aimed at reconciling the following needs:

- The need to extrapolate future values using modeled values that are relatively "near" the extrapolated period
- The need to rely on extrapolate avoided costs that are representative of the recent trend, absent noise in the data

One way to achieve both of these goals is to smooth the values, then calculate the CAGR or AAGR. One smoothing technique is to perform a linear regression over the values in question. Figure 61 depicts a linear regression of the 2030 to 2035 datapoints in an example set of avoided costs. This linear regression creates a basis for extrapolation that is both (a) based on a set of "recent" values and (b) smooths the noise in the series.

Figure 61. Example of linear regression over a short period



We then calculate a CAGR using the first value in the regression and the last value in the regression. Alternately, we could instead calculate the AAGR over the same period (starting with the annual growth rate observed between the second point in the regression and the first point, and so on). For many regressions, these two growth rates will be virtually identical (e.g., within one one-tenth of a percent), with the AAGR being slightly larger than the CAGR due to the regression producing a constant unit change added to smaller, then larger, avoided costs. Table 146 summarizes the advantages and disadvantages of this approach.

Table 146. Advantages and disadvantages of regression-derived growth rate approach

Advantages	Disadvantages
This approach smooths the trend observed over a recent set of data points.	This approach has not been used in previous studies and was derived specifically for AESC.
Resulting CAGR and AAGR will be virtually identical for most series.	

Recommendation for extrapolation

In developing our recommendation, the Synapse Team notes the following:

- The Study Group has expressed a desire for a single extrapolation methodology for use across all avoided cost categories for ease of use.
- The Study Group has expressed a desire for an extrapolation technique to be both (a) based on data from years close to the extrapolation period and (b) be representative of the overall trend during this period (rather than being heavily weighted by one or two outlying data points).
- The “best” extrapolation method should be selected based on the one technique that best meets the needs expressed for extrapolation, rather than the one that produces the best-looking or most reasonable result for a particular avoided cost series.

The Synapse Team recommends the CAGR with regression technique as the extrapolation technique best suited to using recent values that are representative of a number of data points in each avoided cost series. In addition, we recommend increasing the timespan to 2030–2035. The addition of another year covers a period large enough to produce a less-noisy trend. The 2030–2035 time period also continues to represent a period of time that better represents post-2036 trends. The Synapse Team recommends using CAGR rather than AAGR as this method avoids the bias inherent in AAGR related to weighting unit changes applied to larger vs. smaller numbers.[347]

[347] There are two exceptions to this recommendation. First, we estimate capacity price shifts in 2036-2055 (used to calculate capacity DRIPE benefits in these years) by examining the median price shift from 2025 through 2035. A median is used rather than a trend plus CAGR because small year-on-year differences in demand or supply can produce substantial swings in price shifts in one year, followed by a return to the original price shift just one year later. These swings are much larger than any swings observed in other avoided cost inputs, and are an outcome of the stepwise supply function used by ISO New England (and deployed in AESC). This period is chosen because it is the period where capacity prices are projected, rather than based on observed auction data. The second exception is the final avoided cost streams for uncleared measures (e.g., uncleared capacity, uncleared capacity DRIPE). Because avoided costs in these categories vary by measure life, and because they are summed over the entire study period (rather than over the measure life as with all other avoided cost categories), we extrapolate the inputs used for these categories (e.g., capacity clearing prices, loads) but calculate avoided costs explicitly for each year through 2055.

Note that through the use of the *AESC 2021 User Interface* and other appendices, readers of AESC 2021 can calculate their own extrapolated values if their policy context requires some alternate methodology than the one recommended above.

Levelization calculations

The AESC Study presents levelized costs throughout on a 15-year basis; *Appendix B: Detailed Electric Outputs* presents levelized costs over different years. We calculate levelized costs for three different periods:

- 10-year: 2021 to 2030
- 15-year: 2021 to 2035
- 30-year: 2021 to 2050

All levelized costs are calculated using a real discount rate of 0.81 percent.

To calculate levelized costs beyond the three periods documented above, readers of AESC will require (a) a real discount rate (0.81 percent or otherwise specified), (b) the number of years and timeframe over which costs are to be levelized (e.g., 10 years—2021 through 2030 inclusive), and (c) the specific avoided cost values for the relevant reporting region. Equation 13 describes the formula used to estimate a levelized cost within Excel.

Equation 13. Excel formula used for calculating levelized costs

$$Levelized\ cost = -PMT(DiscountRate, NumberOfYears, NPV(DiscountRate, StreamOfCostsWithinPeriod))$$

Converting constant 2021 dollars to nominal dollars

Unless specifically noted, this report presents all dollar values in 2021 constant dollars. To convert constant 2021 dollars into nominal (current) dollars, apply the formula described in Equation 14. Inflator and deflator conversion factors for AESC 2021 are presented in *Appendix E: Common Financial Parameters*.

Equation 14. Nominal-constant dollar conversion

$$Nominal\ Value = \frac{Constant\ Value\ (in\ 2021\ \$)}{Annual\ Conversion\ Factor\ to\ 2021\ \$}$$

Comparisons to previous AESC studies

A reader of the AESC 2021 Study may prepare comparisons of the AESC 20221 Study’s 15-year levelized avoided costs with the 2018 AESC Study’s avoided costs using the following steps:

- Identify the relevant reporting region and costing period
- Obtain the annual values of each avoided cost component from Appendix B in AESC 2021 and AESC 2018 (for the relevant reporting region and costing period)
- Convert the AESC 2018 values from 2018 dollars to 2021 dollars
- Calculate the 15-year levelized cost in 2021 dollars using the AESC 2021 real discount rate (0.81 percent)

APPENDIX B: DETAILED ELECTRIC OUTPUTS

AESC 2021 provides detailed avoided electricity cost projections, both energy and capacity, for each New England state. This appendix provides an overview of and instructions on how to apply those avoided costs. All values can be found in the *AESC 2021 User Interface* (see Appendix F: *User Interface* for more information) and state values are summarized in the standalone Excel file titled "Appendix B."[348]

Structure of Appendix B tables

For each state, Appendix B presents tables with the following avoided costs:

1. Avoided unit cost of electric energy
2. Avoided REC costs to load
3. Avoided non-embedded GHG costs
4. Avoided NO_X costs
5. Energy DRIPE for intrastate and rest-of-pool for 2021 installations
6. Electric Cross-DRIPE
7. Avoided unit cost of electric capacity by demand reduction bidding strategy
8. Capacity DRIPE for intrastate and rest-of-pool for 2021 installations
9. Avoided reliability costs
10. Avoided cost of pooled transmission facilities (PTF)

Illustrative levelized values are provided for each avoided cost.

Appendix B is organized into wholesale values, then retail values. Users typically do not need to use or modify the wholesale values directly, but users should apply values in accordance with state regulations.

Within these two categories, avoided costs are further arranged into avoided energy-based costs (presented in $ per kWh) and avoided capacity-based costs (presented in $ per kW-year).

[348] For comparative, historical purposes, we also estimate avoided costs for two subregions within Connecticut and three subregions within Massachusetts. Avoided costs for these subregions are not materially different from avoided costs for each of two relevant states. This subregional data is only found in the *AESC 2021 User Interface*.

Energy-based avoided costs, $ per kWh

Avoided electric energy costs are presented by year in four costing periods: on-peak winter, off-peak winter, on-peak summer, off-peak summer. ISO New England defines these costing periods as follows:[349]

- Summer on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the months of June–September (1,376 Hours, 15.7 percent of 8,760)[350]
- Summer off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, weekends, and ISO holidays in the months of June–September (1,552 Hours, 17.7 percent of 8,760)
- Winter on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,720 Hours, 31.0 percent of 8,760)
- Winter off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,112 Hours, 35.5 percent of 8,760)

The annual avoided electricity cost for a given year, or set of years, is equal to the hour-weighted average of avoided costs for each of the four costing periods of that year (see Equation 15).

Equation 15. Calculation of annual avoided electricity cost

$$\begin{aligned} &\textit{Annual avoided electricity cost} \\ &\qquad = (15.7\% \times \textit{Summer OnPeak}) + (17.7\% \times \textit{Summer OffPeak}) \\ &\qquad + (31.0\% \times \textit{Winter OnPeak}) + (35.5\% \times \textit{Winter OffPeak}) \end{aligned}$$

The specific wholesale avoided energy costs included in Appendix B are explained below.

- *Wholesale avoided costs of electricity energy*. Annual wholesale electric energy prices are outputted from the EnCompass simulation runs.[351]
- *Wholesale REC costs to load*. Annual avoided REC costs are specific to each state.
- *Wholesale non-embedded GHG and NO_X costs.* Annual estimates of non-embedded CO_2 and NO_X values are provided for each of the four energy costing periods. Non-embedded costs of NO_X are included in Appendix B for the first time in AESC 2021 and

[349] ISO New England. Last accessed March 10, 2021. "Glossary and Acronyms." *Iso-ne.com.* Available at https://www.iso-ne.com/participate/support/glossary-acronyms/.

[350] ISO New England holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

[351] The avoided energy costs are computed for the aggregate load shape in each zone by costing period as described in more detail in Section 4.3. New *England system demand*.

can be included in a program administrator's cost-effectiveness model if desired. These avoided costs are calculated in the same manner as non-embedded carbon costs.

- *Wholesale energy DRIPE*. Separate projections are provided for wholesale intrastate and rest-of-pool energy DRIPE.[352] Users should apply energy DRIPE values in accordance with relevant state regulations governing treatment of energy DRIPE. For example, Massachusetts only considers intrastate DRIPE benefits, whereas Rhode Island considers both intrastate and rest-of-pool DRIPE benefits.
- *Wholesale cross-DRIPE.* Annual wholesale electric cross-DRIPE values include both electric-gas cross-DRIPE and electric-gas-electric cross-DRIPE, which represents the benefits from a reduction in the quantity of electricity that reduces gas consumption and that subsequently reduces electric prices. Users should treat the avoided costs for electric cross-DRIPE similarly to energy DRIPE.

Capacity-based avoided costs, $ per kW-year

Most capacity-based avoided cost components—including wholesale avoided unit cost of electric capacity, wholesale capacity DRIPE, and reliability—are separated into cleared, uncleared, and weighted average values.

The *cleared* capacity columns provide estimates for FCA capacity prices reported on a calendar year basis. ISO New England generally reports capacity prices based on power-years (June 1 to May 31).

The *uncleared* capacity columns provide estimates for capacity based on uncleared capacity or unbid capacity avoided through energy efficiency measures. The values are multiplied by the capacity price load effect and reserve margin percentages. Because FCA auctions are set three years in advance of the actual delivery year, avoided capacity not bid into an FCA will not impact ISO New England's determination of forecasted peak until 2026 for measures installed in 2021.

Wholesale capacity DRIPE projections are provided for intrastate and rest-of-pool energy DRIPE for installation year 2021. Users should apply capacity DRIPE values in accordance with relevant state regulations governing treatment of capacity DRIPE.

Avoided cost for PTF is based on costs allocated to LSEs from ISO New England. This is the only capacity-based avoided cost that is not separated into cleared, uncleared, and weighted average values, because it is not part of the FCM. Utilities that use avoided PTF costs should include only local transmission investments (those not eligible for PTF treatment) in their own avoided transmission cost analyses.

In the *AESC 2021 User Interface*, users may specify a percentage of measures that are cleared in the FCM. This percentage is then used to calculate a weighted average avoided cost for cleared and uncleared capacity, cleared and uncleared capacity DRIPE, and cleared and uncleared reliability. The weighted average is based on a simplified bidding strategy consisting of *x* percent of demand reductions

[352] DRIPE vintage years are available for 2021 through 2025 within the *AESC 2021 User Interface*.

from measures in each year bid (cleared) into the FCA for that year and the remaining 1-*x* percent not bid (uncleared) into any FCA. The default value for *x* is 50 percent.

How to convert wholesale avoided costs to retail avoided costs

AESC estimates avoided electric costs at the wholesale level, meaning reductions at power plants or energy markets. The *AESC 2021 User Interface* and Appendix B Excel workbooks allow users to convert the wholesale values to retail values. Retail avoided costs represent reductions at the customer meter or end-use level, and they are meant to approximate the price customers see on utility bills.

Depending on the avoided cost, two adjustment factors are applied to convert from wholesale to retail values: (1) a factor for transmission and distribution losses, and (2) a wholesale risk premium. Both factors are described in detail below. These adjustments gross up wholesale values, leading to retail values that are greater than wholesale values.

In general, the formula for converting from wholesale to retail is shown in Equation 16.

Equation 16. Converting from wholesale to retail avoided costs

$$\begin{aligned} &\textit{Avoided retail cost} \\ &\qquad = (\textit{avoided wholesale cost}) \times (1 + \textit{losses}) \times (1 + \textit{wholesale risk premium}) \end{aligned}$$

Wholesale risk premium

The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary-service. This is because retail suppliers incur various market risks when they set contract prices in advance of supply delivery. In AESC, this premium over wholesale prices is called the *wholesale risk premium*, and the default assumption is that retail prices are 8 percent greater than wholesale prices.

Types of risk

The wholesale risk premium accounts for multiple risks. First, there is the retail supplier's cost to mitigate cost risks. Retail suppliers mitigate some risk by hedging their costs in advance, but there is still uncertainty in the final price borne by the supplier. This includes cost risk from hourly energy balancing, ancillary services, and uplift.

The larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters, LSEs may need to procure additional energy at shortage prices, while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles.

In addition, the suppliers for utility standard-service offers run risks related to customer migration. Customers may migrate from the utility's standard offer service to competitive supply, presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss. Alternatively, customers may switch from competitive supply to the utility's standard offer service at times of high market prices, forcing the supplier to purchase additional power in a high-cost market.

Estimating the wholesale risk premium

Estimates of the appropriate premium range from less than 5 percent to around 10 percent, based on analyses of confidential supplier bids—primarily in Massachusetts, Connecticut, and Maryland—to which the Synapse Team or sponsors have been privy.[353] Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers' willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels tend to see the resulting costs incorporated into the adders in supplier bids.[354] AESC 2021 uses a wholesale risk premium of 8 percent to reflect these dynamics.

AESC 2021 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[355]

The risk premium is a separate input to the avoided-cost spreadsheet. Therefore, program administrators will be able to input whatever level of risk premium they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.

Members of the Study Group have inquired if a similar wholesale risk premium could be applied for natural gas efficiency programs. Natural gas marketers also undertake contracts of varying durations for future delivery and account for risks in their retail pricing. The current scope of AESC 2021 does not include the development of a wholesale risk premium for natural gas, but such work could be included in future AESC studies or updates to this study.

[353] Note that these bids are confidential and cannot be made public.

[354] The default value for Vermont is set in accordance with guidance from the Vermont PUC, which also specifies a default value for municipal utilities. These utilities typically either procure a basket of generation resources or contract for bundled service from suppliers.

[355] Capacity costs present a different risk profile than energy costs. With the FCM, suppliers have a good estimate of the capacity price three years in advance and of the capacity requirement for customers about one year in advance. Reconfiguration auctions may affect the capacity charges, but the change in average costs is likely to be small. On the other hand, since suppliers generally charge a dollars-per-MWh rate, and energy sales are subject to variation, the supplier retains some risk of under-recovery of capacity costs. There is no way to determine the extent to which an observed risk premium in bundled prices reflects adders on energy, capacity, ancillary services, RPSs, and other factors. Given the uncertainty and variability in the overall risk premium, we do not believe that differentiating between energy and capacity premiums is warranted. We thus apply the retail premium uniformly to both energy and capacity values.

Transmission and distribution losses

There is a loss of electricity between a generating unit and ISO New England's delivery points. Therefore, a kilowatt load reduction at the ISO New England's delivery points reduces the quantity of electricity that a generator has to produce by one kilowatt plus the additional quantity that would have been required to compensate for losses. These losses occur on both the transmission and distribution systems and apply to both energy and capacity avoided costs.[356]

When converting from wholesale to retail values, program administrators can use the default T&D loss value in AESC of 8 percent, or program administrators can use their own custom T&D loss factors.

AESC T&D losses

AESC converts avoided costs from wholesale to retail values assuming marginal losses of 9 percent for energy (i.e., all avoided cost categories that are described in terms of $ per kWh) and 16 percent for peak demand (i.e., all avoided cost categories that are described in terms of $ per kW-year). Table 147 displays the recommended loss factors, along with the average factors from which they are derived. We note that previous editions of AESC have typically recommended a loss factor of 8 percent be applied to all avoided cost categories.[357] However, this loss factor is average (rather than marginal) and focused on peak hours (rather than all hours). As a result, we have updated the recommended loss factors in AESC 2021. See Section 4.3 *New England system demand* for more discussion on deriving marginal loss factors.

Table 147. Loss factors recommended for use in AESC 2021

	Energy	Peak Demand
Average	6% *(a)*	8% *(c)*
Marginal *Recommended in AESC 2021*	9% *(b)*	16% *(d)*

Sources: (a) https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf, slide 25; (b) 1.5 x 6%, per 2011 RAP paper; (c) ISO New England Market Rules, Section III.13.1.4.1.1.6.(a); (d) 2 x 8%, per 2011 RAP paper.

Custom T&D losses

If a program administrator chooses to apply custom T&D loss values, it needs to consider three types of losses: distribution losses, transmission non-PTF losses, and transmission PTF losses. Below, we estimate

[356] The forecast of capacity costs from the FCM do not reflect these losses; therefore forecasted capacity costs should be adjusted to account for them.

[357] Note that this 8 percent value includes both transmission losses (2.5 percent) and distribution losses (5.5 percent). ISO New England. October 10, 2019. *Transmission planning Technical Guide.* Available at https://www.iso-ne.com/static-assets/documents/2017/03/transmission_planning_techincal_guide_rev6.pdf.

PTF losses and describe the need for program administrators to derive their own non-PTF costs. These two components could then be added to custom distribution losses values, perhaps developed using the guidance in Section 10.4: *Localized value of avoided T&D*.

PTF losses

ISO New England does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. ISO New England does release hourly values for system load and non-PTF demand that enable to us to estimate PTF losses.[358] On average, system PTF losses between 2010 and 2020 are 1.6 percent. This is the same number described in AESC 2018.

PTF losses probably vary among zones, because losses in any zone depend both on loads in that zone and flows into and out of that zone to the rest of the region. However, marginal losses by zone could not be identified using the available data provided by ISO New England in December 2020, and it would be difficult to estimate from historical data anyway. Therefore, we use average losses for AESC 2021.

Non-PTF losses

AESC does not recommend a calculation for non-PTF losses at this time. Utilities who wish to develop a custom T&D factor should examine their own data and formulate their own non-PTF losses as appropriate. These non-PTF losses include losses over the non-PTF transmission substations and lines to distribution substations.

Applying wholesale to retail factors

Table 148 summarizes which retail factors are applied when converting wholesale avoided cost to retail avoided costs. Losses apply to all avoided costs.[359] Losses are applied to avoided capacity costs to be consistent with how generation capacity is procured or avoided.

The wholesale risk premium is applied to energy values except non-embedded values and to uncleared capacity values. The wholesale risk premium does not apply to non-embedded values because, by definition, these costs are not embedded in electricity prices; therefore retail suppliers do not include these costs in supply contracts. The wholesale risk premium does not apply to cleared capacity values because resources cleared in the FCM receive FCM prices.

Avoided PTF costs, represent avoided infrastructure investments, which would not be impacted by line losses or wholesale market risks.

[358] ISO New England defines system load as the sum of generation and net interchange, minus pumping load, and non-PTF demand. ISO New England uses the term “non-PTF demand” for the load delivered into the networks of distribution utilities. Losses on the PTF system are thus the difference between the system load and non-PTF demand.

[359] This includes avoided PTF costs. Avoided PTF costs are calculated on the basis of dollars per *generating* kW. In order to be applied to retail kW savings, they must be increased by a loss factor.

Table 148. Wholesale to retail factors by avoided cost category

Avoided cost categories	Losses	Wholesale Risk Premium
Electric energy, energy DRIPE, cross-DRIPE	✓	✓
Non-embedded GHG, non-embedded NOx	✓	
Cleared capacity, capacity DRIPE, reliability	✓	
Uncleared capacity, capacity DRIPE, reliability	✓	✓
PTF losses	✓	

Guide to applying the avoided costs

AESC 2021 allows users to specify certain inputs as well as to choose which of the avoided cost components to include in their analyses. The retail avoided costs are calculated using the following default values:

1. Wholesale risk premium: 8 percent[360]
2. Losses: 9 percent for dollar-per-kWh values and 16 percent for dollar-per-kW values[361]
3. Real discount rate: 0.81 percent

Users may insert their own values for these input assumptions. If a user wishes to specify a different value for any of the inputs, the user should enter the *new* value directly in the Appendix B Excel workbook. The calculations in the worksheet are linked to these values and new avoided costs will be calculated automatically on the "User Results" page.

[360] The wholesale risk premium for Vermont is 11.1 percent per Vermont DPS. See Appendix A for a more detailed discussion of the wholesale risk premium.

[361] Each program administrator should obtain or calculate the losses applicable to its specific system as described in Chapter 10 on avoided T&D costs.

APPENDIX C: DETAILED NATURAL GAS OUTPUTS

The following appendix provides projections of avoided natural gas costs by year, and by end-use. It also includes projections of natural gas supply DRIPE and natural gas cross-DRIPE values by year, and by end-use. Values are also provided in the standalone Excel workbook titled "Appendix C."

Avoided natural gas costs by end-use

Table 150 through Table 154 include forecasts of avoided natural gas costs by year and end-use for three New England sub-regions: southern New England (Connecticut, Rhode Island, Massachusetts), northern New England (New Hampshire, Maine) and Vermont. The avoided cost by end-use is shown two ways: first, as the avoided cost of the gas sent out by the LDC (i.e., the avoided citygate cost), and second, as the avoided cost of the gas sent out by the LDC plus the avoidable distribution cost (i.e., the avoidable retail margin).

The tables show avoided costs for the following end-uses: Residential non-heating, water heating, heating, and all; Commercial & Industrial non-heating, heating, and all; and all retail end-uses.

- Non-heating columns include values related to year-round end-uses with generally constant gas use throughout the year.
- Heating value columns include values related to heating end-uses in which gas use is high during winter months.
- When determining the cost-effectiveness of a program or measure, users should choose the appropriate column to determine the avoided cost values for each program and/or measure.

As mentioned above, Table 150 through Table 154 contain two types of avoided natural gas costs by end-use and sub-region: the first assumes no avoided retail margin, and the second assumes some amount of avoided retail margins. Program administrators must determine if their LDC has avoidable LDC margins and should pick the appropriate value stream accordingly.

Natural gas supply and cross-fuel DRIPE

Table 155 through Table 160 include forecasts of natural gas supply and cross-fuel DRIPE by end-use and costing period. This is shown by year and by state, as well as for the whole of New England. New in AESC 2021, we also display both zone-on-zone and zone-on-rest-of-pool (ROP) values.[362]

[362] Previous versions of AESC directed users of the study to calculate zone-on-Rest-of-Pool values on their own, by subtracting the state values from the New England-wide value. We now present these values separately and explicitly for the reader's convenience.

Column 1 of each of these tables shows gas supply DRIPE for measures installed in 2021. Program administrators can use the value by year from this column and apply it to the MMBtu of gas reduction from efficiency programs and measures throughout the lifetime of the program or measure. An analogous value for zone-on-Rest-of-Pool DRIPE appears in Column 10.

Columns 2 through 9 show gas-electric (G-E) cross-fuel DRIPE by costing period and load segment for each state. Program administrators can use the value by year from these columns and apply them to the MMBtu of gas reduction from the relevant costing period and load segment. These values are calculating using the end-use share assumptions depicted in Table 149.[363]

Table 149. End-use and sector share assumptions used to calculate G-E cross-DRIPE

Sector	End-Use	Share of Sector	Share of Total Consumption
Residential	Non heating	6%	
Residential	Hot water	27%	40%
Residential	Heating	67%	
Commercial & Industrial	Non heating	27%	60%
Commercial & Industrial	Heating	73%	

Note: DRIPE effects for "Non Heating" and "Hot Water" in residential are identical. They are reported separately to facilitate formulas in many program administrators' benefit-cost models. Conversely, commercial & industrial "Non heating" includes hot water measures, but are combined to facilitate their use in the benefit-cost models.

An analogous set of values are shown for zone-on-Rest-of-Pool DRIPE in Columns 11 through 18.

Avoided natural gas costs by costing period

Avoided natural gas costs are shown in Table 161 and Table 162 for each of the six costing periods. The values for each costing period are the annual cost per MMBtu for the gas supply resource that is the lowest-cost option to supply that type of load. These values are multiplied by the percentage shares for the representative load shapes to derive the avoided costs by end-use that are presented in Table 150 and Table 153. Note, for example, that because the load shape for residential non-heating is 100 percent baseload, the avoided costs for Residential Non-heating in Table 150 and the Baseload values in Table 161 are the same.

The values in Table 161 and Table 162 can be used to calculate the avoided natural gas costs for programs that reduce gas use during specific periods during the year. For example, the Baseload

363 In AESC 2021, the "share of sector" percentages are calculated by using New England-specific data from EIA's 2015 RECS survey (EIA. Last accessed March 10, 2021. *2015 RECS Survey.* Available at https://www.eia.gov/consumption/residential/data/2015/c&e/ce4.2.xlsx.)

"Share of total consumption" percentages are calculated based on 2014-2019 data for all six New England states obtained from EIA. "Natural Gas Consumption by End Use." *Eia.gov*. Available at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SME_a.htm.

Note that prior editions of AESC utilized data supplied by National Grid.

avoided cost would be applied to a reduction in gas use (in MMBtu) that is spread equally over all days of the year. The Highest 10 Days avoided cost would be applied to a reduction in gas use that occurs only during the 10 days of highest gas use. The Winter values would be used to calculate the avoided natural gas costs for a program that reduces gas use over the November through March winter season (i.e., more than 90 days, and up to 151 days each year).

Table 150. Avoided cost of gas to retail customers by end-use for southern New England (SNE) assuming no avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	4.45	5.21	6.92	6.21	5.29	6.42	5.92	6.07
2022	4.24	5.11	7.08	6.26	5.20	6.50	5.93	6.11
2023	4.03	4.90	6.84	6.03	4.98	6.27	5.71	5.88
2024	4.35	5.22	7.17	6.35	5.30	6.60	6.03	6.20
2025	4.41	5.28	7.22	6.41	5.36	6.65	6.09	6.26
2026	4.52	5.38	7.31	6.51	5.46	6.75	6.19	6.36
2027	4.58	5.43	7.36	6.56	5.52	6.80	6.24	6.41
2028	4.72	5.58	7.50	6.70	5.66	6.94	6.38	6.55
2029	4.85	5.70	7.62	6.82	5.79	7.06	6.50	6.67
2030	4.91	5.76	7.67	6.87	5.84	7.11	6.56	6.73
2031	4.92	5.77	7.67	6.88	5.86	7.12	6.57	6.73
2032	4.99	5.84	7.73	6.94	5.92	7.18	6.63	6.80
2033	5.06	5.90	7.79	7.00	5.98	7.24	6.69	6.86
2034	5.08	5.92	7.80	7.02	6.01	7.25	6.71	6.87
2035	5.09	5.93	7.80	7.02	6.01	7.25	6.71	6.88
2036	5.14	5.97	7.83	7.05	6.05	7.29	6.75	6.91
2037	5.18	6.01	7.86	7.09	6.09	7.32	6.78	6.95
2038	5.22	6.05	7.90	7.13	6.13	7.35	6.82	6.98
2039	5.27	6.09	7.93	7.16	6.17	7.39	6.86	7.02
2040	5.31	6.13	7.96	7.20	6.21	7.42	6.89	7.06
2041	5.36	6.17	7.99	7.23	6.25	7.46	6.93	7.09
2042	5.40	6.21	8.03	7.27	6.30	7.49	6.97	7.13
2043	5.45	6.25	8.06	7.31	6.34	7.53	7.01	7.17
2044	5.50	6.29	8.09	7.34	6.38	7.56	7.05	7.20
2045	5.54	6.34	8.13	7.38	6.42	7.60	7.08	7.24
2046	5.59	6.38	8.16	7.42	6.46	7.64	7.12	7.28
2047	5.64	6.42	8.19	7.45	6.51	7.67	7.16	7.32
2048	5.69	6.46	8.23	7.49	6.55	7.71	7.20	7.36
2049	5.73	6.51	8.26	7.53	6.59	7.74	7.24	7.39
2050	5.78	6.55	8.29	7.57	6.64	7.78	7.28	7.43
2051	5.83	6.59	8.33	7.60	6.68	7.82	7.32	7.47
2052	5.88	6.64	8.36	7.64	6.72	7.85	7.36	7.51
2053	5.93	6.68	8.40	7.68	6.77	7.89	7.40	7.55
2054	5.98	6.73	8.43	7.72	6.81	7.93	7.44	7.59
2055	6.03	6.77	8.47	7.76	6.86	7.97	7.48	7.63
Levelized (2021–2030)	4.50	5.35	7.26	6.47	5.44	6.70	6.15	6.32
Levelized (2021–2035)	4.67	5.52	7.42	6.63	5.60	6.86	6.31	6.48
Levelized (2021–2050)	5.03	5.86	7.72	6.94	5.95	7.17	6.64	6.80

Table 151. Avoided cost of gas to retail customers by end-use for southern New England (SNE) assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	5.41	6.17	8.30	7.56	6.07	7.82	7.35	7.43
2022	5.20	6.07	8.47	7.63	5.98	7.91	7.39	7.48
2023	4.99	5.86	8.23	7.40	5.76	7.68	7.16	7.26
2024	5.31	6.18	8.55	7.72	6.08	8.00	7.48	7.58
2025	5.37	6.24	8.61	7.78	6.14	8.06	7.54	7.64
2026	5.48	6.34	8.70	7.87	6.24	8.15	7.64	7.73
2027	5.54	6.39	8.75	7.92	6.30	8.20	7.69	7.78
2028	5.68	6.53	8.89	8.06	6.44	8.34	7.83	7.92
2029	5.80	6.66	9.01	8.19	6.57	8.47	7.95	8.05
2030	5.87	6.72	9.06	8.24	6.62	8.52	8.01	8.10
2031	5.88	6.73	9.06	8.25	6.64	8.52	8.01	8.11
2032	5.95	6.79	9.12	8.31	6.70	8.58	8.08	8.17
2033	6.02	6.86	9.18	8.37	6.76	8.64	8.13	8.23
2034	6.04	6.88	9.19	8.38	6.79	8.66	8.15	8.24
2035	6.05	6.89	9.19	8.38	6.79	8.66	8.15	8.25
2036	6.10	6.93	9.22	8.42	6.83	8.69	8.19	8.28
2037	6.14	6.97	9.25	8.45	6.87	8.73	8.22	8.32
2038	6.18	7.01	9.28	8.49	6.91	8.76	8.26	8.35
2039	6.23	7.05	9.31	8.52	6.95	8.80	8.30	8.39
2040	6.27	7.09	9.35	8.56	6.99	8.83	8.33	8.42
2041	6.32	7.13	9.38	8.59	7.03	8.86	8.37	8.46
2042	6.36	7.17	9.41	8.63	7.07	8.90	8.41	8.49
2043	6.41	7.21	9.44	8.66	7.11	8.93	8.44	8.53
2044	6.45	7.25	9.48	8.70	7.16	8.97	8.48	8.57
2045	6.50	7.29	9.51	8.74	7.20	9.00	8.52	8.60
2046	6.54	7.33	9.54	8.77	7.24	9.04	8.55	8.64
2047	6.59	7.38	9.58	8.81	7.28	9.08	8.59	8.68
2048	6.64	7.42	9.61	8.84	7.32	9.11	8.63	8.71
2049	6.69	7.46	9.64	8.88	7.37	9.15	8.67	8.75
2050	6.73	7.50	9.68	8.92	7.41	9.18	8.70	8.79
2051	6.78	7.55	9.71	8.95	7.45	9.22	8.74	8.83
2052	6.83	7.59	9.74	8.99	7.50	9.26	8.78	8.86
2053	6.88	7.64	9.78	9.03	7.54	9.29	8.82	8.90
2054	6.93	7.68	9.81	9.07	7.58	9.33	8.86	8.94
2055	6.98	7.72	9.85	9.10	7.63	9.37	8.89	8.98
Levelized (2021–2030)	5.46	6.31	8.65	7.83	6.22	8.11	7.60	7.69
Levelized (2021–2035)	5.63	6.48	8.81	7.99	6.38	8.27	7.76	7.85
Levelized (2021–2050)	5.99	6.82	9.11	8.31	6.72	8.58	8.08	8.17

Table 152. Avoided cost of gas to retail customers by end-use for northern New England (NNE) assuming no avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	4.28	5.13	7.04	6.24	5.21	6.48	5.93	6.10
2022	4.07	4.98	7.04	6.18	5.07	6.43	5.84	6.02
2023	3.86	4.76	6.79	5.95	4.85	6.19	5.60	5.79
2024	4.18	5.08	7.12	6.27	5.17	6.51	5.93	6.11
2025	4.25	5.15	7.17	6.33	5.24	6.57	5.99	6.17
2026	4.36	5.25	7.26	6.42	5.34	6.66	6.08	6.26
2027	4.42	5.30	7.30	6.47	5.39	6.71	6.13	6.31
2028	4.56	5.45	7.44	6.61	5.54	6.85	6.27	6.45
2029	4.69	5.57	7.56	6.73	5.66	6.97	6.40	6.57
2030	4.75	5.63	7.61	6.78	5.72	7.02	6.45	6.63
2031	4.77	5.64	7.61	6.79	5.73	7.02	6.46	6.64
2032	4.84	5.71	7.67	6.85	5.80	7.08	6.52	6.70
2033	4.91	5.77	7.72	6.91	5.86	7.14	6.58	6.76
2034	4.94	5.80	7.73	6.93	5.89	7.15	6.60	6.77
2035	4.95	5.80	7.73	6.93	5.89	7.15	6.60	6.78
2036	5.00	5.84	7.76	6.96	5.93	7.19	6.64	6.81
2037	5.04	5.89	7.79	7.00	5.98	7.22	6.68	6.85
2038	5.09	5.93	7.82	7.03	6.02	7.25	6.71	6.88
2039	5.14	5.97	7.85	7.07	6.06	7.29	6.75	6.92
2040	5.18	6.01	7.88	7.10	6.10	7.32	6.79	6.95
2041	5.23	6.05	7.91	7.14	6.14	7.35	6.82	6.99
2042	5.28	6.10	7.94	7.17	6.18	7.39	6.86	7.03
2043	5.33	6.14	7.97	7.21	6.23	7.42	6.90	7.06
2044	5.38	6.18	8.00	7.24	6.27	7.45	6.94	7.10
2045	5.43	6.22	8.03	7.28	6.31	7.49	6.97	7.14
2046	5.48	6.27	8.07	7.32	6.36	7.52	7.01	7.17
2047	5.53	6.31	8.10	7.35	6.40	7.56	7.05	7.21
2048	5.58	6.36	8.13	7.39	6.45	7.59	7.09	7.25
2049	5.63	6.40	8.16	7.43	6.49	7.63	7.13	7.29
2050	5.68	6.45	8.19	7.46	6.53	7.66	7.17	7.33
2051	5.73	6.49	8.22	7.50	6.58	7.70	7.21	7.36
2052	5.79	6.54	8.26	7.54	6.63	7.73	7.25	7.40
2053	5.84	6.58	8.29	7.58	6.67	7.77	7.29	7.44
2054	5.89	6.63	8.32	7.61	6.72	7.81	7.33	7.48
2055	5.95	6.68	8.35	7.65	6.76	7.84	7.37	7.52
Levelized (2021–2030)	4.34	5.22	7.23	6.39	5.31	6.63	6.06	6.24
Levelized (2021–2035)	4.51	5.39	7.38	6.55	5.48	6.79	6.22	6.39
Levelized (2021–2050)	4.89	5.74	7.65	6.86	5.83	7.08	6.53	6.71

Table 153. Avoided cost of gas to retail customers by end-use for northern New England (NNE) assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	5.24	6.09	8.43	7.61	5.99	7.89	7.38	7.47
2022	5.03	5.94	8.43	7.56	5.85	7.84	7.30	7.40
2023	4.82	5.72	8.18	7.32	5.63	7.60	7.06	7.17
2024	5.14	6.04	8.50	7.64	5.95	7.92	7.39	7.49
2025	5.21	6.11	8.55	7.70	6.02	7.97	7.45	7.55
2026	5.31	6.21	8.64	7.79	6.12	8.07	7.54	7.64
2027	5.38	6.26	8.69	7.84	6.17	8.12	7.59	7.69
2028	5.52	6.41	8.83	7.98	6.32	8.25	7.73	7.83
2029	5.65	6.53	8.94	8.10	6.44	8.37	7.85	7.95
2030	5.71	6.59	8.99	8.15	6.50	8.42	7.90	8.00
2031	5.73	6.60	8.99	8.16	6.51	8.43	7.91	8.01
2032	5.80	6.67	9.05	8.22	6.58	8.49	7.97	8.07
2033	5.87	6.73	9.11	8.28	6.64	8.55	8.03	8.13
2034	5.90	6.76	9.12	8.29	6.67	8.56	8.05	8.15
2035	5.91	6.76	9.11	8.29	6.67	8.56	8.05	8.15
2036	5.96	6.80	9.14	8.33	6.71	8.59	8.08	8.18
2037	6.00	6.85	9.17	8.36	6.75	8.63	8.12	8.22
2038	6.05	6.89	9.20	8.39	6.80	8.66	8.15	8.25
2039	6.10	6.93	9.23	8.43	6.84	8.69	8.19	8.29
2040	6.14	6.97	9.26	8.46	6.88	8.73	8.23	8.32
2041	6.19	7.01	9.30	8.50	6.92	8.76	8.26	8.36
2042	6.24	7.05	9.33	8.53	6.96	8.79	8.30	8.39
2043	6.28	7.10	9.36	8.57	7.01	8.83	8.33	8.43
2044	6.33	7.14	9.39	8.60	7.05	8.86	8.37	8.46
2045	6.38	7.18	9.42	8.64	7.09	8.89	8.41	8.50
2046	6.43	7.22	9.45	8.67	7.13	8.93	8.44	8.53
2047	6.48	7.27	9.48	8.71	7.18	8.96	8.48	8.57
2048	6.53	7.31	9.51	8.74	7.22	9.00	8.52	8.61
2049	6.58	7.36	9.54	8.78	7.26	9.03	8.55	8.64
2050	6.63	7.40	9.58	8.81	7.31	9.07	8.59	8.68
2051	6.68	7.44	9.61	8.85	7.35	9.10	8.63	8.72
2052	6.73	7.49	9.64	8.89	7.40	9.14	8.67	8.75
2053	6.78	7.53	9.67	8.92	7.44	9.17	8.70	8.79
2054	6.84	7.58	9.70	8.96	7.49	9.21	8.74	8.83
2055	6.89	7.62	9.73	9.00	7.53	9.24	8.78	8.87
Levelized (2021–2030)	5.30	6.18	8.61	7.76	6.09	8.04	7.51	7.61
Levelized (2021–2035)	5.47	6.35	8.76	7.92	6.26	8.19	7.67	7.77
Levelized (2021–2050)	5.85	6.70	9.04	8.22	6.61	8.49	7.98	8.08

Table 154. Avoided cost of gas to retail customers by end-use for Vermont assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential			
	Design Day 1	*Peak Days 9*	*Remaining Winter 141*	*Shoulder / Summer 214*
2021	554.38	15.27	3.39	3.03
2022	554.43	15.39	3.43	3.07
2023	554.47	17.05	3.48	3.12
2024	555.04	17.09	4.05	3.68
2025	555.37	17.17	4.37	4.01
2026	555.71	17.28	4.72	4.35
2027	556.03	16.97	5.03	4.67
2028	556.42	17.20	5.43	5.07
2029	556.80	17.31	5.81	5.44
2030	557.10	17.65	6.11	5.75
2031	557.14	17.61	6.15	5.79
2032	557.22	17.65	6.23	5.87
2033	557.30	17.53	6.31	5.95
2034	557.34	17.78	6.35	5.99
2035	557.36	17.57	6.37	6.01
2036	557.42	17.57	6.43	6.07
2037	557.48	17.57	6.49	6.12
2038	557.53	17.57	6.55	6.18
2039	557.59	17.57	6.61	6.24
2040	557.65	17.57	6.67	6.30
2041	557.70	17.57	6.73	6.36
2042	557.76	17.57	6.79	6.43
2043	557.82	17.56	6.85	6.49
2044	557.87	17.56	6.91	6.55
2045	557.93	17.56	6.97	6.61
2046	557.99	17.56	7.04	6.68
2047	558.04	17.56	7.10	6.74
2048	558.10	17.56	7.17	6.81
2049	558.16	17.56	7.23	6.87
2050	558.21	17.56	7.30	6.94
2051	558.27	17.56	7.36	7.01
2052	558.33	17.56	7.43	7.07
2053	558.38	17.56	7.50	7.14
2054	558.44	17.56	7.57	7.21
2055	558.50	17.56	7.63	7.28
Levelized (2021–2030)	555.55	16.82	4.56	4.20
Levelized (2021–2035)	556.10	17.08	5.11	4.75
Levelized (2021–2050)	552.49	17.51	11.15	13.51

Table 155. Intrastate gas supply DRIPE and gas cross-DRIPE for Connecticut (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.02	1.21	1.21	2.21	1.88	1.21	1.21	1.21	1.48
2022	0.01	0.36	0.36	0.67	0.57	0.36	0.67	0.59	0.58	0.03	1.82	1.82	3.33	2.84	1.82	1.82	1.82	2.23
2023	0.01	0.44	0.44	0.81	0.68	0.44	0.81	0.71	0.70	0.03	2.08	2.08	3.80	3.24	2.08	2.08	2.08	2.54
2024	0.01	0.35	0.35	0.64	0.55	0.35	0.64	0.56	0.56	0.03	1.68	1.68	3.08	2.62	1.68	1.68	1.68	2.06
2025	0.01	0.24	0.24	0.45	0.38	0.24	0.45	0.39	0.39	0.03	1.43	1.43	2.61	2.23	1.43	1.43	1.43	1.75
2026	0.01	0.17	0.17	0.32	0.27	0.17	0.32	0.28	0.28	0.03	0.98	0.98	1.78	1.52	0.98	0.98	0.98	1.20
2027	0.01	0.12	0.12	0.21	0.18	0.12	0.21	0.19	0.19	0.03	0.61	0.61	1.09	0.93	0.61	0.61	0.61	0.74
2028	0.01	0.09	0.09	0.16	0.14	0.09	0.16	0.14	0.14	0.03	0.43	0.43	0.76	0.65	0.43	0.43	0.43	0.52
2029	0.01	0.06	0.06	0.10	0.08	0.06	0.10	0.08	0.08	0.03	0.27	0.27	0.46	0.39	0.27	0.27	0.27	0.32
2030	0.01	0.03	0.03	0.05	0.04	0.03	0.05	0.04	0.04	0.03	0.12	0.12	0.19	0.17	0.12	0.12	0.12	0.14
2031	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.03	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01
2032	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.01	0.21	0.21	0.39	0.33	0.21	0.39	0.34	0.34	0.03	1.08	1.08	1.96	1.67	1.08	1.08	1.08	1.31
2021–2035	0.01	0.15	0.15	0.26	0.23	0.15	0.26	0.23	0.23	0.03	0.73	0.73	1.33	1.13	0.73	0.73	0.73	0.89
2021–2050	0.01	0.08	0.08	0.14	0.12	0.08	0.14	0.12	0.12	0.04	0.39	0.39	0.71	0.60	0.39	0.39	0.39	0.47

Table 156. Intrastate gas supply DRIPE and gas cross-DRIPE for Massachusetts (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.01	0.73	0.73	1.33	1.14	0.73	1.33	1.17	1.16	0.01	0.72	0.72	1.32	1.13	0.72	0.72	0.72	0.88
2022	0.02	1.09	1.09	1.99	1.69	1.09	1.99	1.74	1.72	0.02	1.10	1.10	2.01	1.71	1.10	1.10	1.10	1.34
2023	0.02	1.19	1.19	2.18	1.86	1.19	2.18	1.91	1.89	0.02	1.33	1.33	2.43	2.07	1.33	1.33	1.33	1.62
2024	0.02	0.93	0.93	1.70	1.44	0.93	1.70	1.49	1.47	0.02	1.10	1.10	2.02	1.72	1.10	1.10	1.10	1.35
2025	0.02	0.77	0.77	1.41	1.20	0.77	1.41	1.24	1.22	0.02	0.90	0.90	1.65	1.40	0.90	0.90	0.90	1.10
2026	0.02	0.51	0.51	0.93	0.80	0.51	0.93	0.82	0.81	0.02	0.64	0.64	1.17	1.00	0.64	0.64	0.64	0.79
2027	0.02	0.32	0.32	0.57	0.49	0.32	0.57	0.50	0.50	0.02	0.41	0.41	0.73	0.63	0.41	0.41	0.41	0.50
2028	0.02	0.23	0.23	0.40	0.34	0.23	0.40	0.35	0.35	0.02	0.29	0.29	0.52	0.44	0.29	0.29	0.29	0.35
2029	0.02	0.14	0.14	0.24	0.21	0.14	0.24	0.21	0.21	0.02	0.18	0.18	0.31	0.27	0.18	0.18	0.18	0.22
2030	0.03	0.06	0.06	0.10	0.09	0.06	0.10	0.09	0.09	0.02	0.09	0.09	0.14	0.12	0.09	0.09	0.09	0.10
2031	0.03	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
2032	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.02	0.61	0.61	1.10	0.94	0.61	1.10	0.97	0.95	0.02	0.68	0.68	1.25	1.06	0.68	0.68	0.68	0.84
2021–2035	0.02	0.41	0.41	0.75	0.64	0.41	0.75	0.66	0.65	0.02	0.47	0.47	0.85	0.72	0.47	0.47	0.47	0.57
2021–2050	0.03	0.22	0.22	0.40	0.34	0.22	0.40	0.35	0.34	0.02	0.25	0.25	0.45	0.38	0.25	0.25	0.25	0.30

Table 157. Intrastate gas supply DRIPE and gas cross-DRIPE for Maine (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.17	0.17	0.32	0.27	0.17	0.32	0.28	0.28	0.02	1.28	1.28	2.34	1.99	1.28	1.28	1.28	1.56
2022	0.00	0.26	0.26	0.49	0.41	0.26	0.49	0.43	0.42	0.03	1.92	1.92	3.52	2.99	1.92	1.92	1.92	2.35
2023	0.00	0.32	0.32	0.59	0.50	0.32	0.59	0.52	0.51	0.04	2.20	2.20	4.02	3.42	2.20	2.20	2.20	2.69
2024	0.00	0.28	0.28	0.51	0.43	0.28	0.51	0.45	0.44	0.04	1.76	1.76	3.21	2.73	1.76	1.76	1.76	2.15
2025	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.04	1.44	1.44	2.62	2.23	1.44	1.44	1.44	1.75
2026	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.28	0.27	0.04	0.99	0.99	1.79	1.53	0.99	0.99	0.99	1.20
2027	0.00	0.11	0.11	0.19	0.16	0.11	0.19	0.17	0.17	0.04	0.62	0.62	1.11	0.95	0.62	0.62	0.62	0.75
2028	0.00	0.08	0.08	0.13	0.11	0.08	0.13	0.12	0.12	0.04	0.44	0.44	0.78	0.67	0.44	0.44	0.44	0.54
2029	0.00	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07	0.04	0.27	0.27	0.47	0.41	0.27	0.27	0.27	0.33
2030	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.13	0.13	0.20	0.18	0.13	0.13	0.13	0.15
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.28	0.27	0.04	1.12	1.12	2.03	1.73	1.12	1.12	1.12	1.36
2021–2035	0.00	0.12	0.12	0.21	0.18	0.12	0.21	0.19	0.19	0.04	0.76	0.76	1.38	1.18	0.76	0.76	0.76	0.93
2021–2050	0.00	0.06	0.06	0.11	0.10	0.06	0.11	0.10	0.10	0.05	0.40	0.40	0.73	0.62	0.40	0.40	0.40	0.49

Table 158. Intrastate gas supply DRIPE and gas cross-DRIPE for New Hampshire (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.16	0.16	0.30	0.25	0.16	0.30	0.26	0.26	0.02	1.29	1.29	2.36	2.01	1.29	1.29	1.29	1.57
2022	0.00	0.25	0.25	0.46	0.39	0.25	0.46	0.40	0.40	0.03	1.94	1.94	3.54	3.02	1.94	1.94	1.94	2.37
2023	0.00	0.30	0.30	0.56	0.47	0.30	0.56	0.49	0.48	0.04	2.22	2.22	4.05	3.45	2.22	2.22	2.22	2.71
2024	0.00	0.27	0.27	0.50	0.42	0.27	0.50	0.44	0.43	0.04	1.76	1.76	3.22	2.74	1.76	1.76	1.76	2.16
2025	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.04	1.43	1.43	2.62	2.23	1.43	1.43	1.43	1.75
2026	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.27	0.27	0.04	0.99	0.99	1.79	1.53	0.99	0.99	0.99	1.20
2027	0.00	0.11	0.11	0.19	0.16	0.11	0.19	0.17	0.17	0.04	0.62	0.62	1.11	0.95	0.62	0.62	0.62	0.75
2028	0.00	0.07	0.07	0.13	0.11	0.07	0.13	0.12	0.12	0.04	0.45	0.45	0.78	0.67	0.45	0.45	0.45	0.54
2029	0.00	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07	0.04	0.28	0.28	0.47	0.41	0.28	0.28	0.28	0.33
2030	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.13	0.13	0.21	0.18	0.13	0.13	0.13	0.15
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.17	0.17	0.30	0.26	0.17	0.30	0.27	0.26	0.04	1.12	1.12	2.04	1.74	1.12	1.12	1.12	1.37
2021–2035	0.00	0.11	0.11	0.21	0.18	0.11	0.21	0.18	0.18	0.04	0.77	0.77	1.39	1.18	0.77	0.77	0.77	0.93
2021–2050	0.00	0.06	0.06	0.11	0.09	0.06	0.11	0.10	0.10	0.05	0.41	0.41	0.74	0.63	0.41	0.41	0.41	0.49

Table 159. Intrastate gas supply DRIPE and gas cross-DRIPE for Rhode Island (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
2021	0.00	0.11	0.11	0.20	0.17	0.11	0.20	0.18	0.17	0.02	1.34	1.34	2.46	2.09	1.34	1.34	1.34	1.64
2022	0.00	0.17	0.17	0.31	0.26	0.17	0.31	0.27	0.27	0.03	2.01	2.01	3.70	3.14	2.01	2.01	2.01	2.47
2023	0.00	0.21	0.21	0.37	0.32	0.21	0.37	0.33	0.32	0.04	2.31	2.31	4.24	3.61	2.31	2.31	2.31	2.83
2024	0.00	0.16	0.16	0.28	0.24	0.16	0.28	0.24	0.24	0.04	1.88	1.88	3.44	2.93	1.88	1.88	1.88	2.30
2025	0.00	0.13	0.13	0.23	0.20	0.13	0.23	0.21	0.20	0.04	1.54	1.54	2.83	2.41	1.54	1.54	1.54	1.89
2026	0.00	0.10	0.10	0.17	0.14	0.10	0.17	0.15	0.15	0.04	1.06	1.06	1.94	1.65	1.06	1.06	1.06	1.30
2027	0.00	0.06	0.06	0.10	0.09	0.06	0.10	0.09	0.09	0.04	0.67	0.67	1.20	1.03	0.67	0.67	0.67	0.81
2028	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06	0.04	0.48	0.48	0.85	0.73	0.48	0.48	0.48	0.58
2029	0.00	0.03	0.03	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.30	0.30	0.51	0.44	0.30	0.30	0.30	0.35
2030	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.04	0.14	0.14	0.22	0.19	0.14	0.14	0.14	0.16
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.10	0.10	0.18	0.16	0.10	0.18	0.16	0.16	0.04	1.19	1.19	2.16	1.84	1.19	1.19	1.19	1.45
2021–2035	0.00	0.07	0.07	0.12	0.11	0.07	0.12	0.11	0.11	0.04	0.81	0.81	1.47	1.25	0.81	0.81	0.81	0.99
2021–2050	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06	0.05	0.43	0.43	0.78	0.67	0.43	0.43	0.43	0.52

Table 160. Intrastate gas supply DRIPE and gas cross-DRIPE for Vermont (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.02	1.42	1.42	2.59	2.21	1.42	1.42	1.42	1.73
2022	0.00	0.05	0.05	0.09	0.08	0.05	0.09	0.08	0.08	0.03	2.14	2.14	3.91	3.33	2.14	2.14	2.14	2.61
2023	0.00	0.06	0.06	0.11	0.09	0.06	0.11	0.09	0.09	0.04	2.46	2.46	4.50	3.83	2.46	2.46	2.46	3.01
2024	0.00	0.05	0.05	0.10	0.08	0.05	0.10	0.08	0.08	0.04	1.98	1.98	3.62	3.09	1.98	1.98	1.98	2.42
2025	0.00	0.04	0.04	0.08	0.07	0.04	0.08	0.07	0.07	0.04	1.63	1.63	2.98	2.54	1.63	1.63	1.63	1.99
2026	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.04	1.13	1.13	2.04	1.74	1.13	1.13	1.13	1.37
2027	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.71	0.71	1.27	1.09	0.71	0.71	0.71	0.86
2028	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.04	0.51	0.51	0.89	0.77	0.51	0.51	0.51	0.61
2029	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.05	0.31	0.31	0.54	0.46	0.31	0.31	0.31	0.37
2030	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.00	0.05	0.15	0.15	0.23	0.20	0.15	0.15	0.15	0.17
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.04	1.26	1.26	2.29	1.95	1.26	1.26	1.26	1.54
2021–2035	0.00	0.02	0.02	0.04	0.03	0.02	0.04	0.03	0.03	0.04	0.86	0.86	1.56	1.33	0.86	0.86	0.86	1.05
2021–2050	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.05	0.45	0.45	0.82	0.70	0.45	0.45	0.45	0.55

Table 161. Avoided natural gas costs by costing period – southern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	*365*	*273*	*151*	*90*	*30*	*10*
2021	$4.45	$5.61	$7.69	$8.67	$16.69	$29.84
2022	$4.24	$5.44	$7.69	$10.19	$19.27	$33.14
2023	$4.03	$5.20	$7.41	$10.03	$18.98	$32.63
2024	$4.35	$5.52	$7.73	$10.35	$19.51	$33.20
2025	$4.41	$5.57	$7.76	$10.42	$19.61	$33.22
2026	$4.52	$5.66	$7.84	$10.54	$19.79	$33.33
2027	$4.58	$5.71	$7.86	$10.61	$19.89	$33.34
2028	$4.72	$5.85	$7.99	$10.76	$20.15	$33.56
2029	$4.85	$5.96	$8.09	$10.91	$20.37	$33.75
2030	$4.91	$6.01	$8.12	$10.97	$20.47	$33.77
2031	$4.92	$6.02	$8.11	$11.00	$20.49	$33.68
2032	$4.99	$6.08	$8.15	$11.08	$20.61	$33.73
2033	$5.06	$6.13	$8.19	$11.15	$20.72	$33.77
2034	$5.08	$6.15	$8.19	$11.18	$20.76	$33.72
2035	$5.09	$6.15	$8.17	$11.20	$20.77	$33.63
2036	$5.14	$6.18	$8.19	$11.25	$20.83	$33.61
2037	$5.18	$6.21	$8.20	$11.30	$20.90	$33.59
2038	$5.22	$6.25	$8.22	$11.35	$20.97	$33.58
2039	$5.27	$6.28	$8.23	$11.40	$21.04	$33.56
2040	$5.31	$6.31	$8.25	$11.45	$21.11	$33.55
2041	$5.36	$6.34	$8.26	$11.50	$21.18	$33.53
2042	$5.40	$6.38	$8.28	$11.55	$21.25	$33.52
2043	$5.45	$6.41	$8.29	$11.60	$21.32	$33.50
2044	$5.50	$6.45	$8.31	$11.66	$21.39	$33.48
2045	$5.54	$6.48	$8.32	$11.71	$21.46	$33.47
2046	$5.59	$6.51	$8.34	$11.76	$21.54	$33.45
2047	$5.64	$6.55	$8.35	$11.81	$21.61	$33.44
2048	$5.69	$6.58	$8.37	$11.87	$21.68	$33.42
2049	$5.73	$6.62	$8.38	$11.92	$21.75	$33.40
2050	$5.78	$6.65	$8.40	$11.97	$21.82	$33.39
2051	$5.83	$6.69	$8.41	$12.03	$21.89	$33.37
2052	$5.88	$6.72	$8.43	$12.08	$21.97	$33.36
2053	$5.93	$6.76	$8.45	$12.13	$22.04	$33.34
2054	$5.98	$6.79	$8.46	$12.19	$22.11	$33.33
2055	$6.03	$6.83	$8.48	$12.24	$22.19	$33.31

Table 162. Avoided natural gas costs by costing period – northern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	*365*	*273*	*151*	*90*	*30*	*10*
2021	$4.28	$5.33	$7.23	$11.55	$19.19	$30.24
2022	$4.07	$5.17	$7.24	$11.65	$21.82	$31.77
2023	$3.86	$4.94	$6.96	$11.30	$21.58	$31.63
2024	$4.18	$5.26	$7.29	$11.60	$22.15	$31.96
2025	$4.25	$5.32	$7.33	$11.60	$22.30	$32.05
2026	$4.36	$5.41	$7.41	$11.63	$22.53	$32.18
2027	$4.42	$5.47	$7.45	$11.63	$22.67	$32.26
2028	$4.56	$5.60	$7.58	$11.71	$22.97	$32.44
2029	$4.69	$5.72	$7.69	$11.78	$23.24	$32.59
2030	$4.75	$5.78	$7.73	$11.78	$23.38	$32.68
2031	$4.77	$5.79	$7.72	$11.73	$23.44	$32.71
2032	$4.84	$5.85	$7.77	$11.74	$23.60	$32.80
2033	$4.91	$5.91	$7.82	$11.75	$23.75	$32.89
2034	$4.94	$5.93	$7.82	$11.71	$23.83	$32.94
2035	$4.95	$5.93	$7.81	$11.66	$23.87	$32.96
2036	$5.00	$5.97	$7.83	$11.64	$23.98	$33.03
2037	$5.04	$6.00	$7.85	$11.63	$24.09	$33.09
2038	$5.09	$6.04	$7.88	$11.61	$24.20	$33.15
2039	$5.14	$6.08	$7.90	$11.59	$24.31	$33.22
2040	$5.18	$6.11	$7.92	$11.57	$24.43	$33.28
2041	$5.23	$6.15	$7.94	$11.55	$24.54	$33.34
2042	$5.28	$6.19	$7.96	$11.54	$24.65	$33.41
2043	$5.33	$6.23	$7.99	$11.52	$24.76	$33.47
2044	$5.38	$6.27	$8.01	$11.50	$24.88	$33.54
2045	$5.43	$6.30	$8.03	$11.48	$24.99	$33.60
2046	$5.48	$6.34	$8.05	$11.46	$25.11	$33.66
2047	$5.53	$6.38	$8.08	$11.45	$25.22	$33.73
2048	$5.58	$6.42	$8.10	$11.43	$25.34	$33.79
2049	$5.63	$6.46	$8.12	$11.41	$25.45	$33.86
2050	$5.68	$6.50	$8.14	$11.39	$25.57	$33.92
2051	$5.73	$6.54	$8.17	$11.37	$25.69	$33.99
2052	$5.79	$6.58	$8.19	$11.36	$25.80	$34.05
2053	$5.84	$6.62	$8.21	$11.34	$25.92	$34.12
2054	$5.89	$6.66	$8.23	$11.32	$26.04	$34.18
2055	$5.95	$6.70	$8.26	$11.30	$26.16	$34.25

APPENDIX D: DETAILED OIL AND OTHER FUELS OUTPUTS

This appendix provides avoided costs for fuel oil and other fuels by year, and by sector. As in the above appendices, annual data is provided alongside levelized costs over three different costing periods: 10-year (2021–2030), 15-year (2021–2035), and 30-year periods (2021–2050). This appendix also details emission values for SO_2, NO_X, CO_2, and CO_2 priced at $100 per ton. Note that these costs and emission values are assumed to be the same for all states and reporting regions in New England.

Table 163 provides the avoided costs for three types of fuel:

- Fuel Oils, which includes distillate fuel oil, residual fuel oil, and a weighted average
- Other Fuels, which includes cord wood, wood pellets, kerosene, and propane
- Transportation fuels, including motor gasoline and motor diesel

Avoided costs for these fuels are shown by year and by applicable sector (residential, commercial, industrial, and/or transportation).

Table 164, Table 165, Table 166, and Table 167 provide information on DRIPE values for specific petroleum products. These tables modify the values shown in Table 104 by multiplying those by the adjustment factors described in Table 105.

All values are also provided in the standalone Excel workbook titled “Appendix D.”

Table 163. Avoided costs of petroleum fuels and other fuels by sector (2021 $ per MMBtu)

Year	Fuel oils							Other Fuels					Transportation	
	Residential	Commercial			Industrial			Residential				Industrial		
	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel Oil	Weighted	Distillate Fuel Oil	Residual Fuel Oil	Weighted	Cord Wood	Wood Pellets	Kero-sene	Pro-pane	Kero-sene	Motor Gasoline	Motor Diesel
2021	$19	$21	$15	$21	$20	$15	$20	$17	$18	$24	$34	$17	$20	$20
2022	$19	$20	$14	$20	$19	$14	$19	$17	$18	$24	$34	$16	$21	$20
2023	$21	$21	$15	$21	$20	$15	$20	$19	$20	$26	$36	$17	$21	$21
2024	$23	$21	$15	$21	$21	$15	$20	$20	$21	$28	$37	$17	$21	$22
2025	$23	$22	$15	$21	$21	$15	$20	$20	$22	$29	$38	$18	$21	$22
2026	$24	$22	$15	$21	$21	$15	$20	$21	$23	$30	$39	$18	$21	$22
2027	$25	$22	$15	$22	$21	$15	$21	$21	$23	$30	$39	$18	$21	$23
2028	$25	$22	$16	$22	$22	$16	$21	$22	$23	$31	$40	$18	$22	$23
2029	$25	$23	$16	$22	$22	$16	$21	$22	$24	$31	$40	$18	$22	$23
2030	$26	$23	$16	$23	$22	$16	$22	$22	$24	$32	$40	$19	$23	$24
2031	$26	$23	$16	$23	$22	$16	$22	$22	$24	$32	$41	$19	$23	$24
2032	$26	$23	$17	$23	$23	$17	$22	$23	$24	$32	$41	$19	$24	$24
2033	$26	$24	$17	$23	$23	$17	$22	$23	$25	$32	$41	$19	$24	$24
2034	$26	$24	$17	$23	$23	$17	$22	$23	$25	$32	$41	$19	$24	$25
2035	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$41	$19	$24	$25
2036	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$41	$20	$25	$25
2037	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$42	$20	$25	$25
2038	$27	$24	$17	$24	$24	$17	$23	$23	$25	$33	$42	$20	$25	$25
2039	$27	$25	$17	$24	$24	$17	$23	$24	$25	$33	$42	$20	$25	$25
2040	$27	$25	$18	$25	$24	$18	$23	$24	$26	$34	$42	$20	$26	$26
2041	$28	$25	$18	$25	$24	$18	$24	$24	$26	$34	$42	$20	$26	$26
2042	$28	$25	$18	$25	$24	$18	$24	$24	$26	$34	$42	$21	$26	$26
2043	$28	$25	$18	$25	$25	$18	$24	$24	$26	$34	$43	$21	$27	$26
2044	$28	$26	$18	$25	$25	$18	$24	$24	$26	$35	$43	$21	$27	$26
2045	$28	$26	$18	$25	$25	$18	$24	$25	$26	$35	$43	$21	$27	$26
2046	$28	$26	$18	$26	$25	$18	$25	$25	$27	$35	$43	$21	$28	$27
2047	$29	$26	$19	$26	$25	$19	$25	$25	$27	$35	$43	$21	$28	$27
2048	$29	$26	$19	$26	$26	$19	$25	$25	$27	$35	$44	$22	$28	$27
2049	$29	$27	$19	$26	$26	$19	$25	$25	$27	$36	$44	$22	$29	$27
2050	$29	$27	$19	$26	$26	$19	$25	$25	$27	$36	$44	$22	$29	$27
2051	$29	$27	$19	$27	$26	$19	$26	$25	$27	$36	$44	$22	$29	$28
2052	$30	$27	$19	$27	$26	$19	$26	$26	$28	$36	$44	$22	$30	$28
2053	$30	$27	$19	$27	$27	$19	$26	$26	$28	$37	$44	$22	$30	$28
2054	$30	$28	$20	$27	$27	$20	$26	$26	$28	$37	$45	$23	$30	$28
2055	$30	$28	$20	$28	$27	$20	$26	$26	$28	$37	$45	$23	$31	$28
2021-2029	$23	$22	$15	$21	$21	$15	$20	$20	$22	$28	$38	$18	$21	$22
2021-2035	$24	$22	$16	$22	$21	$16	$21	$21	$22	$30	$39	$18	$22	$23
2021-2050	$26	$24	$17	$23	$23	$17	$22	$22	$24	$32	$41	$19	$24	$24

Note: Assumes a real discount rate of 0.81 percent.

Table 164. Home heating (diesel) fuel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.09	0.02	0.04	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2022	0.09	0.02	0.04	0.01	0.01	0.01	0.01	0.07	0.05	0.08	0.08	0.09	0.09
2023	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2024	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2025	0.11	0.02	0.05	0.01	0.01	0.01	0.01	0.09	0.06	0.10	0.10	0.10	0.10
2026	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2027	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2028	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2029	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2030	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2031	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2032	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2033	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2034	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2035	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2036	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2037	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.11	0.12	0.12
2038	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2039	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2040	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2041	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2042	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.13
2043	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2044	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2045	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2046	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2047	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2048	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2049	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2050	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2051	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2052	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2053	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2054	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2055	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
Levelized (2021–2035)	0.11	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11

Table 165. Residual fuel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.04	0.04	0.05	0.05
2022	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.05	0.05	0.05	0.05
2023	0.06	0.01	0.02	0.01	0.01	0.00	0.00	0.05	0.03	0.05	0.05	0.06	0.06
2024	0.06	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.05	0.06	0.06	0.06
2025	0.06	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2026	0.07	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2027	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2028	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.07	0.07
2029	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.06	0.07	0.07
2030	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.06	0.07	0.07
2031	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2032	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2033	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2034	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2035	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2036	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2037	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2038	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2039	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2040	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2041	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2042	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2043	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2044	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2045	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2046	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08
2047	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2048	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2049	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2050	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2051	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2052	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2053	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2054	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2055	0.08	0.02	0.04	0.01	0.01	0.00	0.00	0.07	0.05	0.07	0.07	0.08	0.08
Levelized (2021–2035)	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06

Table 166. Motor gasoline DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.08	0.02	0.04	0.01	0.01	0.00	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2022	0.09	0.02	0.04	0.01	0.01	0.01	0.01	0.07	0.05	0.08	0.08	0.09	0.09
2023	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2024	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2025	0.11	0.02	0.05	0.01	0.01	0.01	0.01	0.09	0.06	0.10	0.10	0.10	0.10
2026	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2027	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2028	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2029	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2030	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.11	0.11	0.12	0.12
2031	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2032	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2033	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2034	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2035	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2036	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2037	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2038	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2039	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.11	0.12	0.12
2040	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2041	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2042	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2043	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2044	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2045	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2046	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2047	0.14	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2048	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2049	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2050	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2051	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2052	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2053	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2054	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2055	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
Levelized (2021–2035)	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11

Table 167. Motor diesel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2022	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2023	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2024	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2025	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2026	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2027	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2028	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2029	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2030	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.14
2031	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.13	0.13	0.14	0.14
2032	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2033	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2034	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2035	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2036	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2037	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2038	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2039	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2040	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2041	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2042	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2043	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.15	0.15
2044	0.16	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.15	0.15
2045	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2046	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2047	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2048	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2049	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2050	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2051	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.09	0.14	0.14	0.15	0.15
2052	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.14	0.15	0.15
2053	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.15	0.15
2054	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.16	0.16
2055	0.17	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.16	0.16
Levelized (2021–2035)	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12

APPENDIX E: COMMON FINANCIAL PARAMETERS

This appendix presents values for converting nominal dollars to constant 2021 dollars (2021 $) as well as a real discount rate for calculating illustrative levelized avoided costs. These values are used throughout the AESC 2021 study, including in calculations that convert constant to nominal dollars and in levelization calculations. Note also that the *AESC 2021 User Interface* workbook allows users to specify their own discount rate in the calculation of levelized costs.

In summary, we present a long-term inflation rate similar to those used in past versions of the AESC study, but a lower real discount rate than has previously been used based on the recent rates for U.S. Treasury Bills. Those values are below:

- The value for converting between future nominal dollars and constant 2021 $ is a long-term inflation rate of 2.00 percent (the same used as in AESC 2018).
- The real discount rate is 0.81 percent (versus 1.34 percent in AESC 2018).

Conversion of nominal dollars to constant 2021 dollars

Unless otherwise stated, all dollar values in AESC 2021 are in 2021 dollars. Therefore, a set of inflators is needed to convert prior year nominal dollars into 2021 $, and a set of deflators to convert future year nominal dollars into 2021$. Those values are presented in Table 168. The inflators are calculated from the GDP chain-type price index published by the U.S. Department of Commerce's Bureau of Economic Analysis.[364] The inflation rate during 2020 has varied from a low of 0.1 percent in May and increased to 1.3 percent in August. Based on this upward trend we model an inflation rate of 1.5 percent for 2020.

Table 168. GDP price index and inflation rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2021$
2000	78.08		1.489
2001	79.79	2.19%	1.457
2002	81.05	1.58%	1.434
2003	82.56	1.86%	1.408
2004	84.78	2.69%	1.371
2005	87.42	3.12%	1.330
2006	90.07	3.03%	1.290
2007	92.49	2.69%	1.257
2008	94.29	1.95%	1.233
2009	95.00	0.76%	1.223

[364] U.S. Department of Commerce, Bureau of Economic Analysis, Table 1.1.9 Implicit Price Deflators for Gross Domestic Product, 8/20/20.

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2021$
2010	96.11	1.17%	1.209
2011	98.12	2.09%	1.185
2012	100.00	1.92%	1.162
2013	101.76	1.76%	1.142
2014	103.64	1.85%	1.121
2015	104.62	0.95%	1.111
2016	105.72	1.05%	1.099
2017	107.71	1.88%	1.079
2018	110.30	2.40%	1.054
2019	112.27	1.79%	1.035
2020	113.95	1.50%	1.020
2021	**116.23**	**2.00%**	**1.000**
2022	118.55	2.00%	0.980
2023	120.92	2.00%	0.961
2024	123.34	2.00%	0.942
2025	125.81	2.00%	0.924
2026	128.33	2.00%	0.906
2027	130.89	2.00%	0.888
2028	133.51	2.00%	0.871
2029	136.18	2.00%	0.853
2030	138.90	2.00%	0.837
2031	141.68	2.00%	0.820
2032	144.51	2.00%	0.804
2033	147.41	2.00%	0.788
2034	150.35	2.00%	0.773
2035	153.36	2.00%	0.758
2036	156.43	2.00%	0.743
2037	159.56	2.00%	0.728
2038	162.75	2.00%	0.714
2039	166.00	2.00%	0.700
2040	169.32	2.00%	0.686
2041	172.71	2.00%	0.673
2042	176.16	2.00%	0.660
2043	179.69	2.00%	0.647
2044	183.28	2.00%	0.634
2045	186.95	2.00%	0.622
2046	190.68	2.00%	0.610
2047	194.50	2.00%	0.598
2048	198.39	2.00%	0.586
2049	202.36	2.00%	0.574
2050	206.40	2.00%	0.563

For the years in our analysis, we use a long-term inflation rate of 2.00 percent. This is the same inflation rate used in the AESC 2018 study. The 2 percent inflation rate is also consistent with the 20-year annual average inflation rate from 2001 to 2019 of 1.93 percent, derived from the GDP chain-type price index. We also examined projections of long-term inflation made by the Congressional Budget Office (CBO) in January 2020 which were 2.00 percent for 2025–2030.[365] In both August and September, the Federal Reserve Board indicated its intent of maintaining a long-term average inflation rate of 2.0 percent. The rate may however vary over the shorter term to address employment problems.[366] Note also that the long-term rate used in the 2020 AEO was 2.30 percent.[367]

Real discount rate

The calculation of the real discount rate uses the inflation rate, as discussed above, in conjunction with the long-term nominal discount rate. To develop a real discount rate, we used the calculated nominal rate and the forecast long-term inflation rate (2.00 percent) according to the formula in Equation 17.

Equation 17. Calculating the real discount rate

$$Real\ discount\ rate = \frac{1 + nominal\ discount\ rate}{1 + inflation\ rate} - 1$$

For the nominal discount rate, past AESC studies have generally used 30-year Treasury bills. Because of unusual market conditions (where short-term rates were higher than long-term rates) in AESC 2018 we used a blending of the 10-year and 30-year rates. For this study we return to the use of the 30-year T-Bills. Rates on Treasury bills have declined dramatically in recent years, and have continued to do so to a greater degree during the COVID-19 pandemic (see Figure 62). Through most of 2018, treasury bill rates were about 3 percent, and then declined to about 2.5 percent in 2019. As of July 2020, because of the effects of the COVID-19 pandemic, the 30-year bills were at 1.25 percent and 10-year bills were at 0.62 percent.[368]

Since AESC 2021 requires a long-term value, we use the average of the 30-year T-Bill rates for the two years prior to the COVID-19 pandemic,[369] which is 2.82 percent. This is not greatly different than the

[365] CBO, The Budget and Economic Outlook: Fiscal Years 2020 to 2030, Table 2-1, page 30, January 2020. The same 2025-2030 GDP price index value of 2.0 percent was in the July 2020 update.

[366] Federal Reserve. August 27, 2020. "Federal Open Market Committee Announces Approval of Updates to its Statement on Longer-Run Goals and Monetary Policy Strategy." *Federalreserve.gov.* Available at https://www.federalreserve.gov/newsevents/pressreleases/monetary20200827a.htm.

[367] U.S. EIA. Last accessed March 10, 2021. "Annual Energy Outlook 2020." *Eia.gov.* Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2020&cases=ref2020&sourcekey=0.

[368] As of January 2021, 30-year bills were at 1.87 percent and 10-year bills were at 1.12 percent. These are not substantially different enough to warrant altering the results presented here.

[369] From January 2018 through January 2020.

rate of 3.37 percent used In AESC 2018. This results in a nominal discount rate of 2.82 percent. The resultant future nominal price indices are shown in shown in Table 169.

Figure 62. Recent treasury bill rates at the time of AESC 2021's input assumption development

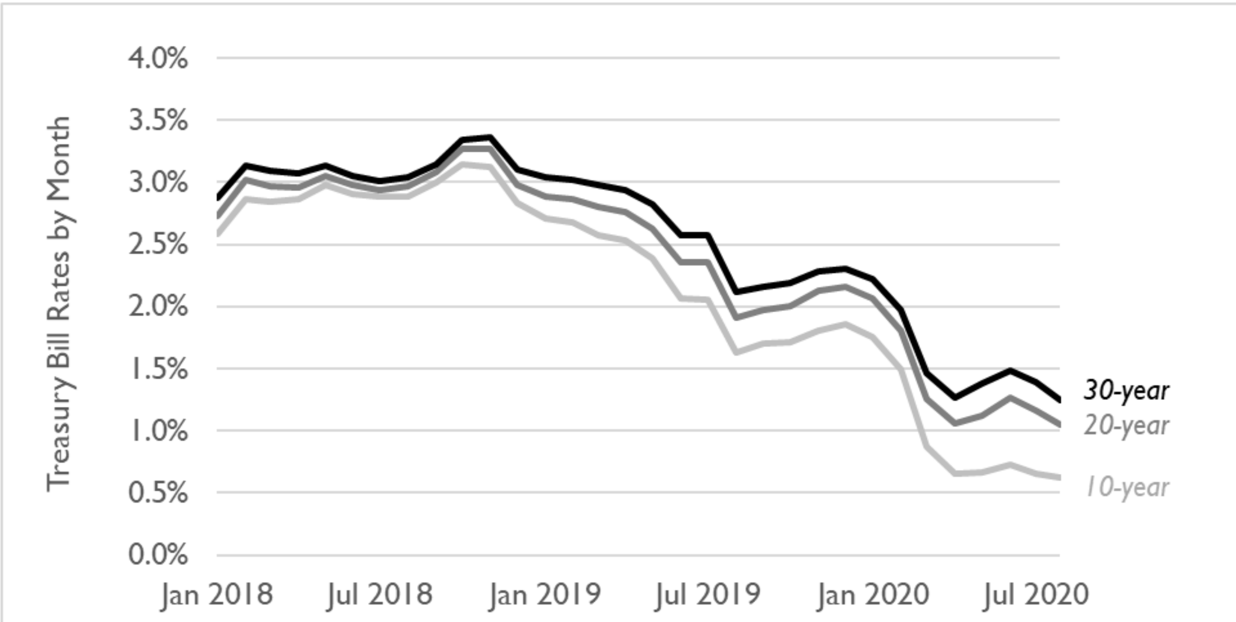


Table 169. Composite nominal rate calculation

Year	Rate	Index	Year	Rate	Index
2021	2.82%	1.000	2039	2.82%	1.650
2022	2.82%	1.028	2040	2.82%	1.697
2023	2.82%	1.057	2041	2.82%	1.745
2024	2.82%	1.087	2042	2.82%	1.794
2025	2.82%	1.118	2043	2.82%	1.845
2026	2.82%	1.149	2044	2.82%	1.897
2027	2.82%	1.182	2045	2.82%	1.950
2028	2.82%	1.215	2046	2.82%	2.005
2029	2.82%	1.249	2047	2.82%	2.062
2030	2.82%	1.285	2048	2.82%	2.120
2031	2.82%	1.321	2049	2.82%	2.180
2032	2.82%	1.358	2050	2.82%	2.242
2033	2.82%	1.397			
2034	2.82%	1.436			
2035	2.82%	1.476			
2036	2.82%	1.518			
2037	2.82%	1.561			
2038	2.82%	1.605			

Notes: A nominal rate of 2.82 percent used throughout the period.

AESC 2021 requires the calculation of illustrative levelized avoided costs expressed in 2021$ for various intervals using the identified real discount rate. Note that the *AESC 2021 User Interface* workbook allows readers of AESC 2021 to input their preferred discount rate to calculate levelized avoided costs.

The real discount rate formula produces a rate of 0.81 percent, which appears reasonable for calculations of levelized costs through periods as long as 30 years.[370] This is lower than the AESC 2018 rate of 1.34 percent and significantly lower than the AESC 2015 rate of 2.43 percent. But as discussed above, the longer-term nominal return rates have declined considerably. We thus rely on a real discount rate of 0.81 percent. A lower discount rate means that future costs and savings will have greater effects on the net present value calculations. Table 170 presents a summary of our findings.

Table 170. Comparison of real discount rate estimates

	AESC 2018	Treasury Bill Method *8/20/2020*	Congressional Budget Office *Jan-20*	Congressional Budget Office *Jul-20*	AESC 2021
Long-term nominal rate	3.37%	1.05%	3.00%	2.60%	**2.82%**
Source	Composite of 10 and 30-year Treasury rates	30-year T-Bills with maturities 2030–2049	Forecast: 10-year Treasury notes 2025–2030	Forecast: 10-year Treasury notes 2025–2030	**30 Year T-Bills Jan 2018–Jan 2020**
Inflation Rate	2.00%	2.00%	2.00%	2.00%	**2.00%**
Source	Above historical average of 1.88%, but below AEO 2017 projection of 2.1%; same as CBO forecast	Slightly above historical average, but greater than the long-term rate	Core PCE Price Index 2025–2030	Core PCE Price Index 2025–2030	**Above historical average of 1.88%, but below AEO 2020 projection of 2.3%; same as CBO forecast**
Resulting long-term real discount rate	1.34%	-0.93%	0.98%	0.59%	**0.81%**

Sources: January 2020 CBO rate is taken from "The Budget and Economic Outlook: Fiscal Years 2020 to 2030," Congressional Budget Office, January 2020, Table 2-1. July 2020. CBO rate is taken from An Update to The Budget and Economic Outlook: Fiscal Years 2020 to 2030*, Congressional Budget Office, July 2020, Table 1.*

[370] This is the standard rate conversion equation used widely and in all previous AESC studies.

Considerations given the COVID-19 pandemic

The effects of the COVID-19 pandemic have greatly affected the U.S. economy. The most significant changes have been declines in employment and economic activity. The effects also show up in the near collapse of interest rates as reflected in the T-Bills. The inflation rate has been affected very little.

APPENDIX F: USER INTERFACE

The *Avoided Cost User Interface* is an Excel-based document that allows readers of AESC 2021 to examine hour-by-hour energy prices and DRIPE values for each reporting region for 2021 through 2035. This document serves as a data aggregator; it pulls together energy and DRIPE data for the traditional AESC costing periods and discount rates, allowing users to view—and modify—levelized avoided costs. This document also provides an extrapolation of energy prices and DRIPE values through 2055, using the extrapolation methodology described in Appendix A: *Usage Instructions*.

However, the main purpose of this document is to allow users to develop avoided costs for periods outside the traditional AESC costing periods of summer off-peak, summer on-peak, winter off-peak, and winter on-peak. Within the *AESC 2021 User Interface*, users can develop customized costs using the following selectable options:

- **Time period:** The interface provides energy and DRIPE values modeled from 2021 through 2035 and extrapolated through 2055.
- **Levelization period:** Users can view costs levelized using the standard levelization periods (10-year, 15-year, and 30-year) or develop their own levelization periods over other years.
- **AESC reporting zone:** Users may choose one of 11 reporting regions for which to calculate avoided costs (including reporting regions not included in Appendix B).
- **Costing period:** Users can view the costs under the traditional four costing periods, or define their own, as follows:
    - Peak load (defined as “X” percent of hours exceeding “Y” percentile of load)
    - Load threshold (defined as “X” hours exceeding “Y MW”)
    - Peak price (defined as “X” percent of hours exceeding “Y” percentile of price)
    - Price threshold (defined as “X” hours exceeding “$Y/MWh”)
- **Counterfactuals:** Users may create avoided costs for each of the four AESC counterfactuals.

APPENDIX G: MARGINAL EMISSION RATES AND NON-EMBEDDED ENVIRONMENTAL COST DETAIL

This appendix presents the modeled emission rates for CO_2 and NO_X in the non-electric sectors (Table 171) and in the electric sector (Table 172). We also present the "RE Factor" in Table 173, which is calculated based on the modeling results and the algorithm described in Section 8.3: *Applying non-embedded costs*. This RE Factor may be applied to the marginal emission rates in Table 172 to determine final marginal emission rates for each state.

Users of AESC 2021 must make a determination for which non-embedded costs are most applicable to their own policy context. For illustrative purposes, Table 174 through Table 176 depict the electric and non-electric non-embedded costs assuming the New England marginal abatement cost derived from electric sector technologies (see Section 8.1: *Non-embedded GHG costs*), under Counterfactual #1 for Massachusetts (as an example state). Users of AESC 2021 may utilize the *AESC 2021 User Interface* to generate analogous tables for each of the non-embedded costs described in Section 8.1: *Non-embedded GHG costs*, for each counterfactual, for each state. These tables account for the removal of embedded costs (RGGI for all states, plus costs associated with 310 CMR 7.74 and 7.75 for Massachusetts).

Note that the avoided costs described in Table 174 through Table 176 are already included in Appendix B. These should not be added, and they are shown here for informational purposes only.

Table 171. Marginal emission rates for non-electric sectors

Fuel	Sector	CO_2	NO_X
Natural Gas	Residential	117	0.092
	Commercial	117	0.098
	Industrial	117	0.098
Distillate fuel oil	Residential	161	0.129
	Commercial	161	0.171
	Industrial	161	0.171
B5 Biofuel	All	153	0.129
B20 Biofuel	All	129	0.129
Kerosene	All	159	0.129
LPG	All	139	0.014
RFO	All	173	0.171
Transportation Diesel	All	161	0.717
Gasoline	All	157	0.124
Wood	All	zero	0.341
Wood & Waste	All	zero	0.355

Sources: CO_2 emissions rates from https://www.eia.gov/environment/emissions/co2_vol_mass.php; NOX emissions rates from EPA, AP 42, Fifth Edition, Volume I. Chapter 1: External Combustion Sources, available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html; Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the US Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. See Tables 1-35, 4-43, and 4-6M.
Notes: Some emissions rates do not vary by sector or geography and are consistent across years. NO_X emission rates for transportation diesel and gasoline are shown for national averages of all vehicles on the road.

Table 172. Modeled short-term electric sector marginal emissions rates (lb per MWh)

	CO_2				NO_X			
	Winter		Summer		Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*
2021	756	791	779	799	0.09	0.21	0.14	0.11
2022	740	752	729	813	0.10	0.09	0.14	0.11
2023	732	826	663	932	0.09	0.08	0.11	0.09
2024	791	869	767	967	0.10	0.08	0.12	0.10
2025	796	881	812	966	0.07	0.07	0.12	0.10
2026	756	878	772	939	0.07	0.07	0.11	0.09
2027	682	824	760	930	0.07	0.08	0.11	0.10
2028	686	735	764	822	0.08	0.07	0.12	0.09
2029	702	718	753	794	0.08	0.07	0.11	0.08
2030	636	669	732	760	0.06	0.06	0.09	0.07
2031	648	692	723	768	0.06	0.06	0.09	0.07
2032	644	720	686	774	0.06	0.06	0.09	0.07
2033	652	702	737	788	0.06	0.06	0.08	0.07
2034	678	693	752	770	0.06	0.06	0.08	0.07
2035	691	690	761	793	0.06	0.05	0.07	0.06

We assume all four counterfactuals feature the same marginal emission rates.

Table 173. RE Factor

	CT	MA	ME	NH	RI	VT
2021	0%	0%	0%	1%	0%	8%
2022	0%	0%	0%	1%	0%	9%
2023	0%	0%	0%	1%	0%	11%
2024	0%	0%	0%	1%	0%	12%
2025	0%	0%	0%	1%	0%	13%
2026	0%	0%	0%	1%	0%	14%
2027	0%	0%	0%	1%	0%	16%
2028	0%	0%	0%	1%	0%	17%
2029	0%	0%	0%	1%	0%	18%
2030	0%	0%	0%	1%	0%	19%
2031	0%	0%	0%	1%	0%	21%
2032	0%	0%	0%	1%	0%	22%
2033	0%	0%	0%	1%	0%	22%
2034	0%	0%	0%	1%	0%	22%
2035	0%	0%	0%	1%	0%	22%

Notes: See development methodology in Section 8.3: Applying non-embedded costs*. The RE Factor does not change for different scenarios—see discussion in Chapter 7.* Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies *as to why.*

Table 174. Electric sector non-embedded costs in Counterfactual #1, WCMA (2021 $ per kWh)

	CO_2				NO_X			
	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*
2021	0.0695	0.0728	0.0717	0.0735	0.0007	0.0015	0.0010	0.0008
2022	0.0575	0.0584	0.0567	0.0632	0.0008	0.0006	0.0010	0.0008
2023	0.0582	0.0657	0.0527	0.0741	0.0006	0.0006	0.0008	0.0007
2024	0.0480	0.0527	0.0465	0.0587	0.0007	0.0006	0.0009	0.0007
2025	0.0484	0.0536	0.0494	0.0587	0.0005	0.0005	0.0009	0.0007
2026	0.0444	0.0515	0.0453	0.0551	0.0005	0.0005	0.0008	0.0007
2027	0.0400	0.0483	0.0446	0.0545	0.0005	0.0006	0.0008	0.0007
2028	0.0403	0.0431	0.0449	0.0483	0.0006	0.0005	0.0009	0.0007
2029	0.0384	0.0393	0.0412	0.0434	0.0006	0.0005	0.0008	0.0006
2030	0.0355	0.0374	0.0409	0.0424	0.0004	0.0004	0.0006	0.0005
2031	0.0325	0.0347	0.0362	0.0385	0.0005	0.0004	0.0006	0.0005
2032	0.0293	0.0328	0.0312	0.0353	0.0005	0.0005	0.0006	0.0005
2033	0.0272	0.0293	0.0308	0.0329	0.0004	0.0004	0.0006	0.0005
2034	0.0257	0.0263	0.0285	0.0292	0.0005	0.0004	0.0006	0.0005
2035	0.0235	0.0235	0.0259	0.0270	0.0004	0.0004	0.0005	0.0005
2036	0.0216	0.0214	0.0237	0.0246	0.0004	0.0004	0.0005	0.0005
2037	0.0199	0.0195	0.0217	0.0224	0.0004	0.0004	0.0005	0.0005
2038	0.0183	0.0177	0.0198	0.0205	0.0004	0.0004	0.0005	0.0004
2039	0.0169	0.0162	0.0181	0.0187	0.0004	0.0004	0.0005	0.0004
2040	0.0155	0.0147	0.0166	0.0171	0.0004	0.0004	0.0005	0.0004
2041	0.0143	0.0134	0.0152	0.0156	0.0004	0.0004	0.0005	0.0004
2042	0.0132	0.0122	0.0139	0.0142	0.0004	0.0004	0.0005	0.0004
2043	0.0121	0.0111	0.0127	0.0130	0.0004	0.0004	0.0004	0.0004
2044	0.0112	0.0101	0.0116	0.0118	0.0004	0.0004	0.0004	0.0004
2045	0.0103	0.0092	0.0106	0.0108	0.0004	0.0003	0.0004	0.0004
2046	0.0095	0.0084	0.0097	0.0099	0.0004	0.0003	0.0004	0.0004
2047	0.0087	0.0077	0.0089	0.0090	0.0004	0.0003	0.0004	0.0004
2048	0.0080	0.0070	0.0081	0.0082	0.0004	0.0003	0.0004	0.0004
2049	0.0074	0.0064	0.0075	0.0075	0.0004	0.0003	0.0004	0.0003
2050	0.0068	0.0058	0.0068	0.0068	0.0004	0.0003	0.0004	0.0003
2051	0.0063	0.0053	0.0062	0.0062	0.0004	0.0003	0.0004	0.0003
2052	0.0058	0.0048	0.0057	0.0057	0.0004	0.0003	0.0004	0.0003
2053	0.0053	0.0044	0.0052	0.0052	0.0004	0.0003	0.0003	0.0003
2054	0.0049	0.0040	0.0048	0.0047	0.0004	0.0003	0.0003	0.0003
2055	0.0045	0.0036	0.0044	0.0043	0.0004	0.0003	0.0003	0.0003
Levelized (2021-2030)	0.0482	0.0525	0.0496	0.0574	0.0006	0.0006	0.0009	0.0007
Levelized (2021-2035)	0.0417	0.0451	0.0435	0.0495	0.0005	0.0006	0.0008	0.0006
Levelized (2021-2050)	0.0282	0.0297	0.0295	0.0329	0.0005	0.0005	0.0006	0.0005

Notes: Values are for Counterfactual #1 only. CO_2 price assumes New England marginal abatement cost derived from electric sector technologies. Prices in Massachusetts diverge from other states due to the presence of unique Massachusetts-specific GHG regulations. Other CO_2 prices can be calculated using the AESC 2021 User Interface*. Values shown do not have losses applied.*

Table 175. Non-electric non-embedded costs for CO_2 in Counterfactual #1, all states (2021 $ per MMBtu)

	Natural Gas			Fuel oils							Other Fuels						
				Resi.	Commercial			Industrial			Residential				Industrial	Transportation	
	Residential	Commer-cial	Indus-trial	*Distillate Fuel Oil*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Cord Wood*	*Pellets*	*Kerosene*	*Propane*	*Kerosene*	*Motor Gasoline*	*Motor Diesel*
2021	$11.15	$11.15	$11.15	$15.34	$15.34	$16.49	$15.39	$15.34	$16.49	$15.44	$0.00	$0.00	$15.15	$13.25	$15.15	$14.96	$15.34
2022	$9.47	$9.47	$9.47	$13.03	$13.03	$14.00	$13.06	$13.03	$14.00	$13.11	$0.00	$0.00	$12.86	$11.25	$12.86	$12.70	$13.03
2023	$9.69	$9.69	$9.69	$13.33	$13.33	$14.33	$13.37	$13.33	$14.33	$13.42	$0.00	$0.00	$13.17	$11.51	$13.17	$13.00	$13.33
2024	$7.51	$7.51	$7.51	$10.33	$10.33	$11.10	$10.36	$10.33	$11.10	$10.39	$0.00	$0.00	$10.20	$8.92	$10.20	$10.07	$10.33
2025	$7.54	$7.54	$7.54	$10.37	$10.37	$11.14	$10.40	$10.37	$11.14	$10.44	$0.00	$0.00	$10.24	$8.95	$10.24	$10.11	$10.37
2026	$7.31	$7.31	$7.31	$10.06	$10.06	$10.81	$10.09	$10.06	$10.81	$10.13	$0.00	$0.00	$9.94	$8.69	$9.94	$9.81	$10.06
2027	$7.33	$7.33	$7.33	$10.09	$10.09	$10.84	$10.12	$10.09	$10.84	$10.15	$0.00	$0.00	$9.96	$8.71	$9.96	$9.83	$10.09
2028	$7.36	$7.36	$7.36	$10.13	$10.13	$10.89	$10.16	$10.13	$10.89	$10.20	$0.00	$0.00	$10.01	$8.75	$10.01	$9.88	$10.13
2029	$6.92	$6.92	$6.92	$9.52	$9.52	$10.23	$9.55	$9.52	$10.23	$9.58	$0.00	$0.00	$9.40	$8.22	$9.40	$9.28	$9.52
2030	$7.07	$7.07	$7.07	$9.73	$9.73	$10.46	$9.76	$9.73	$10.46	$9.79	$0.00	$0.00	$9.61	$8.40	$9.61	$9.49	$9.73
2031	$6.43	$6.43	$6.43	$8.84	$8.84	$9.50	$8.87	$8.84	$9.50	$8.90	$0.00	$0.00	$8.73	$7.63	$8.73	$8.62	$8.84
2032	$5.92	$5.92	$5.92	$8.15	$8.15	$8.75	$8.17	$8.15	$8.75	$8.20	$0.00	$0.00	$8.05	$7.03	$8.05	$7.95	$8.15
2033	$5.50	$5.50	$5.50	$7.57	$7.57	$8.14	$7.59	$7.57	$8.14	$7.62	$0.00	$0.00	$7.48	$6.54	$7.48	$7.38	$7.57
2034	$5.09	$5.09	$5.09	$7.00	$7.00	$7.52	$7.02	$7.00	$7.52	$7.05	$0.00	$0.00	$6.91	$6.05	$6.91	$6.83	$7.00
2035	$4.66	$4.66	$4.66	$6.42	$6.42	$6.89	$6.44	$6.42	$6.89	$6.46	$0.00	$0.00	$6.34	$5.54	$6.34	$6.26	$6.42
2036	$4.29	$4.29	$4.29	$5.91	$5.91	$6.35	$5.93	$5.91	$6.35	$5.94	$0.00	$0.00	$5.83	$5.10	$5.83	$5.76	$5.91
2037	$3.95	$3.95	$3.95	$5.44	$5.44	$5.84	$5.46	$5.44	$5.84	$5.47	$0.00	$0.00	$5.37	$4.70	$5.37	$5.30	$5.44
2038	$3.64	$3.64	$3.64	$5.01	$5.01	$5.38	$5.02	$5.01	$5.38	$5.04	$0.00	$0.00	$4.95	$4.32	$4.95	$4.88	$5.01
2039	$3.35	$3.35	$3.35	$4.61	$4.61	$4.95	$4.62	$4.61	$4.95	$4.64	$0.00	$0.00	$4.55	$3.98	$4.55	$4.50	$4.61
2040	$3.08	$3.08	$3.08	$4.24	$4.24	$4.56	$4.26	$4.24	$4.56	$4.27	$0.00	$0.00	$4.19	$3.66	$4.19	$4.14	$4.24
2041	$2.84	$2.84	$2.84	$3.91	$3.91	$4.20	$3.92	$3.91	$4.20	$3.93	$0.00	$0.00	$3.86	$3.37	$3.86	$3.81	$3.91
2042	$2.61	$2.61	$2.61	$3.60	$3.60	$3.87	$3.61	$3.60	$3.87	$3.62	$0.00	$0.00	$3.55	$3.11	$3.55	$3.51	$3.60
2043	$2.41	$2.41	$2.41	$3.31	$3.31	$3.56	$3.32	$3.31	$3.56	$3.33	$0.00	$0.00	$3.27	$2.86	$3.27	$3.23	$3.31
2044	$2.22	$2.22	$2.22	$3.05	$3.05	$3.28	$3.06	$3.05	$3.28	$3.07	$0.00	$0.00	$3.01	$2.63	$3.01	$2.97	$3.05
2045	$2.04	$2.04	$2.04	$2.81	$2.81	$3.02	$2.82	$2.81	$3.02	$2.83	$0.00	$0.00	$2.77	$2.42	$2.77	$2.74	$2.81
2046	$1.88	$1.88	$1.88	$2.59	$2.59	$2.78	$2.59	$2.59	$2.78	$2.60	$0.00	$0.00	$2.55	$2.23	$2.55	$2.52	$2.59
2047	$1.73	$1.73	$1.73	$2.38	$2.38	$2.56	$2.39	$2.38	$2.56	$2.39	$0.00	$0.00	$2.35	$2.05	$2.35	$2.32	$2.38
2048	$1.59	$1.59	$1.59	$2.19	$2.19	$2.35	$2.20	$2.19	$2.35	$2.20	$0.00	$0.00	$2.16	$1.89	$2.16	$2.14	$2.19
2049	$1.47	$1.47	$1.47	$2.02	$2.02	$2.17	$2.02	$2.02	$2.17	$2.03	$0.00	$0.00	$1.99	$1.74	$1.99	$1.97	$2.02
2050	$1.35	$1.35	$1.35	$1.86	$1.86	$2.00	$1.86	$1.86	$2.00	$1.87	$0.00	$0.00	$1.83	$1.60	$1.83	$1.81	$1.86
2051	$1.24	$1.24	$1.24	$1.71	$1.71	$1.84	$1.72	$1.71	$1.84	$1.72	$0.00	$0.00	$1.69	$1.48	$1.69	$1.67	$1.71
2052	$1.14	$1.14	$1.14	$1.57	$1.57	$1.69	$1.58	$1.57	$1.69	$1.58	$0.00	$0.00	$1.55	$1.36	$1.55	$1.54	$1.57
2053	$1.05	$1.05	$1.05	$1.45	$1.45	$1.56	$1.45	$1.45	$1.56	$1.46	$0.00	$0.00	$1.43	$1.25	$1.43	$1.41	$1.45
2054	$0.97	$0.97	$0.97	$1.33	$1.33	$1.43	$1.34	$1.33	$1.43	$1.34	$0.00	$0.00	$1.32	$1.15	$1.32	$1.30	$1.33
2055	$0.89	$0.89	$0.89	$1.23	$1.23	$1.32	$1.23	$1.23	$1.32	$1.24	$0.00	$0.00	$1.21	$1.06	$1.21	$1.20	$1.23
Levelized																	
2021-2030	$8.16	$8.16	$8.16	$11.23	$11.23	$12.07	$11.26	$11.23	$12.07	$11.30	$0.00	$0.00	$11.09	$9.70	$11.09	$10.95	$11.23
2021-2035	$7.32	$7.32	$7.32	$10.07	$10.07	$10.82	$10.10	$10.07	$10.82	$10.13	$0.00	$0.00	$9.95	$8.69	$9.95	$9.82	$10.07
2021-2050	$5.10	$5.10	$5.10	$7.02	$7.02	$7.54	$7.04	$7.02	$7.54	$7.06	$0.00	$0.00	$6.93	$6.06	$6.93	$6.84	$7.02

Notes: CO_2 price assumes New England marginal abatement cost derived from electric sector technologies. Other CO_2 prices can be calculated using the AESC 2021 User Interface.

Table 176. Non-electric non-embedded costs for NO_X in Counterfactual #1, all states (2021 $ per MMBtu)

	Natural Gas			Fuel oils							Other Fuels						
				Resi.	Commercial			Industrial			Residential				Industrial	Transportation	
	Residential	Commer-cial	Indus-trial	*Distillate Fuel Oil*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Cord Wood*	*Pellets*	*Kerosene*	*Propane*	*Kerosene*	*Motor Gasoline*	*Motor Diesel*
2021	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2022	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2023	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2024	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2025	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2026	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2027	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2028	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2029	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2030	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2031	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2032	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2033	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2034	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2035	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2036	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2037	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2038	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2039	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2040	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2041	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2042	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2043	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2044	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2045	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2046	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2047	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2048	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2049	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2050	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2051	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2052	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2053	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2054	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2055	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
Levelized																	
2021-2030	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2021-2035	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2021-2050	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27

APPENDIX H: DRIPE DERIVATION

This appendix describes the derivation of demand reduction induced price effects (DRIPE). This is the price effect of adding energy efficiency resources or reducing load.

For the supply curve (the price that suppliers will charge for supplying *x* MW):

$$S_0 = b_S + m_s x,$$

and the demand curve (the price set by the VRR curve for *x* MW):

$$D_0 = b_D - m_D x$$

Note that m_D is the magnitude of the slope with the direction noted in the preceding negative sign.

The demand curve meets the supply curve at

$$x \quad = \frac{b_D - b_s}{m_s + m_D}$$

And the market-clearing price is

$$Price \quad = b_D - m_D \left(\frac{b_D - b_s}{m_s + m_D} \right)$$

A positive horizontal shift of α MW to the supply curve shifts the supply y-intercept downward. A negative horizontal shift of the demand curve shifts the demand y-intercept downward as well.

The horizontal shift of the supply curve shifts its y-intercept:

$$b_{supply\ shifted} = b_S - m_S \alpha$$

The Supply function, horizontally shifted + α units, equals:

$$S_{shifted} = m_s x + (b_S - m_s \alpha) = m_s(x - \alpha) + b_S$$

Similarly, applying a negative horizontal shift of α units to the demand curve shifts its y-intercept:

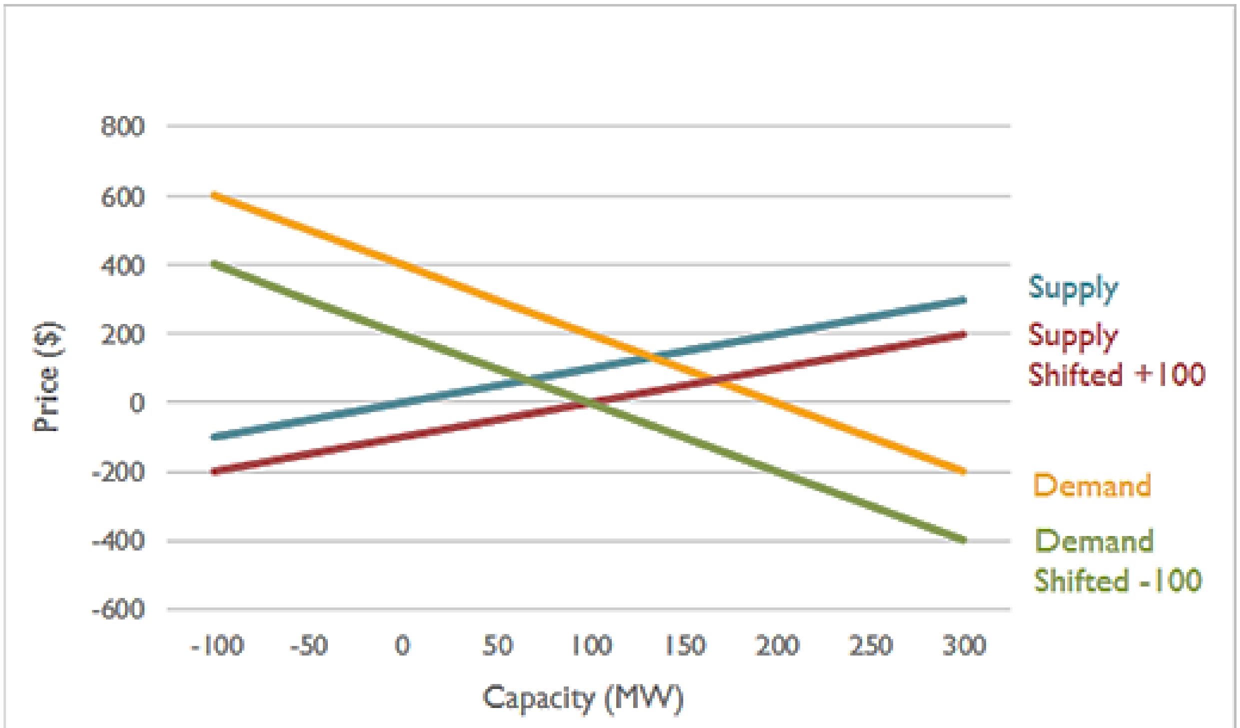
$$b_{demand\ shifted} = b_D - m_D \alpha$$

The shifted Demand function equals:

$$D_{shifted} = b_D - m_D(\alpha + x)$$

Figure 63 provides examples that describe the rationale for the shift in the y-intercept for each function. The supply function is S = x + 0 and the demand function is D = 400–2x. Adding 100 MW at $0 shifts the supply curve right by $100 \times m_S = 100$. Subtracting 100 MW from the demand curve likewise shifts that curve left by 100, equivalent to shifting down by $100 \times m_p = 200$.

Figure 63. Example of supply and demand impact



For the intersection of the supply curve S_0 with the VRR $D_{shifted}$ and the intersection of $S_{shifted}$ with D_0, we find the equilibrium quantity x^* and then substitute that into either half to get $Price^*$.

For $S_0 = D_{shifted}$

$$m_s x + b_S = b_D - m_D(\alpha + x)$$

Solve for x

$$x^* = \frac{b_D - b_s + m_s\alpha}{m_s + m_D}$$

$$Substitute\ x^*\ into\ S_0\ or\ D_{shifted}\ to\ get\ Price$$

$$Price^* = b_D - m_D\left(\frac{b_D - b_s + m_s\alpha}{m_s + m_D}\right)$$

The difference between this price and the original price is

$$\Delta Price \quad = m_D\left(\frac{m_s\alpha}{m_s + m_D}\right)$$

Thus, the slope of the clearing price with respect to demand is

$$\left(\frac{m_D \times m_s}{m_s + m_D}\right)$$

The same approach gives the same result, starting with an increment in supply.

APPENDIX I: MATRIX OF RELIABILITY SOURCES

This appendix documents the studies in Chapter 11: *Value of Improved Reliability*.

Table 177. Matrix of reliability sources

Year	Author	Title	Journal or Source	Document Focus
2018	Cambridge Economic Policy Associates Ltd.	*Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe*	Prepare for Agency for the Cooperation of Energy Regulators. Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf	Reliability Value Assessment – VoLL Methods
2017	Makovich, L., Richards, J.	*Ensuring Resilient and Efficiency Electricity Generation: the Value of the Current Diverse US power supply portfolio*	IHS Market, research supported by the Edison Electric Institute available at: https://www.globalenergyinstitute.org/sites/default/files/Value%20of%20the%20Current%20Diverse%20US%20Power%20Supply%20Portfolio_V3-WB.PDF	Reliability Value Assessment – Macroeconomic Metrics
2017	Mills, E., Jones, R.	*An Insurance Perspective on U.S. Electric Grid Disruption Costs*	LBNL-1006392, performed by the Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory. Available at https://emp.lbl.gov/sites/default/files/lbnl-1006392.pdf	Reliability Value Assessment – VoLL by Sector per Event
2017	North American Electric Reliability Corporation	*Distributed Energy Resources: Connection Modeling and Reliability Considerations*	A report by NERC and the NERC Essential Reliability Services Working Group (ERSWG) Available at http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DERTF%20Draft%20Report%20-%20Connection%20Modeling%20and%20Reliability%20Considerations.pdf	Alternative Reliability Metrics
2017	U.S. Department of Energy	*Valuation of Energy Security for the United States*	U.S. Department of Energy, Report to Congress. Available at https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29_1.pdf	Reliability Value Assessment – VoLL Methods

Year	Author	Title	Journal or Source	Document Focus
2016	Nateghi, R., Guikema, S.D., Wu, y., Bruss, B.	*Critical Assessment of the Foundations of Power Transmission and Distribution Reliability Metrics and Standards*	Risk analysis, Vol 36, No. 1, 2016: DOI: 10.1111/risa.12401. Available at https://www.researchgate.net/publication/276357284_Critical_Assessment_of_the_Foundations_of_Power_Transmission_and_Distribution_Reliability_Metrics_and_Standards_Foundations_of_Power_Systems_Reliability_Standards	Alternative Reliability Metrics
2016	Diskin, P.T., Washko, D.M.	*Pennsylvania Electric Reliability Report 2015*	Published by Pennsylvania Public Utility Commission. Available at http://www.puc.pa.gov/General/publications_reports/pdf/Electric_Service_Reliability2015.pdf	Reliability Reporting – Outage Causes
2016	GridSolar, LLC	*Final Report Boothbay Sub-Regions Smart Grid Reliability Pilot Project*	Prepared for Docket No. 2011-138, Central Maine Power Co., Request for Approval of Non-Transmission Alternative (NTA) Pilot Project of the Mid-Coast and Portland Areas January 19, 2016	Reliability Metrics – Alternative Reporting
2016	Ponemon Institute Research Center	*Cost of Data Center Outages*	Part of the Data Center Performance Benchmark Series, sponsored by Emerson Network Power. Available at https://planetaklimata.com.ua/instr/Liebert_Hiross/Cost_of_Data_Center_Outages_2016_Eng.pdf	Reliability Value Assessment- VoLL for Data Centers
2015	Schroder, T., & Kuckshinrichs, W.	*Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*	Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), Forschungszentrum Julich BMbH, Julich, Germany. Available at https://juser.fz-juelich.de/record/279293/files/fenrg-03-00055.pdf	Reliability Value Assessment – VoLL Methods
2015	Sullivan, M.J., Schellenber, J., Blundell, M.	*Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*	LBNL report funded by Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231., LBNL-6941E, January 2015. Available at https://emp.lbl.gov/sites/default/files/lbnl-6941e.pdf	Reliability Value Assessment – VoLL by Sector, Region and Duration
2014	Khujadze, S., Delphia, J.	*A Study of the Value of Lost Load (VOLL) for Georgia*	Report prepared for USAID Hydro Power and Energy Planning Project, Contract Number AID-OAA-I-13-00018/AID-114-TO-13-00006 Deloitte Consulting LLP. Available at https://dec.usaid.gov/dec/content/Detail.aspx?ctID=ODVhZjk4NWQtM2Yy	Reliability Value Assessment- VoLL Country Studies

Year	Author	Title	Journal or Source	Document Focus
			Mi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3	
2013	Pfeifenberger, J.P., Spees, K.	*Resource Adequacy Requirements: Reliability and Economic Implications*	Report prepared by Brattle for FERC. Available at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf	Reliability Value Assessment - Planning Reserve Margins
2013	London Economics International, LLC	*Estimating the Value of Lost Load*	Briefing paper prepared for the Electric Reliability Council of Texas, Inc. (June 17, 2013). Available at http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf	Reliability Value Assessment (Literature Review)
2012	Electric Reliability Council of Texas, Inc., Laser, W.	*Resource Adequacy and Reliability Criteria Considerations*	Presented at PUC Workshop: Commission Proceeding Regarding Policy Options on Resource Adequacy, July 27, 2012. Available at http://www.ercot.com/content/gridinfo/resource/2012/mktanalysis/ERCOT%20Presentation%20for%20PUCT%20July%2027%202012%20Workshop.pdf	Reliability Value Assessment - Planning Reserve Margins
2011	Rouse, G., Kelly, J.	*Electricity Reliability: Problems, Progress and Policy Solutions Galvin Electricity Initiative*	Galvin Electricity Initiative. Available at http://galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf	Reliability Metrics- Outage Reporting Metrics Review
2010	Centolella	*Estimates of the Value of Uninterrupted Service for the Mid-West Independent System Operator*	Available at https://sites.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf	Reliability Value Assessment – VoLL Midwest Study
2008	Ventyx	*Analysis of "Loss of Load Probability" (LOLP) at Various Planning Reserve Margins*	Available at https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Attachment-2.10-1-LOLP-Study.pdf	Reliability Metrics - LOLP and Planning Reserve
2006	LaCommare, K.H., Eto, J.H.	*Cost of Power Interruptions to Electricity Consumers in the United States*	LBNL-58164, Report funded by U.S. Department of Energy under Contract NO. DE-AC02-05CH11231. Available at	Reliability Value VoLL- Annual Total Costs by Sector and Region

Year	Author	Title	Journal or Source	Document Focus
			https://emp.lbl.gov/sites/all/files/report-lbnl-58164.pdf	
2004	LaCammara, K.H., Eto, J.H.	*Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.*	Ernest Orlando LBNL Environmental Energy Technologies Division. LBNL-55718. Report prepared by U.S. Department of Energy under Contract No. DE-AC03-76F00098. Available at https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Understanding_Cost_of_Power_Interruptions.pdf	Reliability Value Assessment – VoLL by Sector and Duration
2004	Chowdhury, A. A., Mielnik, T.C., Lawion, L.e., Sullivan, M.J., and Katz, A.	*Reliability Worth Assessment in Electric Power Delivery Systems*	Power Engineering Society General Meeting, 2004 (Denver: IEEE), 654-660.	Reliability Value Assessment – VoLL Midwest Study
2003	Lawton, L. Sullivan, M., Van Liere, K., Katz, A., & Eto, J.	*A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*	Prepared for Imre Gyuk Energy Storage Program, Office of Electric Transmission and Distribution U.S. Department of Energy. LBNL-54365. Available athttps://emp.lbl.gov/sites/all/files/lbnl-54365.pdf	Reliability Value Assessment – VoLL Sector, Region and Duration

APPENDIX J: GUIDE TO CALCULATING AVOIDED COSTS FOR CLEARED AND UNCLEARED MEASURES

This appendix provides a simplified explanation of the methodologies and applications of capacity and capacity DRIPE.[371] It uses a set of illustrative numbers to more simply describe the calculations underlying cleared and uncleared capacity and capacity DRIPE. It accompanies the "AppdxJ" tab of the *AESC 2021 User Interface*, which provides specific numbers for all years, states, and measure lives for the following avoided cost categories:

- Cleared capacity
- Uncleared capacity
- Cleared capacity DRIPE
- Uncleared capacity DRIPE
- Cleared reliability
- Uncleared reliability

This appendix is not intended to substitute the more in-depth explanations provided, which are provided in Chapter 5: *Avoided Capacity Costs*, Section 9.3: *Electric capacity DRIPE*, and Section 11.2: *Value of reliability: Generation component*. A few caveats about this summary:

- This section uses illustrative values only. We have selected values that superficially resemble Massachusetts' avoided costs.[372]
- We simplify some calculation steps for readability but provide footnotes where these steps are more complex in practice.
- We discuss avoided costs as applied to energy efficiency measures, but the avoided costs apply just as easily to demand increases (e.g., from electrification).
- The approaches below describe wholesale avoided costs. Further steps are needed to convert wholesale values to retail values. See Appendix B: *Detailed Electric Outputs* for additional instructions.

[371] This appendix replaces the 2018 version of Appendix J, which focused on "calculating benefits of uncleared capacity and uncleared capacity DRIPE for short- and medium-duration programs." We note that AESC 2018 described there being two separate LFE schedules for long-duration and shorter-duration measures. This is because for measure lives 10 years or greater, the LFE schedule is effectively same for the first 15 years of a measure lifetime (see the last column in Table 43). In the *AESC 2021 User Interface*, we explicitly calculate the uncleared resource effects for 35 different measure lives for the entire study period (2021 through 2055) and thus no longer need to make this simplifying assumption.

[372] Massachusetts is chosen as an example because it constitutes roughly half of New England's electricity demand.

Cleared capacity

Cleared capacity values in AESC represent the avoided cost associated with energy efficiency resources a program administrator has offered and cleared in ISO New England's FCM.

AESC estimates a capacity price for a future delivery year based on the capacity market (e.g., $2 per kW-month, equivalent to $24 per kW-year) as detailed in Chapter 5: *Avoided Capacity Costs*. This value is the avoided cost of cleared capacity. Program administrators then multiply this avoided cost by energy efficiency savings in that year (e.g., 10 MW) to determine the measure's annual benefit. In this example, the annual benefit is $240,000, after converting units. This is $240,000 that ratepayers would not otherwise spend to procure capacity in the capacity market. If the capacity price did not change year-to-year, this measure would provide $240,000 in benefits for every year the illustrative 10 MW measure is in place. The 10 MW measure would provide $1.2 million in benefits if the savings persisted for five years.[373]

Uncleared capacity

A program administrator may choose not to bid all of its energy efficiency portfolio's capacity savings into the capacity market, or it may be possible that a resource does not receive a capacity obligation but is nonetheless built. As a result, the savings from the "uncleared" amounts do not produce direct savings within the capacity market. However, these measures still provide indirect system benefits by impacting ISO New England's forecast of load, which is one of the inputs used to develop prices in the capacity market. See Section 5.2: *Uncleared capacity calculations* for more detail on this avoided cost category.

Because ISO New England's load forecast is based on 15 years of historical data, uncleared measures will eventually impact future load forecasts. However, it takes a few years of sustained savings before the uncleared measures impact the load forecast directly. At that point, the measure's impact can be generally described as a "ramp up" followed by a "fade out." We have created the "load forecast effect" (LFE) schedule to account for this market dynamic. The LFE schedule is a percentage factor that scales a measure's impact on future load forecasts. The percentage varies by calendar year and with the length of time an efficiency measure provides savings (i.e., measure life year).

Importantly, unlike cleared capacity, benefits from uncleared resources must be summed over the study period, rather than the measure life. This is because benefits do not accrue until after the measure has been in effect for a few years, and because benefits continue to accrue for several years after the measure ceases to be active, as the load reduction moves through the 15 years of data used in the ISO load-forecast regression. In AESC we calculate the stream of annual avoided uncleared capacity costs for each measure life within the study period.

[373] This is a simplified example. In practice, program administrators typically discount future benefits and apply transmission and distribution losses to convert wholesale avoided costs to retail costs. Capacity values also typically differ year-to-year. Similar caveats apply to the subsequent sections.

To calculate benefits from uncleared capacity resources, AESC uses the same capacity price calculated in "Cleared capacity," above. We then scale up this capacity price by the reserve margin (e.g., 15 percent) because, by reducing load, uncleared resources avoid the need to purchase additional supply reserves.[374] We further adjust the resulting value to account for the delayed impact on the load forecast (i.e., the LFE). If we now assume that the 10 MW measure from our above example is uncleared, then the uncleared capacity avoided cost is equal to the product of (a) the capacity price at $24 per kW-year, (b) one plus the reserve margin or 1.15, and (c) the LFE (which varies by year and measure life). For years when the LFE is 100 percent, the resulting avoided cost is $27.6 per kW-year. For a 10 MW measure, this implies benefits in that year of $276,000. Because the LFE varies over time, undiscounted lifetime benefits are $1.4 million.

Viewed in isolation, uncleared capacity resources have a larger value than cleared capacity resources. This is because the cleared resources only provide benefits in the years that the measure is active and participating in the capacity market, whereas uncleared resources provide benefits (even at a reduced level) for several years after the measure ceases to provide savings. Uncleared capacity resources are also larger because they include an avoided reserve margin. Because many of the uncleared capacity benefits accrue in the mid- to far-future, but the cleared capacity benefits accrue in the near-term, applying a discount rate could cause the uncleared capacity benefit (in this hypothetical example, $1.4 million) to be equal to or perhaps less than the cleared capacity benefit (here, $1.2 million).

Cleared capacity DRIPE

DRIPE describes the phenomenon wherein 1 MW of savings not only avoids a purchased quantity, but also changes the price that all purchasers in the capacity market pay for capacity. Cleared capacity DRIPE, specifically, represents the price effects on the capacity market from measures bid into the capacity market. These effects can be further subdivided into two categories: benefits to consumers within the state where the measure is installed (intrazonal effects) and benefits to consumers outside of the state where the measure is installed (interzonal effects). AESC translates these price effects (which describe how the system's prices change as demand changes) into DRIPE values (which describe the benefits that accrue to any one measure due to this price effect). See Chapter 9: *Demand Reduction Induced Price Effect* for more background on the concept of DRIPE and Section 9.3: *Electric capacity DRIPE* for more details about capacity DRIPE in particular.

Cleared capacity DRIPE is calculated as follows: first, the "price shift" is estimated. The price shift represents how the capacity price would change if 1 fewer MW of capacity were required. It is calculated by examining the supply curves observed by ISO New England, and calculating the slope of

[374] Uncleared measures are effectively "counted" in the demand side of the capacity auction (i.e., within the load forecast). In contrast, cleared measures are effectively treated the same as conventional power plants (i.e., supply), and through the auction require the purchase of some extra amount of capacity to act as a reserve margin. We increase the uncleared capacity benefit by a value equal to one plus the reserve margin to reflect changes on the demand side of the market.

each line segment between each auction round.[375] This price shift is measured in terms of capacity price per unit demand, or $/kW-month per MW. These price shifts are generally very small numbers. For example, the price shift might be $0.001/kW-month per MW, or $0.012/kW-year per MW.[376]

Second, we multiply these price shifts by the capacity requirement for each state because the price effect impacts resources throughout in the FCM, not just the efficiency resources responsible for the price shift. However, we assume that only a subset of these resources are subject to the price shift. Load-serving utilities purchase some amount of their capacity outside of the FCM to mitigate the risk of price volatility in the capacity market—i.e., as a financial hedge. In AESC, we only consider the "unhedged" portion of the capacity requirement that is bought via the capacity market would be impacted by DRIPE effects.[377]

Finally, we apply an annual decay schedule. AESC assumes the price effect fades out over time as retail prices fall (encouraging higher load), existing resources retire, and new potential resources are abandoned. As a result, price effects are fully realized in the year of installation, but completely phased out six years later. The benefit of cleared capacity DRIPE decays over time, but that decay does not change with the efficiency resource's measure life (unlike the LFE schedule used for uncleared capacity and uncleared capacity DRIPE, which changes with the measure life).

If we assume that our example state has 10,000 MW in unhedged capacity requirement, multiplying this by the $0.012/kW-year per MW price effect from above yields a value of $120 per kW-year. Scaled by the decay effect, this value will be $120 per kW-year in years with no decay and $0 per kW-year in subsequent years with full decay. This is then the avoided cost for cleared capacity DRIPE.

As with cleared capacity, the effects of cleared capacity DRIPE should be summed over the measure lifetime, rather than the study period. As our 10 MW measure lasts for five years, we find that it produces undiscounted intrazonal DRIPE benefits of $4.0 million. Assuming our example state's 10,000 MW of unhedged demand is exactly half of the regional unhedged capacity requirement, the interzonal DRIPE benefits are also $4.0 million, without discounting. Total cleared capacity DRIPE benefits are the sum of these two values, or $8.0 million.

Uncleared capacity DRIPE

Uncleared capacity DRIPE is the price-shifting benefit that accrues to measures not bid into ISO New England's FCM. Even though these measures are outside the capacity market, they impact the load

[375] We assume that all future supply curves have the same shape as the most recent capacity auction, but shifted to account for changes in supply. In AESC 2021, this is FCA 15.

[376] Price shifts may change year-to-year as the corresponding year's capacity price changes position on the supply curve.

[377] In practice, over a long enough period, prices paid for hedged capacity ought to converge to the market price. Because our estimates of DRIPE exclude this hedged amount, they can be considered a conservative estimate.

forecast inputs, and thus provide uncleared capacity DRIPE benefits. As with cleared capacity DRIPE, there are both intrazonal and interzonal benefits.

For the most part, uncleared capacity DRIPE is calculated the same as cleared capacity DRIPE. We begin with a price shift observed from the latest FCA (e.g., $0.0012/kW-year per MW), which is then multiplied by a zone's unhedged capacity requirement (e.g., 10,000 MW). This $120 per kW-year result is the avoided cost. But there are two key differences compared to cleared capacity DRIPE.

1. First, uncleared capacity DRIPE utilizes an LFE schedule. For uncleared capacity DRIPE, we assume the load forecast and thus the capacity market gradually incorporates the impacts of uncleared load reductions (just like with uncleared capacity). This effect persists for some period before the market readjusts, and the DRIPE benefit fades out. This LFE schedule is based on the one used for uncleared capacity, but is adjusted to reflect a decay in DRIPE benefits over time. This is the same decay schedule used for capacity DRIPE. As with uncleared capacity, this LFE schedule varies depending on measure lifetime.

2. Second, because uncleared capacity DRIPE results from a reduction in the load forecast rather than the addition of capacity, we multiply these benefits by a factor of one plus the reserve margin.

The annual intrazonal uncleared capacity DRIPE is equal to the product of (a) the price shift in that year, (b) the zone's unhedged capacity requirement for that year, (c) one plus the reserve margin, and (d) that year's LFE value. Interzonal uncleared capacity DRIPE is calculated the same way but uses the regional unhedged capacity requirement, less the unhedged capacity requirement for the zone in question.

As with uncleared capacity, uncleared capacity DRIPE benefits are summed over the study period (rather than the measure life), as benefits continue to accrue years after the measure has been installed and expires.

In our continued example, undiscounted intrazonal uncleared capacity DRIPE benefits are $3.7 million, while interzonal uncleared capacity DRIPE benefits are also equal to $3.7 million. Total uncleared capacity DRIPE benefits are $7.5 million.

Cleared reliability

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.

To calculate cleared reliability benefits, we first estimate four values:

- First, VoLL is the cost experienced by customers during an outage. It is determined through a review of the literature. In AESC 2021, we estimate this value at $73 per kWh.

- Second, we estimate the change in MWh of reliability benefits per megawatt of reserve. This is calculated by observing the slope of the demand curve used in the FCA at the point of the clearing price. A typical value might be 0.2 MWh per MW.
- Third, we derate reliability benefits based on the fact that bidding in an additional MW into the FCA at $0 per kW-month price shifts the supply curve to the right and shifts out some smaller amount of capacity that would otherwise have cleared. As a result, the amount of cleared supply increases by just a fraction of the additional supply. This value is determined by examining the percentage difference in slopes of the demand curve and supply curve at the point of the clearing price. A typical value might be 20 percent.
- Finally, we assume a decay effect. We use the same decay effect that is applied to cleared capacity and uncleared capacity due to similar expected dynamics in market response.

We then multiply these four values against one another to estimate the avoided cleared reliability cost in each year the resource is active. Cleared reliability benefits do not differ based on measure life.

Using the same example as above (a 10 MW measure with a five-year lifetime), we would expect cleared reliability benefits of about $0.01 million. Reliability benefits are much smaller than benefits provided by other avoided cost categories.

Uncleared reliability

Resources that do not clear in the capacity market may still provide a reliability benefit. 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. In addition, resources that do not clear in the capacity market or immediately affect the load forecast will increase reserve margins and contribute to improved reliability.

To calculate uncleared reliability benefits, we first estimate five values:

- First, just as with cleared reliability, we utilize a VoLL. The VoLL in AESC 2021 is $73 per kWh.
- Second, just as with cleared reliability, we estimate the change in MWh of reliability benefits per megawatt of reserve. A typical value might be 0.2 MWh per MW.
- Third, we gross up benefits to reflect the reserve margin, as these resources are not resources bid into the capacity market and thus reduce supply.
- Fourth, we assume that reliability has a phased effect. Measures provide a reliability benefit as soon as they are installed. This benefit persists for a period of time then fades out.

- Fifth, we assume a separate decay effect that reflects the fact that after a period of time, all the of the reliability benefits will have been captured in the load forecast.

We then multiply these five values against one another to estimate avoided uncleared reliability costs. Uncleared reliability differs from the other uncleared avoided cost categories in two ways:

- Unlike uncleared capacity and uncleared capacity DRIPE, uncleared reliability benefits are summed over the years in which the measure is active, rather than the entire study period. This is similar to how avoided costs are summed for cleared reliability and most other avoided cost categories.
- Uncleared reliability benefits do not differ based on measure life.

Using the same example as above (a 10 MW measure with a five-year lifetime), we would expect cleared reliability benefits of about $0.8 million. Generally speaking, uncleared effects are greater than cleared effects because they are not impacted by the net increase in cleared supply variable (which only affects resources that clear the market).

Applying these values

For a portfolio of measures, a program administrator may bid only a share of its capacity savings into the capacity market. In these situations, the program administrator should split the cleared and uncleared savings and calculate benefits accordingly. In our example, if a program administrator bids into the capacity market 50 percent of its 10 MW portfolio of measures, it would provide $600,000 in undiscounted cleared capacity benefits and $690,000 in uncleared capacity benefits (e.g., each of the values calculated above is halved). Likewise, the portfolio of measures provides $4.0 million in cleared capacity DRIPE benefits and $3.7 million in uncleared capacity DRIPE benefits (again, the above values are halved). Reliability benefits are much smaller: this example would yield cleared reliability benefits of $0.05 million and uncleared reliability benefits of $0.4 million.

In practice, (a) measures have different measure lives, (b) each of these avoided cost categories have different decay or LFE schedules, (c) values change over time, and (d) program administrators utilize a discount rate. As a result, program administrators must take a weighted average by measure-life year over the study period, not calendar year. Separate cost streams for cleared capacity, uncleared capacity, cleared capacity DRIPE, uncleared capacity DRIPE, cleared reliability, and uncleared reliability should be calculated independently for each cleared or uncleared MW (or share of MW).

Capacity vs. capacity DRIPE

At first glance, capacity DRIPE benefits may appear surprisingly large relative to capacity benefits. But, changing the price of capacity is a high-value action, because it reduces the cost of procuring capacity for <u>all</u> resources in the system, not just the energy efficiency resources instigating the price change.

For example, assume total unhedged capacity cleared in New England is 20,000 MW, all of which clears at $2 per kW-month. This implies a total annual market value is $480 million. If our 10 MW measure were entirely bid into the capacity market, it would produce $0.24 million in capacity benefits in one year. This is about 0.05 percent of the market's total value, and represents a one-for-one switch between one type of capacity (energy efficiency) for another kind (e.g., a conventional fossil resource).

But, because of price-shifting effects, the cleared measure also lowers the price that other market participants pay for the 20,000 MW. By lowering the price for all 20,000 MW, this measure produces annual cleared capacity DRIPE benefits of $2.4 million, or 0.5 percent of the $480 million total market value (e.g., one order of magnitude larger than the capacity benefit).

These are both small numbers, relative to the size of the market. But because the DRIPE effect is multiplied across 20,000 MW, rather than just 10 MW, the final benefit is larger.

Scaling factor for uncleared resources

Energy efficiency measures generally save energy according to a consistent pattern throughout a year (i.e., its load shape) because they perform the same functions as the less efficient technology while using less energy. Alternatively, demand response resources are designed to provide savings during specific time periods depending on grid characteristics that vary by year, day, and hour. Demand response resources are often subject to customer responsiveness, which can fluctuate with a customer's annual participation in a demand response program and with each demand response event called. As a result, demand response resources typically have shorter and more variable durations, both in terms of measure lives and annual hours of operation. Because of this variability, uncleared measures may not have a "full" effect on the load forecast. This implies that their uncleared benefits should be scaled according to how frequently the measure is expected to operate (and, as a result, impact the load forecast).

To account for demand response's limited impact on the load forecast, AESC recommends that program administrators apply a scaling factor that adjusts uncleared capacity, uncleared capacity DRIPE, and uncleared reliability benefits. The scaling factor is a measure-specific percentage multiplier that should be estimated based on a demand response program's design, implementation, and participant responsiveness. See text in the following section, Appendix K: *Scaling Factor for Uncleared Resources*, and the accompanying workbook titled "Appendix K.xlsx" for more information on how to calculate this scaling factor for different measures.

We note that the scaling factor should not be applied to reliability values.

APPENDIX K: SCALING FACTOR FOR UNCLEARED RESOURCES

This appendix repeats text originally found in the April 2019 report titled, "The Effect of Uncleared Capacity Load Reductions on Peak Forecasts." This report was authored by Resource Insight, Inc. with assistance from Synapse Energy Economics, Inc., and was originally commissioned by National Grid as a supplemental study to AESC 2018.[378] This document was accompanied by a "DR Coefficient Calculator" workbook, which program administrators can use to evaluate how uncleared capacity DRIPE benefits should be adjusted for measures that operate in only some hours of the year.[379]

Text and analysis in this appendix have not been updated, with the following exceptions:

- The addition of a "Purpose" section summarizing the intended use of this appendix
- Some edits to text to improve readability and consistency with the rest of the AESC 2021 text
- Cross-references to parts of the main AESC 2021 text
- Several modifications and corrections to the DR calculator

Analytical updates to this document were not scoped within AESC 2021; however, we do not expect these values to be substantially different than those calculated in the original 2019 report because ISO New England's load forecasting techniques have not changed substantially.

Purpose

This document describes the methodology for creating a scaling factor that adjusts the benefits provided by uncleared resources. It also provides a calculator workbook so that program administrators may create this scaling factor for themselves. This workbook is the file titled "Appendix K.xlsx."

It is only for resources that are not expected to provide a capacity benefit throughout the summer period (we focus on summer, because it is summer demand that drives the capacity market). For example, this factor is useful for demand response measures that may only be active some summer days. But it is not applicable to resources like energy efficiency that are assumed to provide savings at a more-or-less consistent level throughout the summer.

Program administrators wishing to use this appendix will want to use the Appendix K workbook to estimate the appropriate scaling factor for their DSM resource. This factor is then multiplied by the

[378] Chernick, P., P. Knight, M. Chang. April 22, 2019. *The Effect of Uncleared Capacity Load Reductions on Peak Forecasts.* Synapse Energy Economics prepared for National Grid. Available at https://www.synapse-energy.com/sites/default/files/The_effect_of_load_reductions_on_peak_forecasts.pdf.

[379] See original version at https://www.synapse-energy.com/sites/default/files/DR_Coefficient_Calculator%20%282%29.pdf.

uncleared capacity or uncleared capacity DRIPE avoided cost (calculated using the *AESC 2021 User Interface*) and the measure's capacity savings and seasonal coincidence factor to provide the final benefit value.[380]

This scaling factor is not applicable to cleared capacity, cleared capacity DRIPE, cleared reliability, uncleared reliability, or any other avoided cost category.

Introduction

This appendix describes our analysis of the effects of load reductions on a varying number of days per year over a varying number of years. This analysis included the construction of a regression model to mimic the ISO New England forecast model and the variation of the historical data to determine the effect of targeted load reductions for the FCAs. We interpret these effects as having an impact on the future value of uncleared capacity and uncleared capacity DRIPE.

Our modeling indicates that a load reduction program that occurs on even a single peak day each summer can affect the load forecast used in the FCA. In most situations, the load forecast will fall more if the historical load is reduced for more days per year or for more years. Regardless of the number of days that a program reduces load annually, the reduction in the load forecast rises steadily for at least eight years. If the program reduces load on less than 55 days, the forecast reduction continues to increase until the program has been running for 12 days. For programs that reduce load on less than 13 days annually, running the program for more years continues to depress the load forecast further, up to the 15 years' worth of historical data that ISO New England uses to develop each load forecast.

This implies that resources that do not provide load reductions on every day of the summer period should have reduced values for uncleared capacity and uncleared capacity DRIPE, relative to the values estimated in the *AESC 2021 User Interface*.

Background

This issue is specific only to uncleared resources.[381] For example, these may include demand response programs, behavioral programs, or rate-design initiatives that are not eligible capacity resources. Although uncleared resources do not receive capacity payments, they reduce the aggregate amount of

[380] We note that there may be certain situations when a dispatchable resource (such as demand response or storage) is cleared in the capacity market, but also performs in such a way that creates uncleared capacity benefits. These additional uncleared benefits are likely to be small, as the most likely the way for them to occur is for a resource to operate for a limited number of hours, during periods that are less important to the formulation of ISO New England's load forecast regression. Calculations to estimate these benefits are complex, dependent on the specific program being analyzed, and may be impossible to calculate without obtaining more specific load regression data from ISO New England. As a result, we do not perform this estimate in AESC 2021. Future editions of this study or follow-up supplemental studies may examine this issue in closer detail.

[381] This includes any resources or portions of resources that are not bid into the FCA or are bid into FCAs but do not clear the auction.

capacity that is required, and hence the price of that capacity, by reducing the ISO New England peak load forecast used in the FCA for that year (see Section 5.2: *Uncleared capacity calculations* for a longer discussion of this dynamic).

The quantity and price of the capacity obligations acquired in the FCA of a particular year (year *t*) depend on the forecast prepared in the previous year (*t* – 1). That forecast is built upon a regression analysis constructed from daily historical data from each of the 62 days in July and August for the previous 15 years (*t* – 16 to *t* – 2), which consists of 930 data points.[382] The regression formulation for the forecast may vary from year to year, but appears to consistently include multiple independent variables computed from a weighted temperature-humidity index (WTHI), including an annual time trend times WTHI and the gross energy forecast (before energy efficiency and BTM solar PV).

Although we consulted with ISO New England on its forecast data, ISO New England did not provide us with its proprietary demand model data or any details on the functional form of its regression model, beyond those in the Forecast Data summaries provided on the ISO New England web site.[383] As a result, our analysis reconstructs a proxy ISO New England load forecast. We then use this to quantify the impact different load reductions over different time periods and under different conditions.

The reference regression model

We constructed our proxy for the ISO New England forecast model based on the data used in the 2017 CELT forecast, which was used in FCA 12 to procure capacity for the summer of 2021.[384] Importantly, all of the effects described below for the reference regression model are for load reductions of various numbers of years that would have been used in producing the 2017 CELT forecast for summer 2021, which was the basis for the demand curve used in FCA 12. Other regressions performed using data for other years could provide different results. A one-year load reduction would affect only the 2016 summer peak day(s), a two-year reduction would affect 2015 and 2016, a three-year reduction would affect 2014–2016, and a 15-year reduction would reduce peaks in 2002–2016.

Input data

Since we did not have ISO New England's exact data, we needed to develop a proxy dataset. As a result, our analysis should be interpreted as an estimate of load reduction effects *based upon data and using a model similar* to that currently used by ISO New England. We do not claim that our model is a precise

[382] Discussions with ISO New England after the completion of this supplemental study confirmed that the forecast is solely built on summer peak hours. Winter peak hours are not included.

Knight, P., M. Chang, J. Hall. May 1, 2020. *AESC Supplemental Study Part I: Considering Winter Peak Benefits*. Synapse Energy Economics for Massachusetts Electric Energy Efficiency Program Administrators. Available at https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_I_Winter_Peak.pdf.

[383] This data includes ISO New England's computation of daily WTHI and reconstitution of load for peak-hour energy-efficiency reductions, demand response and OP #4 measures, and behind-the-meter solar output.

[384] FCA 12 was conducted in February 2018 and was the most recent FCA conducted at the time of this analysis.

prediction of future ISO New England forecasts. Since ISO New England's data and its model structure change (at least a little) every year, we cannot anticipate the exact form of the ISO New England load forecast model for any specific future year.

Development of proxy data

First, we made a number of assumptions to generate our proxy historical dataset, which may not necessarily match ISO New England's past and future sources and methodology.

The dependent variable in the regression analysis is the daily gross peak demand. This is the actual daily peak demand, plus the effects of BTM solar PV and energy efficiency programs (referred to as PDR by ISO New England) for both peak demand and energy, as well as the effects of Operation Procedure #4 (OP #4) events and load management on peak (which is available only for the summer and winter peaks). [385, 386] Our understanding is that ISO New England uses a proprietary data service to estimate the output of installed solar capacity in each historical hour, while assuming that every hour's PDR reduction is equal to the PDR resource cleared in that capacity delivery year.

We estimated historical daily gross peak load as the sum of (a) the maximum hourly demand for the day in ISO New England's hourly load data files and (b) the summer peak PV and PDR reported in the ISO New England's 2017 Forecast Data spreadsheet for the year. [387, 388] We computed the gross monthly net energy for load (NEL) by multiplying the historical monthly sum of actual load by the ratio of gross annual energy to net annual energy from the ISO New England 2017 Forecast Data.[389]

We computed the ISO New England temperature-humidity index (THI) for each day (0.5 × dry-bulb temperature + 0.3 × wet-bulb temperature + 15) as the weighted average of the THI's (the "WTHI") from

[385] Actual daily peak demand is available from the ISO New England website.

[386] ISO New England. March 4, 2021. "ISO New England Operating procedure No. 4 – Action During a Capacity Deficiency" Iso-ne.com. Available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

[387] ISO New England. Last accessed March 10, 2021. "Energy, Load, and Demand Reports." *ISO-ne.com.* Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/sys-load-eei-fmt.

[388] CELT 2017 Forecast Data File, Tab 5, WN. CELT 2017 was analyzed, as it was the projection used as the basis of the 2018 AESC Study.

[389] CELT 2017 Forecast Data File, Tab 1, History, Gross ISO-NE Coincident Summer Peak.

eight weather stations around the region.[390] We then computed the WTHI for each day using ISO New England's formula (weights of 10 for today's THI, 5 for yesterday's THI, and 2 for the previous day).[391]

Model specification

We estimated the historical relationship of gross load to WTHI, time, NEL and other variables with an ARIMAX (Auto-Regressive Integrated Moving-Average model with eXogenous variables) regression model.[392] This model incorporates both exogenous variables (e.g., net energy for load, weather) and the autoregressive error terms that ISO New England uses in its regression model. These are summarized in Table 178.

Table 178. Variables used in summer peak model

Variable	Definition
Intercept	Constant Term
PEAK	Daily Peak Load, MW
MA_NEL	12-month Moving Sum Annual Net Energy for Load, GWh
WTHI_SQ	The square of [the 3-day Weighted Temperature-Humidity Index at Peak– 55°]
TIME_WTHI	Year indicator; (2002=11, …, 2016=25) × WTHI
Weekend_WTHI	WTHI for a weekend day, else 0
July_04WTHI	WTHI for July_4, else 0
HOLWTHI	WTHI for a Holiday, else 0
Yr2005	1 if Year=2005; 0 otherwise
Yr2012	1 if Year=2012; 0 otherwise
AR(1)	Correction for autocorrelated error from the previous year
AR(2)	Correction for autocorrelated error from the two years previously

Note: This reproduces the description of the summer peak model in the Peak Definitions in ISO New England's 2017 Regional and State Energy & Peak Model Details, corrected to reflect conversations with the ISO forecasters and the specific model described in the Summer Peak Models tab of the Model Details.[393]

[390] The Notes sheet of the annual *SMD Hourly.xlsx* file provide the following weights for the weather stations: Windsor Locks CT (27.7 percent); Bridgeport CT (7 percent); Boston MA (20.1 percent); Burlington VT (4.6 percent); Concord NH (5.8 percent); Worcester MA (21.4 percent); Providence RI (4.9%); Portland ME (8.5 percent). We used the same weights for all years; we have not been able to confirm whether ISO New England has changed the weights over time, as load (especially summer peak) has increased in northern New England compared to the southern portion of the region.
Iowa State University. March 11, 2021. "Dry Line Over Iowa." *Iastate.org*. Available at https://mesonet.agron.iastate.edu/.

[391] Forecast Modeling Procedure for the 2018 CELT, May 1, 2018, page 9. https://www.iso-ne.com/static-assets/documents/2018/04/modeling_procedure_2018fcst.pdf. Note that this document contains all citations for coefficients and weights used in this analysis.

[392] Statmodels. Last accessed March, 10, 2021. *Statsmodels.org*. Available at https://www.statsmodels.org/devel/generated/statsmodels.tsa.statespace.sarimax.SARIMAX.html.

[393] The ISO New England forecast documentation sometimes refers to gross loads as net of PV and PDR, and the Forecast Modeling Procedure for 2017 CELT describes the composite time variable as using WTHI–55º, while the 2017 Regional and State Energy & Peak Model Details file suggests that WTHI is not reduced by 55º.

Independent variables included:

- Net Energy for Load, grossed up for PV and energy efficiency, over the 12 months ending in the current month (July or August, depending on the data point).
- The 3-day weighted temperature-humidity index (WTHI) for the eight cities used in ISO New England's own modeling of weather (see footnote 390). In our analysis, following the treatment in the ISO New England model, the WTHI variable is used as the square ($[\text{WTHI}–55]^2$), and as various cross terms, such as WTHI × weekend dummies.
- Year × (WTHI–55), where the year index is the calendar year minus 1991.
- Boolean flags (i.e., dummies) for holidays, July 4th, weekends, the years 2005 and 2012, and WTHI times the dummy variables for weekends, holidays and July 4th.[394]

These variables were defined for each July and August day in 2002 through 2016.

Forecast data

Once we developed the regression equation, we required forecast input values for the equation. One such input is a forecast of gross energy for load, which ISO New England provides in its forecast.[395] A second set of inputs entails time trend and binary variables: for time trend, we observe that 2017 is year 26, 2018 is year 27, and so on. For binary variables, the weekend binary equals WTHI on future Saturdays and Sundays, the July 4 and holiday binaries equal WTHI on July 4 each year.

ISO New England's forecasting method does not use a single WTHI value, but instead identifies the highest load for a variety of input conditions:

> Weekly peak load forecast distributions are developed by combining output from the daily peak load models with energy forecasts and weekly distributions of weather variables over 40 years.
>
> The expected weather associated with the seasonal peak is considered to be the 50th percentile of the top 10% of the pertinent week's historical weather distribution. The monthly peak load is expected to occur at the weather associated with the 20th percentile of the top 10% of the pertinent week's weather distribution. The "pertinent week" is the week of the month or season with the most extreme weather distribution. For resource adequacy purposes, peak load distributions are developed for each week of the forecast horizon.[396]

[394] It is unclear why ISO New England included variables for both holidays and July 4th, since the only holiday in the two summer months is July 4th. We used the two redundant variables; collectively, the two dummies should capture the effect of July 4th. It is also not unclear why the years 2005 and 2012 featured Boolean flags.

[395] 2017 Forecast Data File, Tab 6, Monthly NEL.

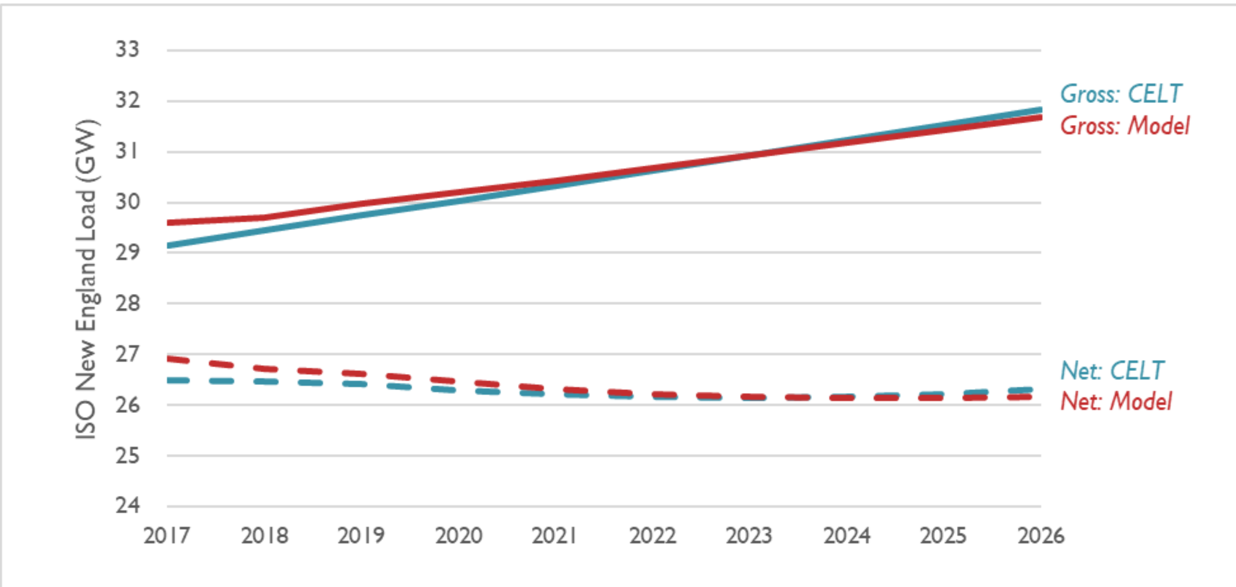
[396] Forecast Modeling Procedure for the 2018 CELT, May 1, 2018, p. 6.

We do not have access to the distributions that ISO New England used in this method, nor do we have a clear operational description of the method. Therefore, we performed a calculation to estimate a value of WTHI that best reproduced the 2017 CELT peak forecast, which turned out be 81.4°.

Base forecast benchmarking

Figure 64 summarizes our modeled Gross and NET 2017 forecast against the 2017 reported Gross and NET CELT forecast. Our modeled forecasted peak demands closely match the ISO's 2017 CELT forecast. Our forecasts for gross peak are within 0.2 percent of the 2017 CELT forecast for 2021, the year for which the 2017 forecast determined the installed capacity requirement.

Figure 64. Comparison of forecasts of gross and net Summer Peak, 2017 CELT and Resource Insight modeled proxy



The effect of load reductions on the forecast

The following sections describe our methodology and findings. We also describe a set of sensitivities that were analyzed to provide robustness for our results.

Structure of reductions

Using our constructed base forecast, we estimated how various load reductions in 2002 through 2016 would have affected the ISO New England load forecast for 2021. Each sensitivity run for the analysis consisted of four steps:

1. Reduce historical gross peak demands on a specified number of summer event days (d) for a specified number of years (y) by a constant number of MW (ΔL).

2. Estimate new regression model coefficients using the same functional form and the modified historical data.
3. Develop peak demand forecasts for the years 2017–2026 (and most importantly, 2021) using the new coefficients.
4. Compute the ratio (*R)* of the change between forecast peak (Δ*F*) to the load reduction (Δ*L*).

The ratio *R* can be thought of as a measure of the efficiency of load reduction in reducing the forecast.

For *ΔL*, we tested load reductions of 250 MW, 500 MW, and 1,000 MW. We used the same reduction in all the days and all the years adjusted in any particular run.

For *d*, we reduced load on the highest days, from one event day to all 62 summer days per affected year. We tested reductions on the highest-load days and the highest-WTHI days and looked at the effect of imperfect forecasting of peak days.

For *y*, we reduced load on the most recent years, from just one year (2016) to all 15 years 2002–2016.

The effect of lower input values on regression forecasts

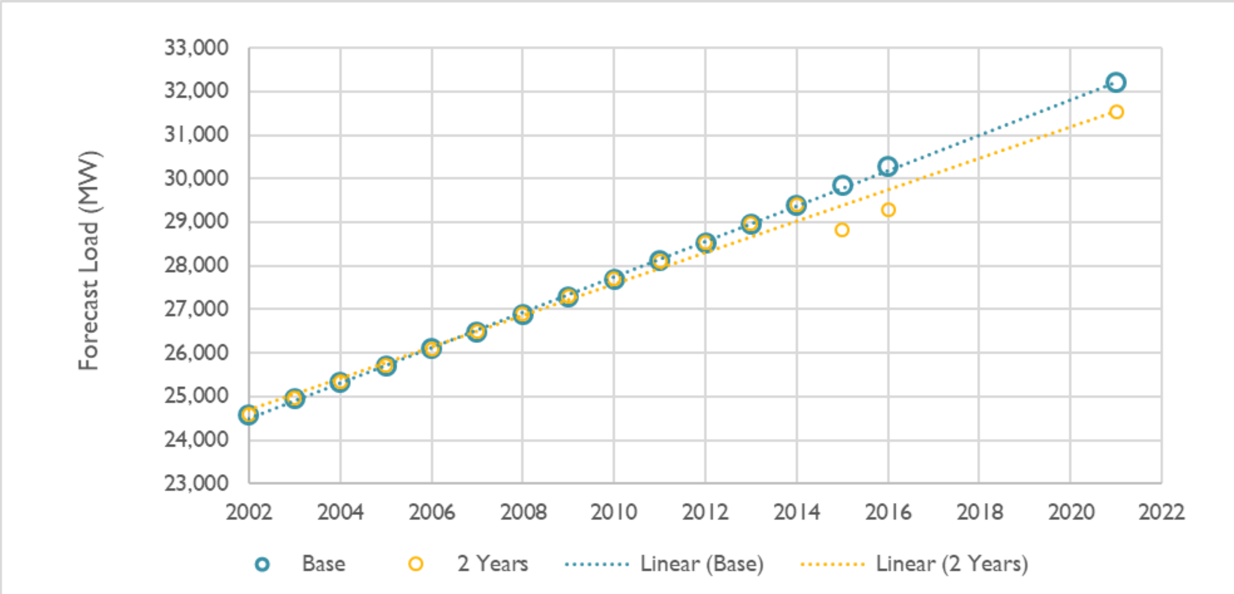
When we began this analysis, we expected that reductions on more days, and reductions in more years, would consistently push down the forecast further. As we discuss in the next section, that is not what we found. Before presenting our results, we will explain how they can arise.

The next four figures show a regression through 15 years of base data. In these examples, we assume a constant 1.5 percent annual growth.[397] In each figure, we show the base historical data, the linear trend line with the base data, the historical data that would have been observed with 1,000 MW reductions in some years, and the regression trend line with the modified data. For each figure, we identify how the change in load impacts the regression and the projection of 2021 load in particular.

The first figure, Figure 65, shows the effect of load reductions in the last two years of data, representing a demand response program operating in 2015 and 2016. The trend line tilts so that the trend is higher than the actual load in the first few years and in the last two years (the two years with demand response reductions), but lower than the input data for 2008–2014. The projection for 2021 is about 700 MW lower than in the base case.

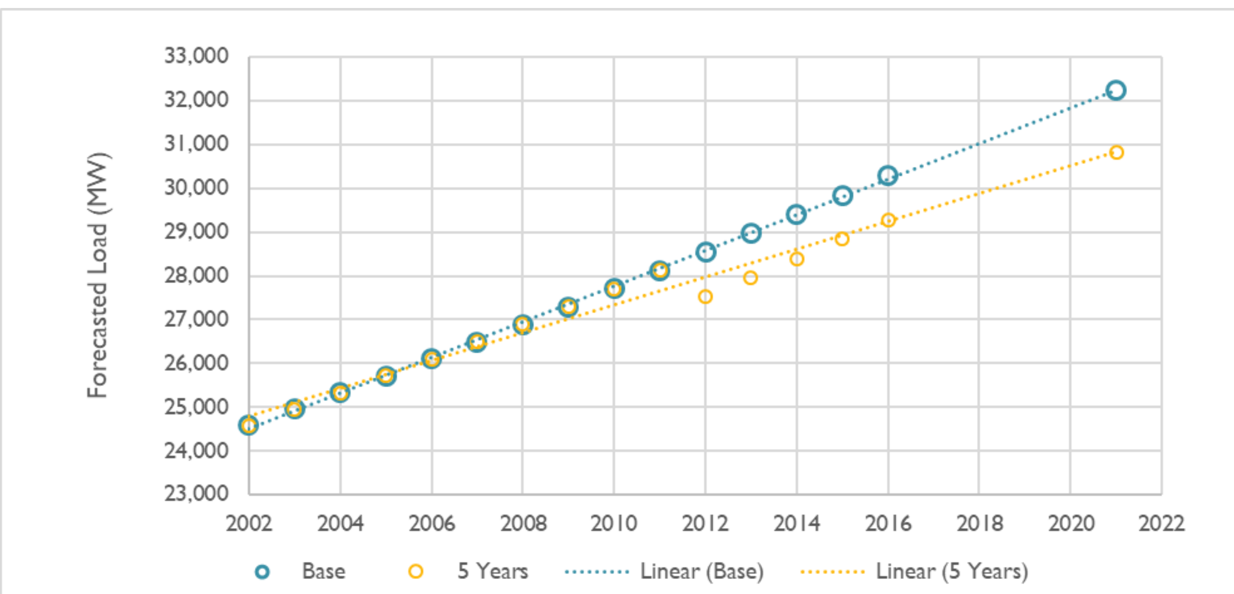
[397] A comparable analysis using weather-normalized loads before PDR and PV for 2002 through 2016 produced very similar results. But, due to a drop in load associated with the 2009-10 Great Recession, it is more difficult to read. We use a simplified example here.

Figure 65. Effect of two years of demand response on the forecast



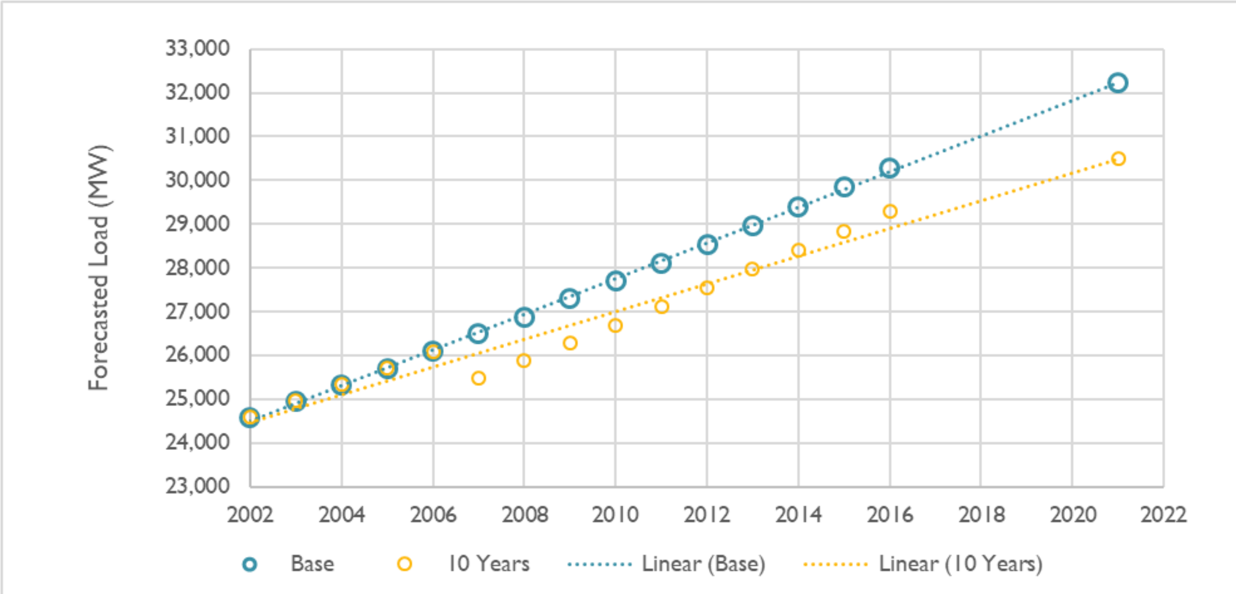
Next, Figure 66 shows the effect of five years of demand response reductions. The trend line with the demand response has tilted further, so that it is almost 1,000 MW below the base-case trend by 2016, and 1,400 MW below the base-case forecast for 2021. The trend line mostly rotates clockwise, rather than moving down, so the change from the base case increases over time and the reduction in the 2021 forecast is substantially larger than the reduction in loads in the five years affected by demand response.

Figure 66. Effect of five years of demand response on the forecast



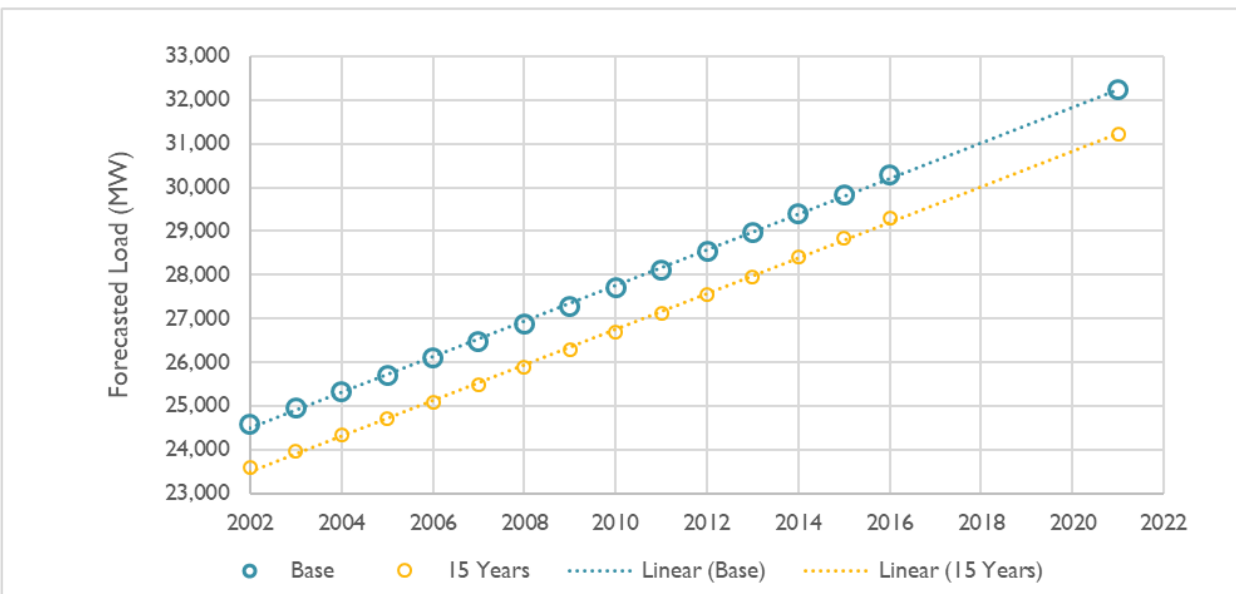
Third, Figure 67 shows the effects of nine years of demand response, which continues the pattern in Figure 66; the forecast for 2021 would be almost 1,800 MW below the base case.

Figure 67. Effect of nine years of demand response on the forecast



Finally, Figure 68 shows that 15 years of 1,000-MW load reductions lowers the trend line by 1,000 MW, while leaving the slope the same as in the base case. The forecast for 2021 is thus 1,000 MW lower than in the base case.

Figure 68. Effect of 15 years of demand response on the forecast



Thus, demand response in some number of the latest years will tend to produce forecast reductions that exceed the annual reductions in the historical data. Beyond some point, additional years of demand response will result in smaller forecast reductions, and once the demand response effect has been in effect for the entire study period, the forecast reduction will equal the reduction in the annual input data.

The same pattern would be expected as the reductions are extended to more of the highest-load days in each year.

Results for reductions on highest-load days

Not surprisingly, we found that the decreases in the forecast peaks based on load reductions varied with (a) the number of days on which load was reduced each year and (b) the number of years of load reductions in the historical load data. Interestingly, we found that the size of the load reduction had essentially no effect on the ratio of forecasted load reduction to historical load reduction, or as we have named it, the ratio *R*. For example, we observe that if load is reduced 100 MW on the five highest-load days in each of the last five summers in the modeling dataset (2012–2016), the forecast for 2021 would be reduced by 24 MW; if the reductions in the historical load were 1,000 MW, the forecast would be reduced by 240 MW.

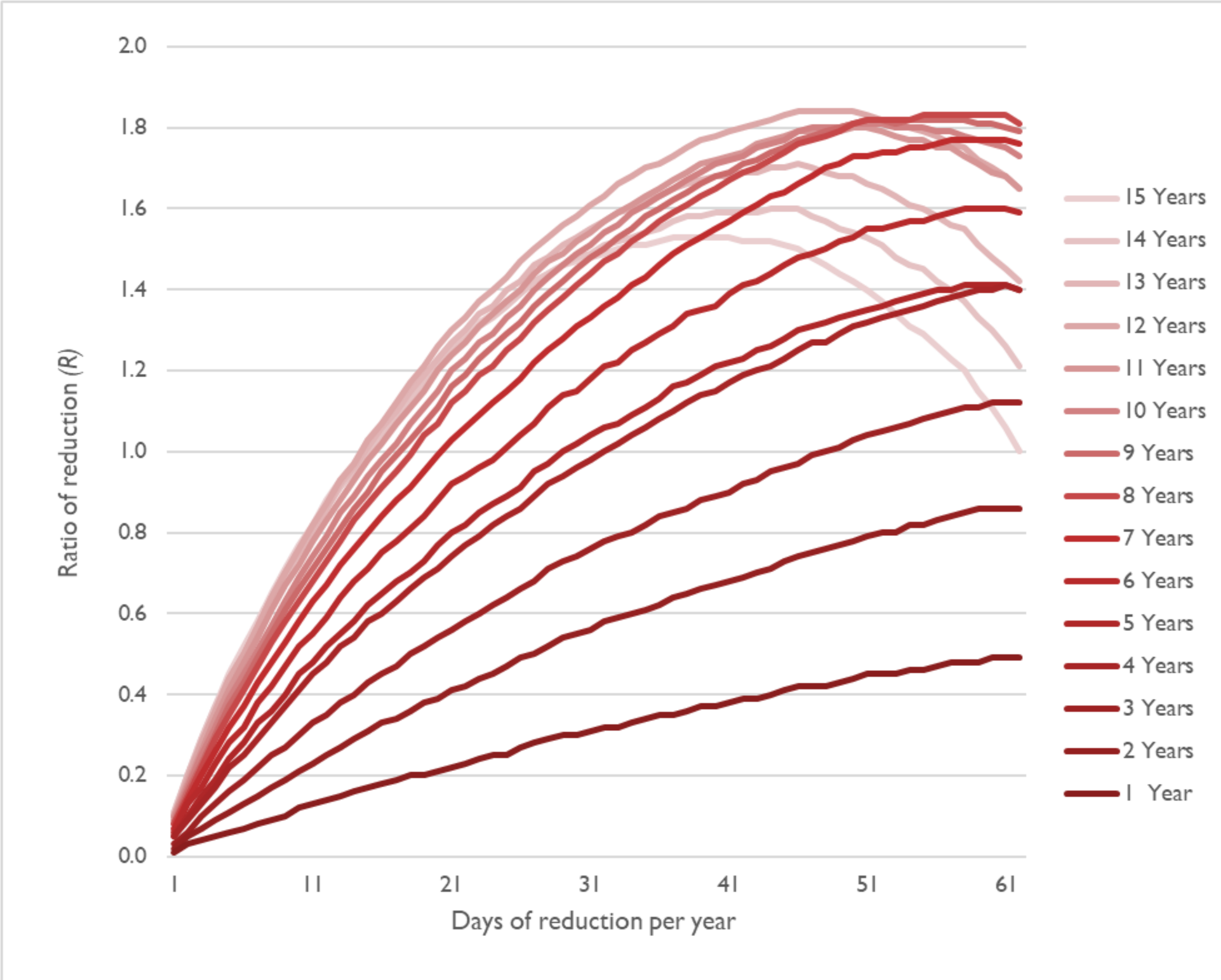
For any duration of a load reduction program, the value of *R* rises with the number of days in which load is reduced, up to at least 35 days. For load reduction programs lasting more than eight years, the value of *R* begins to fall if the number of days reduced exceeds some threshold; at about 55 days for a 9-year program and at about 40 days for a 15-year program.

However, the value of *R* did not vary monotonically with respect to either the number of days or the number of years, and *R* could be more than 1.0, as shown in Figure 69.

For a load reduction program lasting more than two years, reducing load on a large number of days results in $R > 1$, such that the reduction in the load forecast is larger than the reported reduction in the historical load. For a three-year program, *R* peaks at about 1.1 with reductions in 60 days; programs lasting 8 to 12 years have peak *R* above 1.8 for about 50 days of reductions; and a program that reduces load in all 15 years used in the forecast would have a value of *R* over 1.5 for 31 to 46 days of reduction, with *R* falling rapidly for any additional days.

A program that reduces load for all 62 summer days each year for 15 years has an *R* value of exactly 1.0. In effect, such a program would look, for peak-forecasting purposes, like a cleared energy efficiency measure.

Figure 69. Ratio of forecasted load reduction to historical load reduction, various durations

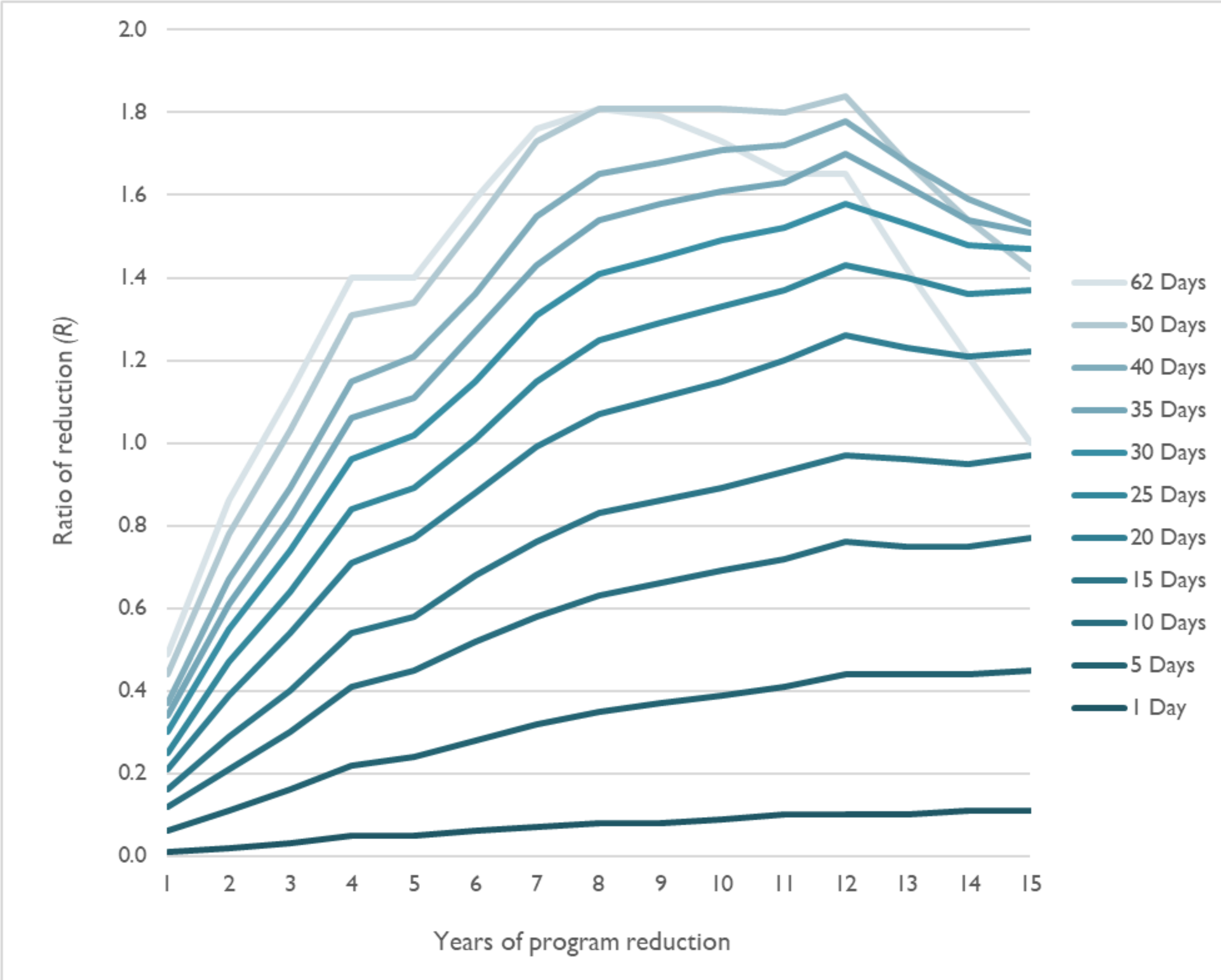


Note: Ratios are shown for 2021 forecasted year.

Figure 70 provides the same data, but with the duration of the reduction in years on the *x* axis and each line representing a number of days of load reduction in each year (essentially swapping the *x* axis and legend in Figure 69). For readability, we present only a subset of days, rather than the full 62.

The horizontal axis in Figure 70 is the number of years that a load reduction has been in place, as of the last year of historical data for the forecast (year $t-2$). See Subappendix A. Ratio of forecast reduction to load reduction for the *R* values from Figure 69 and Figure 70 numerically.

Figure 70. Ratio of forecast reduction to load reduction, various numbers of peak days per year



Applying the results to demand response screening and valuation

The results in Figure 69 and Figure 70 can be used in at least two ways.

First, they can be used to screen potential demand response programs by modifying the values used for uncleared capacity and capacity DRIPE. For example, a new program that would first reduce load in 2020, for the top ten summer days, would be a one-year reduction in the data for the 2021 forecast, which would be used in the 2022 FCA 16 for the summer of 2025. Since we find that a 10-day program has an *R* value of 0.12, a 200 MW load reduction in 2021 would reduce the forecast peak by 24 MW and produce the DRIPE benefits of that size load reduction. Once the program has run for three years (e.g., 2020–2022), it would create a three-year reduction for the 2023 forecast used in 2024 for FCA 18 for the summer of 2027. The program would have an *R* value of 0.30, so the FCA forecast for 2027 would be reduced by 60 MW. Similarly, if the program continues to run for 15 years, the reduction in the forecast used for FCA 30 would be 154 MW.

Second, the results can be used retrospectively, to evaluate the effect of a program that has been operating. In 2019, a Program Administrator might file results for a 100 MW program that it ran in 2014–2018, reducing load on the top 15 days of each summer. From Subappendix A. Ratio of forecast reduction to load reduction, we would use the 15-day row and estimate that the program reduced the load used in the FCA forecasts by 17 MW in 2018 (for which 2014 was the last year of data used in the forecast), 31 MW in 2019, 43 MW in 2020, and 58 MW in 2021. The sum of the avoided capacity and DRIPE from those years would be benefits of the program.

Sensitivity analysis: Other demand response dispatch approaches

This section describes the results of our analysis under a variety of dispatch and implementation sensitivities, including situations in which demand response is dispatched according to weather or in line with day-ahead forecasts. We also examine situations in which the dispatch of demand response misses some peak days, is performed according to some forecast of load distribution, and in which demand response is dispatched for only a single day each year.

Dispatching according to weather, rather than load

Our main analysis assumes that a demand response program identifies the highest-load days and achieves load reduction on those days. We find that the results are essentially identical for a program that concentrates on reducing load on the days with the worst weather (the highest WTHI values), even though those are slightly different from the highest load days.

Dispatching demand response with day-ahead forecasts

We find that the results are also very similar if targeting of the demand response is imperfect, such that the program is activated on some days that are not in the *d* highest days.[398] For example, the program administrator may call an event on a day that looks like it will be one of the top *d* days for the summer, but it may turn out to have an actual load lower than expected. Or, it may turn out that there are more higher-load days that occur later in that summer, after the program administrator has called as many days as is allowed by the tariff or contracts.[399]

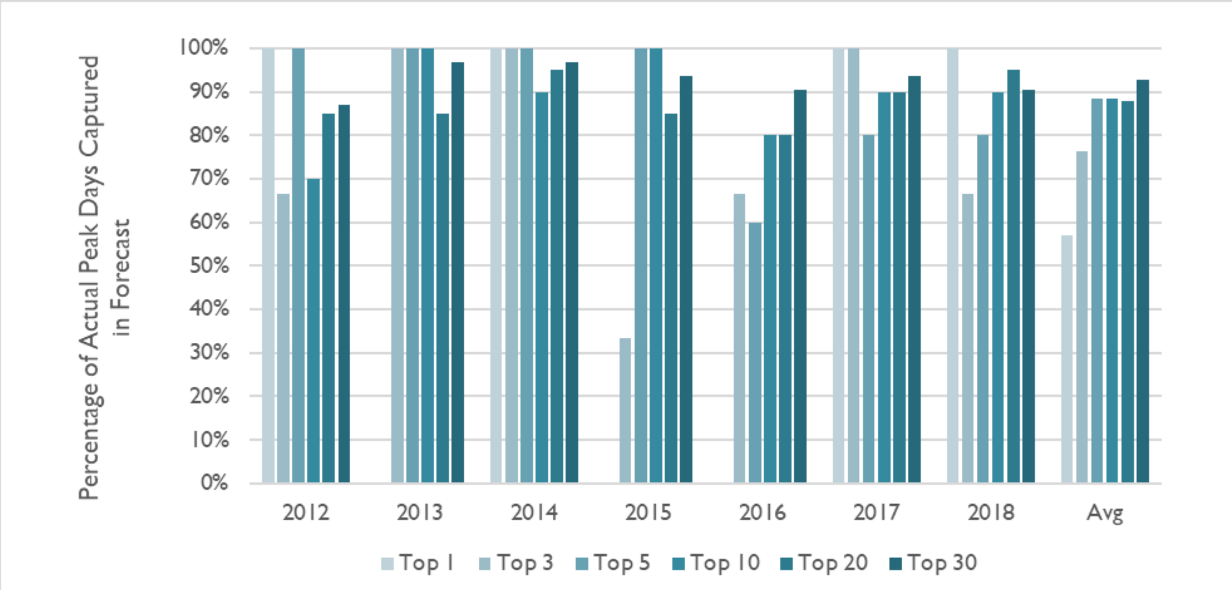
Figure 71 shows the accuracy of demand response program dispatch that is called when the day-ahead peak load is expected to be one of the highest *d* days. These results factor in the optimistic assumption that the program administrator has perfect information about the highest loads for the current summer but not when those highest load days will occur. With this assumption, programs allowing for 5 to 20 days of load reductions would catch 90 percent of the intended control days.

[398] Results are similar, but the curves are less smooth.

[399] The ISO New England day-ahead forecasts are actually quite accurate, correctly flagging the highest *d* days of the summer, if the load of the lowest of those days is known.

Where the day-ahead load would result in activation of a day outside the targeted group, it is almost always close to the intended group. For example, a program targeted at the top 10 days might miss day six, but that unused activation would likely be present on day 11 or 12.

Figure 71. Percentage of highest days flagged by day-ahead load forecast, by year



Dispatching demand response, missing some days

Figure 71 shows the targeting errors if the program administrator somehow knew what the load would be on day d, the lowest load day for which the administrator should activate the program. A more realistic simulation recognizes that the program administrator does not know in early July whether the rest of the summer will be hot or mild, and thus will not know whether a particular day-ahead load forecast is likely to be one the *d* highest days.

Table 179 shows how close the load reductions would be to the perfect-information case with typical substitution of peak days with days just outside the targeted period. For example, Sensitivity Case 4 tests the effect on load reductions of calling an event on the 14th highest day rather than the 9th day of a 10-day per year program, while Sensitivity Case 5 models the effect of calling an event on the 14th highest day rather than the 6th day. Other than Sensitivity Case 1 (an unlikely single-day program calling an event on the second-highest day, rather than the highest-load day), the effect of the imperfect dispatch is within 6 percent of the effect of perfect dispatch, and sometimes the dispatch error actually increases the reduction in forecast load.

Table 179. Ratios of forecast reduction with minor dispatch errors, as a percentage of forecast reduction from perfect dispatch

Sensitivity Case	Event Days	Changes from Optimal Dispatch		Years of Operation			
		Top Days Missed	*Non-Top Days added*	*1*	*5*	*10*	*15*
1	1	#1	#2	67%	92%	92%	81%
2	3	#3	#4	99%	105%	99%	98%
3	5	#5	#7	101%	101%	98%	98%
4	10	#9	#14	99%	97%	98%	98%
5	10	#6	#14	99%	96%	98%	97%
6	20	#14, #17	#25, #30	100%	99%	98%	96%
7	20	#11, #12	#22, #23	98%	97%	97%	96%
8	20	#16, #20	#27, #32	103%	100%	98%	97%
9	31	#18, #24, #27, #30	#34, #37, #40, #43	96%	96%	96%	94%
10	31	#18, #27, #31	#34, #37, #40	98%	97%	97%	95%

Table 180 shows the results for poorly targeted dispatch of a load reduction program in the top 30 days of the summer, either 10 events per year on every third day (starting with day 1 or day 2) or 15 events per year on every second day (either the even-numbered days or the odd-numbered). These dispatch choices represent nearly the worst cases for 10 or 15 annual events, yet they still produce 62 percent to 92 percent of the forecast reduction due to load reductions perfectly targeted to the 10 or 15 days with highest loads.

Table 180. Ratios of forecast reduction with even more imperfect dispatch, as a percentage of forecasted reduction from perfect dispatch

Event Days	Dispatch Days, Ranked by Load	Years of Operation			
		1	*5*	*10*	*15*
10	Every 3rd day: 1, 4, 7, 10, 13, 16, 19, 22, 25, 28	85%	78%	75%	68%
10	Every 3rd day: 2, 5, 8, 11, 14, 17, 20, 23, 26, 29	73%	72%	71%	62%
15	Odd days: 1,3, 5, 7, 9, 11,13,15,17,19,21, 23,25, 27, 29	92%	84%	82%	76%
15	Even days: 2, 4, 6, 8, 10,12,14, 16, 18, 20, 22, 24, 26, 28, 30	84%	78%	76%	68%

Dispatching demand response with forecast load distribution

To examine dispatch errors more systematically, we tested a case in which the program was activated and load was curtailed when the day-ahead forecast was within *k*% of ISO New England's forecast of the summer peak, where *k* is the percentage of peak that, on average over the historical data, was exceeded for *d* days per year.

This is a simplified example of a typical demand response program (such as dynamic peak pricing), in which the program administrator tries to foresee peak days and curtail load on those days. In some low-load years, the program will miss some days that later turn out to have been in the top *d* days, while in other years, the program will operate on days that turn out not to be in the top *d* days.

Demand response program administrators are likely to be more sophisticated than the simple algorithm that we used. For example, the program administrator will know how much of the summer remains, how many event days are left for the year, whether the remainder of the summer is forecast to be warmer or cooler than usual, and what a more detailed forecast for the next week or more shows.

Assuming that the program administrator has no information about the loads for the particular year, dispatching with this simple algorithm results in forecast load savings of 80 percent to 100 percent of the perfect-information dispatch, from about four to fifty event days annually. The detailed pattern of differences between the values shown in Subappendix A and Subappedix B may well be due to the different performance of the algorithm in the specific historical years. Overall, a reasonably thoughtful program administrator should be able to achieve about 95 percent of the benefits shown in Subappendix A.

Daily dispatch values

Finally, we estimated the effects of load reductions in just a single day each year, from the highest-load day to the lowest-load day of the summer, and for one to fifteen years of program operation. The specific effect of reductions in any particular day is probably very sensitive to the specific historical pattern of daily loads and weather, so the detailed differences in the daily values (for example, between the 18^{th} and 19^{th} days, or between seven years and eight years) may not be significant. See Appendix C for our estimate of the R value (reduction in the 2021 forecast as a fraction of the annual historical load reductions), for various number of years and various numbers of days per year.

These daily values, if summed up for the top *d* days, produce load reductions lower than those we found for reductions in the top *d* days. This is illustrated in Figure 72, Figure 73, and Figure 74, for programs lasting 1, 5, and 15 years, respectively. In each figure, we plot the sum of the daily contributions to reducing the load forecast (the sum of days) as compared to the reduction from the top days as a group (the optimal dispatch results). The latter is always larger.

Figure 72. Reduction ratio (R) for 1-year program, various numbers of days

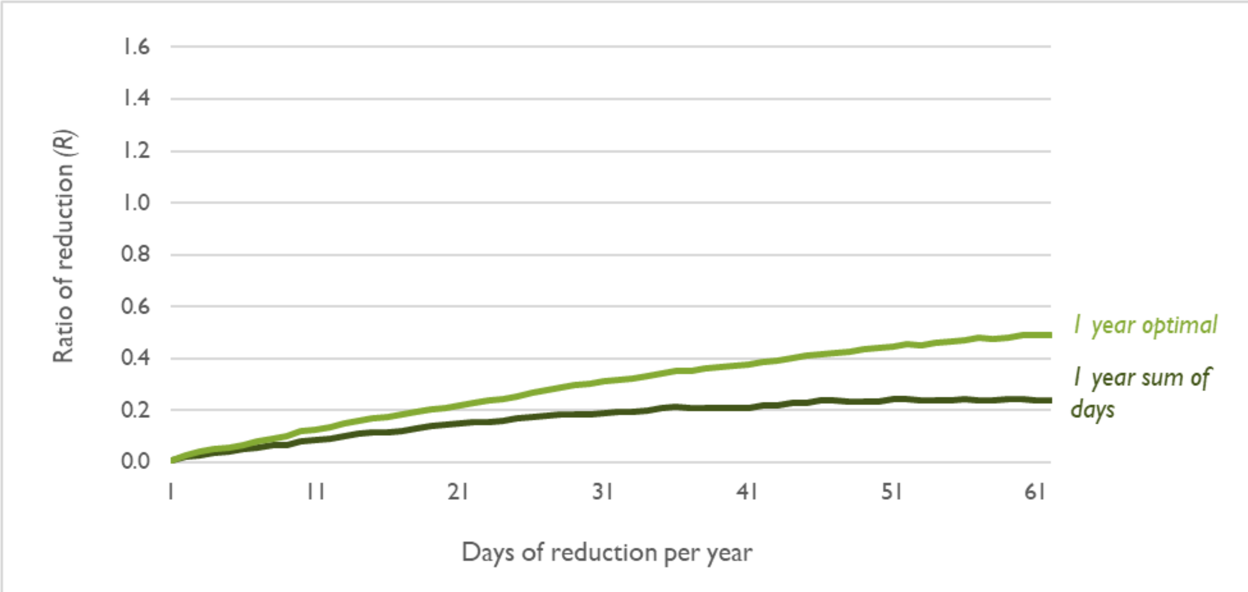


Figure 73. Reduction ratio (R) for 5-year program, various numbers of days

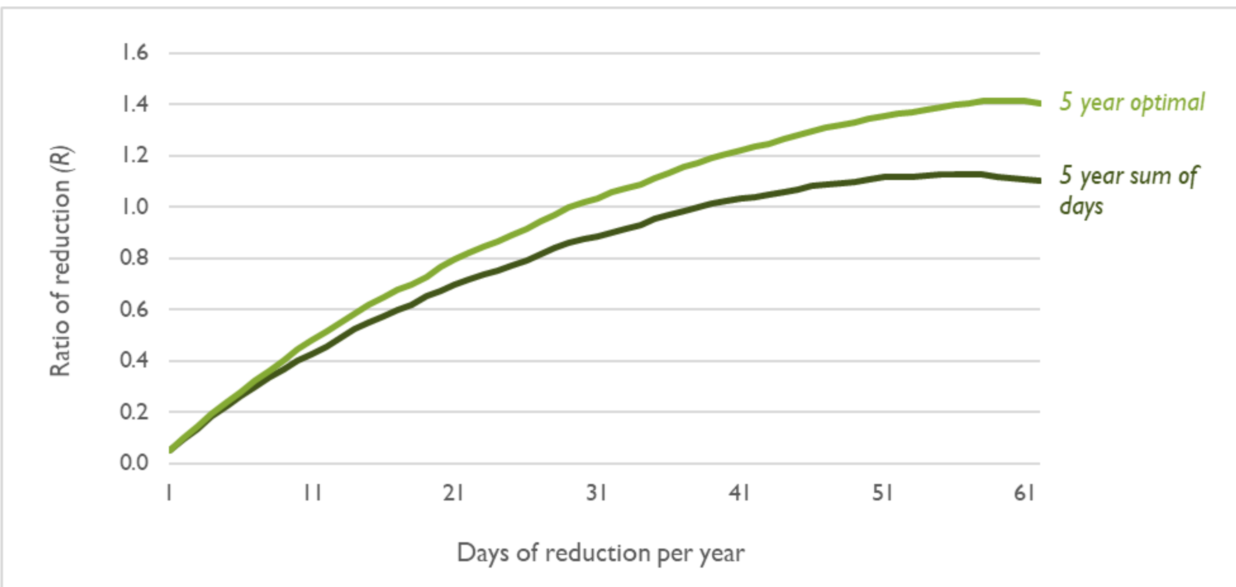
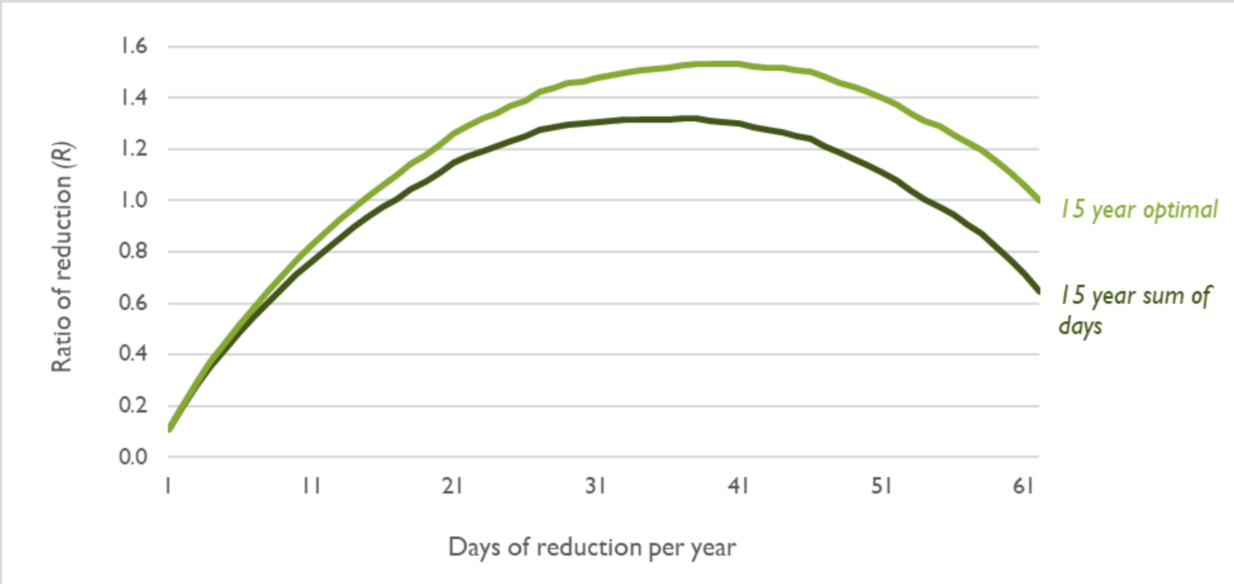


Figure 74. Reduction ratio (R) for 15-year program, various numbers of days



The question then arises, without computing the effects of reductions on all the possible combinations of days (on the order of 10^{18} possibilities), how can the effect of some set of load reductions on uncleared capacity and capacity DRIPE be estimated?

We propose that the load effect (R) for reductions on a set of days *S*, for which the lowest-load day in *S* is the D^{th} highest load day of the summer, be estimated as the average of

1. The sum of the R values for the days in S (from Table 183, Subappendix C), and
2. The R value for D days (from Table 181, Subappendix A), minus the sum of the R values for the days less than D that are not in S (from Table 183, Subappendix C).

For days 1, 4, and 5 of a one-year program (or a program that has only been running for a year), the value would be the average of

The sum of 0.009, 0.013 and 0.005, or 0.027, and

0.06 minus (0.010 + 0.006), or 0.044.

(0.027 + 0.044) ÷ 2 = 0.036.

If greater precision is necessary, or for more complex situations, for example to estimate the effect of different amounts of load reduction on different days over multiple years, we recommend repeating the regressions we describe above for the specific situation.

Subappendix A. Ratio of forecast reduction to load reduction

Table 181 displays the values behind Figure 69 and Figure 70. These values can be applied to uncleared capacity and capacity DRIPE values from AESC 2021 to determine new capacity DRIPE values that are specific to a demand response program.

Table 181. Ratio of forecast reduction to load reduction, by years and days per year

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	0.01	0.02	0.03	0.05	0.05	0.06	0.07	0.08	0.08	0.09	0.10	0.10	0.10	0.11	0.11
2	0.03	0.05	0.06	0.09	0.10	0.13	0.14	0.15	0.16	0.17	0.18	0.19	0.20	0.20	0.20
3	0.04	0.07	0.10	0.13	0.15	0.17	0.20	0.22	0.23	0.25	0.26	0.28	0.28	0.29	0.29
4	0.05	0.09	0.13	0.17	0.19	0.23	0.26	0.29	0.30	0.32	0.34	0.36	0.36	0.37	0.37
5	0.06	0.11	0.16	0.22	0.24	0.28	0.32	0.35	0.37	0.39	0.41	0.44	0.44	0.44	0.45
6	0.07	0.13	0.19	0.25	0.28	0.32	0.37	0.41	0.43	0.45	0.48	0.50	0.50	0.50	0.52
7	0.08	0.15	0.22	0.29	0.33	0.38	0.43	0.47	0.49	0.51	0.54	0.57	0.57	0.57	0.58
8	0.09	0.17	0.25	0.33	0.36	0.42	0.48	0.53	0.55	0.57	0.61	0.64	0.64	0.63	0.65
9	0.10	0.19	0.27	0.37	0.40	0.47	0.53	0.58	0.61	0.63	0.67	0.70	0.70	0.69	0.71
10	0.12	0.21	0.30	0.41	0.45	0.52	0.58	0.63	0.66	0.69	0.72	0.76	0.75	0.75	0.77
11	0.13	0.23	0.33	0.45	0.48	0.55	0.63	0.68	0.71	0.74	0.78	0.82	0.81	0.80	0.82
12	0.14	0.25	0.35	0.48	0.52	0.59	0.67	0.73	0.76	0.79	0.83	0.87	0.86	0.86	0.88
13	0.15	0.27	0.38	0.52	0.55	0.64	0.72	0.78	0.81	0.85	0.88	0.93	0.92	0.91	0.93
14	0.16	0.29	0.40	0.54	0.58	0.68	0.76	0.83	0.86	0.89	0.93	0.97	0.96	0.95	0.97
15	0.17	0.31	0.43	0.58	0.62	0.71	0.80	0.87	0.90	0.94	0.98	1.03	1.01	1.00	1.02
16	0.18	0.33	0.45	0.60	0.65	0.75	0.84	0.91	0.95	0.98	1.02	1.07	1.06	1.04	1.06
17	0.19	0.34	0.47	0.63	0.68	0.78	0.88	0.95	0.99	1.02	1.07	1.12	1.10	1.08	1.10
18	0.20	0.36	0.50	0.66	0.70	0.81	0.91	0.99	1.03	1.07	1.11	1.17	1.15	1.13	1.14
19	0.20	0.38	0.52	0.69	0.73	0.84	0.95	1.04	1.07	1.11	1.15	1.21	1.19	1.17	1.18
20	0.21	0.39	0.54	0.71	0.77	0.88	0.99	1.07	1.11	1.15	1.20	1.26	1.23	1.21	1.22
21	0.22	0.41	0.56	0.74	0.80	0.92	1.03	1.12	1.16	1.20	1.24	1.30	1.27	1.25	1.26
22	0.23	0.42	0.58	0.77	0.82	0.94	1.06	1.15	1.19	1.23	1.27	1.33	1.30	1.28	1.29
23	0.24	0.44	0.60	0.79	0.85	0.96	1.09	1.19	1.23	1.27	1.31	1.37	1.34	1.31	1.32
24	0.25	0.45	0.62	0.82	0.87	0.98	1.12	1.21	1.26	1.29	1.34	1.40	1.36	1.33	1.34
25	0.25	0.47	0.64	0.84	0.89	1.01	1.15	1.25	1.29	1.33	1.37	1.43	1.40	1.36	1.37
26	0.27	0.49	0.66	0.86	0.91	1.04	1.18	1.28	1.32	1.36	1.40	1.47	1.42	1.39	1.39
27	0.28	0.50	0.68	0.89	0.95	1.07	1.22	1.32	1.36	1.40	1.44	1.50	1.46	1.42	1.42
28	0.29	0.52	0.71	0.92	0.97	1.11	1.25	1.35	1.39	1.43	1.47	1.53	1.48	1.44	1.44
29	0.30	0.54	0.73	0.94	1.00	1.14	1.28	1.38	1.42	1.46	1.49	1.56	1.51	1.46	1.46
30	0.30	0.55	0.74	0.96	1.02	1.15	1.31	1.41	1.45	1.49	1.52	1.58	1.53	1.48	1.47
31	0.31	0.56	0.76	0.98	1.04	1.18	1.33	1.44	1.48	1.51	1.54	1.61	1.55	1.49	1.48
32	0.32	0.58	0.78	1.00	1.06	1.21	1.36	1.47	1.50	1.54	1.57	1.63	1.57	1.51	1.49
33	0.32	0.59	0.79	1.02	1.07	1.22	1.38	1.49	1.53	1.56	1.59	1.66	1.59	1.52	1.50
34	0.33	0.60	0.80	1.04	1.09	1.25	1.41	1.52	1.55	1.59	1.61	1.68	1.60	1.53	1.51
35	0.34	0.61	0.82	1.06	1.11	1.27	1.43	1.54	1.58	1.61	1.63	1.70	1.62	1.54	1.51
36	0.35	0.62	0.84	1.08	1.13	1.29	1.46	1.57	1.60	1.63	1.65	1.71	1.63	1.55	1.52
37	0.35	0.64	0.85	1.10	1.16	1.31	1.49	1.59	1.62	1.65	1.67	1.73	1.65	1.57	1.53
38	0.36	0.65	0.86	1.12	1.17	1.34	1.51	1.61	1.64	1.67	1.69	1.75	1.66	1.58	1.53
39	0.37	0.66	0.88	1.14	1.19	1.35	1.53	1.63	1.66	1.69	1.71	1.77	1.67	1.58	1.53
40	0.37	0.67	0.89	1.15	1.21	1.36	1.55	1.65	1.68	1.71	1.72	1.78	1.68	1.59	1.53
41	0.38	0.68	0.90	1.17	1.22	1.39	1.57	1.67	1.69	1.72	1.73	1.79	1.68	1.59	1.53
42	0.39	0.69	0.92	1.19	1.23	1.41	1.59	1.69	1.71	1.73	1.74	1.80	1.69	1.59	1.52

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
43	0.39	0.70	0.93	1.20	1.25	1.42	1.61	1.70	1.72	1.75	1.76	1.81	1.69	1.59	1.52
44	0.40	0.71	0.95	1.21	1.26	1.44	1.63	1.72	1.74	1.76	1.77	1.82	1.70	1.60	1.52
45	0.41	0.73	0.96	1.23	1.28	1.46	1.64	1.74	1.75	1.77	1.78	1.83	1.70	1.60	1.51
46	0.42	0.74	0.97	1.25	1.30	1.48	1.66	1.76	1.77	1.79	1.79	1.84	1.71	1.60	1.50
47	0.42	0.75	0.99	1.27	1.31	1.49	1.68	1.77	1.78	1.80	1.79	1.84	1.70	1.58	1.48
48	0.42	0.76	1.00	1.27	1.32	1.50	1.70	1.78	1.79	1.80	1.79	1.84	1.69	1.57	1.46
49	0.43	0.77	1.01	1.29	1.33	1.52	1.71	1.79	1.80	1.80	1.79	1.84	1.68	1.55	1.44
50	0.44	0.78	1.03	1.31	1.34	1.53	1.73	1.81	1.81	1.81	1.80	1.84	1.68	1.54	1.42
51	0.45	0.79	1.04	1.32	1.35	1.55	1.73	1.82	1.82	1.81	1.80	1.83	1.66	1.53	1.40
52	0.45	0.80	1.05	1.33	1.36	1.55	1.74	1.82	1.82	1.81	1.79	1.82	1.65	1.51	1.37
53	0.45	0.80	1.06	1.34	1.37	1.56	1.74	1.82	1.81	1.80	1.78	1.81	1.63	1.48	1.34
54	0.46	0.82	1.07	1.35	1.38	1.57	1.75	1.82	1.82	1.80	1.77	1.80	1.61	1.46	1.31
55	0.46	0.82	1.08	1.36	1.39	1.57	1.75	1.83	1.82	1.80	1.77	1.79	1.60	1.45	1.29
56	0.47	0.83	1.09	1.37	1.40	1.58	1.76	1.83	1.82	1.79	1.75	1.78	1.58	1.42	1.26
57	0.48	0.84	1.10	1.38	1.40	1.59	1.77	1.83	1.82	1.79	1.75	1.76	1.56	1.40	1.23
58	0.48	0.85	1.11	1.39	1.41	1.60	1.77	1.83	1.82	1.78	1.73	1.75	1.55	1.37	1.20
59	0.48	0.86	1.11	1.40	1.41	1.60	1.77	1.83	1.81	1.77	1.71	1.72	1.51	1.33	1.15
60	0.49	0.86	1.12	1.40	1.41	1.60	1.77	1.83	1.81	1.76	1.69	1.70	1.48	1.30	1.11
61	0.49	0.86	1.12	1.41	1.41	1.60	1.77	1.83	1.80	1.75	1.68	1.68	1.45	1.26	1.06
62	0.49	0.86	1.12	1.40	1.40	1.59	1.76	1.81	1.79	1.73	1.65	1.65	1.42	1.21	1.00

Subappendix B. Ratio of forecast reduction to load reduction, with forecast load distribution

Table 182 displays a modified version of the values in Subappendix A, assuming imperfect dispatch. See the main body of Appendix K, subsection "Dispatching demand response with forecast load distribution" for more information.

Table 182. Ratio of forecast reduction to load reduction, imperfect dispatch

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
2	0.02	0.02	0.02	0.05	0.06	0.07	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.12
3	0.03	0.06	0.08	0.11	0.13	0.15	0.17	0.17	0.17	0.19	0.20	0.21	0.21	0.21	0.21
4	0.04	0.09	0.13	0.17	0.19	0.21	0.25	0.26	0.26	0.27	0.28	0.30	0.30	0.30	0.30
5	0.05	0.11	0.15	0.20	0.22	0.25	0.29	0.30	0.31	0.33	0.34	0.36	0.36	0.36	0.36
6	0.06	0.13	0.17	0.23	0.25	0.29	0.34	0.36	0.37	0.39	0.40	0.42	0.42	0.42	0.42
7	0.07	0.14	0.20	0.27	0.29	0.33	0.38	0.40	0.41	0.44	0.45	0.47	0.47	0.46	0.46
8	0.08	0.16	0.23	0.30	0.32	0.37	0.42	0.45	0.46	0.48	0.50	0.52	0.52	0.51	0.51
9	0.09	0.18	0.25	0.32	0.35	0.40	0.46	0.49	0.50	0.52	0.54	0.57	0.56	0.55	0.55
10	0.10	0.20	0.27	0.35	0.39	0.44	0.51	0.54	0.55	0.58	0.60	0.62	0.62	0.61	0.60
11	0.12	0.22	0.29	0.38	0.42	0.49	0.56	0.59	0.60	0.63	0.65	0.68	0.68	0.66	0.66
12	0.12	0.23	0.31	0.41	0.45	0.53	0.60	0.64	0.65	0.68	0.70	0.73	0.73	0.71	0.71
13	0.13	0.24	0.32	0.44	0.47	0.55	0.64	0.67	0.69	0.71	0.74	0.77	0.77	0.75	0.75
14	0.14	0.25	0.34	0.47	0.51	0.60	0.68	0.71	0.73	0.76	0.79	0.82	0.82	0.80	0.80
15	0.15	0.29	0.38	0.52	0.57	0.66	0.75	0.79	0.82	0.85	0.88	0.91	0.91	0.88	0.88
16	0.15	0.30	0.40	0.55	0.59	0.69	0.78	0.83	0.85	0.88	0.92	0.96	0.94	0.92	0.91
17	0.17	0.32	0.43	0.58	0.62	0.73	0.82	0.88	0.90	0.94	0.98	1.02	1.00	0.98	0.97
18	0.17	0.34	0.45	0.60	0.64	0.75	0.85	0.92	0.94	0.98	1.02	1.06	1.04	1.00	0.99
19	0.18	0.35	0.46	0.62	0.67	0.78	0.88	0.95	0.98	1.01	1.05	1.09	1.07	1.03	1.02
20	0.19	0.37	0.48	0.64	0.69	0.80	0.91	0.98	1.01	1.05	1.09	1.14	1.11	1.06	1.06
21	0.19	0.38	0.49	0.66	0.71	0.82	0.93	1.00	1.03	1.07	1.10	1.15	1.13	1.08	1.07
22	0.20	0.39	0.50	0.68	0.73	0.84	0.96	1.03	1.06	1.10	1.13	1.19	1.16	1.10	1.09
23	0.21	0.41	0.54	0.71	0.76	0.88	1.00	1.07	1.11	1.14	1.18	1.24	1.20	1.14	1.13
24	0.22	0.43	0.56	0.74	0.78	0.90	1.02	1.10	1.13	1.17	1.21	1.26	1.23	1.16	1.15
25	0.23	0.44	0.58	0.76	0.81	0.93	1.06	1.14	1.18	1.21	1.25	1.31	1.27	1.21	1.19
26	0.23	0.45	0.58	0.78	0.82	0.95	1.08	1.16	1.20	1.23	1.27	1.33	1.30	1.23	1.22
27	0.24	0.47	0.60	0.80	0.84	0.97	1.10	1.18	1.22	1.26	1.30	1.36	1.33	1.26	1.25
28	0.25	0.48	0.61	0.81	0.86	0.99	1.13	1.21	1.25	1.29	1.32	1.38	1.34	1.27	1.26
29	0.26	0.50	0.63	0.84	0.88	1.02	1.16	1.25	1.29	1.32	1.36	1.42	1.38	1.31	1.29
30	0.26	0.50	0.63	0.85	0.89	1.03	1.17	1.26	1.30	1.34	1.37	1.43	1.39	1.31	1.29
31	0.27	0.52	0.66	0.87	0.92	1.06	1.21	1.29	1.34	1.37	1.40	1.46	1.42	1.33	1.32
32	0.28	0.53	0.68	0.90	0.94	1.08	1.24	1.32	1.36	1.40	1.43	1.49	1.44	1.35	1.33
33	0.29	0.55	0.71	0.93	0.98	1.12	1.28	1.37	1.41	1.44	1.47	1.53	1.48	1.39	1.35
34	0.30	0.56	0.72	0.95	1.00	1.15	1.31	1.39	1.44	1.47	1.49	1.56	1.50	1.41	1.37
35	0.31	0.58	0.74	0.98	1.03	1.18	1.34	1.43	1.47	1.50	1.53	1.58	1.53	1.44	1.40
36	0.33	0.60	0.78	1.01	1.06	1.21	1.37	1.47	1.51	1.54	1.56	1.62	1.56	1.46	1.43
37	0.34	0.62	0.80	1.04	1.09	1.24	1.41	1.50	1.54	1.57	1.59	1.65	1.58	1.48	1.44
38	0.35	0.63	0.82	1.06	1.11	1.27	1.44	1.53	1.57	1.60	1.62	1.68	1.59	1.50	1.44
39	0.35	0.64	0.83	1.09	1.13	1.29	1.46	1.55	1.60	1.63	1.64	1.69	1.60	1.50	1.45
40	0.36	0.66	0.85	1.10	1.15	1.31	1.48	1.58	1.62	1.65	1.66	1.71	1.62	1.52	1.46
41	0.37	0.67	0.87	1.12	1.17	1.33	1.51	1.61	1.64	1.67	1.68	1.73	1.61	1.50	1.43
42	0.37	0.67	0.88	1.13	1.17	1.34	1.52	1.61	1.65	1.67	1.69	1.73	1.60	1.48	1.41
43	0.38	0.68	0.89	1.15	1.19	1.35	1.53	1.63	1.67	1.69	1.70	1.75	1.61	1.50	1.42
44	0.39	0.69	0.90	1.15	1.20	1.37	1.55	1.64	1.68	1.70	1.71	1.75	1.62	1.50	1.41

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
45	0.39	0.70	0.92	1.18	1.21	1.39	1.57	1.67	1.70	1.73	1.73	1.77	1.64	1.52	1.42
46	0.40	0.71	0.93	1.19	1.23	1.40	1.59	1.70	1.73	1.75	1.75	1.79	1.66	1.54	1.44
47	0.40	0.72	0.94	1.20	1.24	1.41	1.60	1.71	1.74	1.76	1.76	1.79	1.65	1.53	1.43
48	0.41	0.73	0.95	1.21	1.24	1.41	1.60	1.71	1.73	1.76	1.75	1.78	1.63	1.50	1.40
49	0.41	0.74	0.96	1.22	1.26	1.43	1.62	1.73	1.75	1.78	1.77	1.80	1.65	1.51	1.40
50	0.42	0.75	0.97	1.23	1.27	1.44	1.64	1.74	1.76	1.79	1.78	1.80	1.64	1.50	1.38
51	0.42	0.76	0.98	1.25	1.28	1.46	1.65	1.76	1.78	1.81	1.79	1.82	1.65	1.51	1.38
52	0.43	0.78	1.01	1.28	1.31	1.49	1.68	1.79	1.81	1.82	1.80	1.82	1.66	1.51	1.38
53	0.45	0.79	1.02	1.30	1.33	1.51	1.70	1.81	1.83	1.85	1.82	1.84	1.67	1.52	1.38
54	0.45	0.80	1.03	1.31	1.34	1.52	1.71	1.82	1.84	1.85	1.83	1.84	1.68	1.52	1.37
55	0.46	0.81	1.05	1.32	1.34	1.52	1.71	1.82	1.83	1.84	1.80	1.82	1.64	1.47	1.32
56	0.46	0.82	1.06	1.33	1.35	1.53	1.73	1.83	1.84	1.84	1.80	1.81	1.63	1.46	1.30
57	0.47	0.83	1.07	1.34	1.36	1.54	1.73	1.83	1.84	1.84	1.79	1.80	1.62	1.44	1.27
58	0.47	0.84	1.08	1.35	1.37	1.56	1.75	1.84	1.85	1.85	1.80	1.81	1.62	1.44	1.26
59	0.47	0.83	1.08	1.35	1.36	1.54	1.73	1.81	1.80	1.76	1.72	1.72	1.53	1.34	1.16
60	0.48	0.85	1.09	1.37	1.37	1.56	1.73	1.81	1.80	1.77	1.72	1.72	1.52	1.34	1.14
61	0.48	0.85	1.10	1.38	1.39	1.57	1.73	1.81	1.79	1.76	1.71	1.71	1.48	1.28	1.08
62	0.49	0.86	1.12	1.39	1.39	1.58	1.75	1.82	1.80	1.76	1.69	1.69	1.45	1.26	1.04

Subappendix C. Impact of individual day load reductions

Table 183 shows our estimate of the R value (reduction in the 2021 forecast as a fraction of the annual historical load reductions), for various number of years and various numbers of days per year. See the main body of Appendix K, subsection “Daily dispatch values” for more information.

Table 183. Effect of individual day load reductions on reduction ratios

Days	Years of Reductions														
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	0.009	0.021	0.032	0.046	0.051	0.063	0.072	0.079	0.082	0.089	0.096	0.102	0.104	0.106	0.108
2	0.010	0.021	0.031	0.040	0.046	0.056	0.064	0.073	0.078	0.081	0.081	0.086	0.086	0.086	0.087
3	0.006	0.016	0.025	0.036	0.040	0.047	0.056	0.062	0.065	0.069	0.074	0.080	0.080	0.080	0.083
4	0.013	0.024	0.035	0.046	0.050	0.056	0.063	0.069	0.070	0.067	0.081	0.083	0.075	0.075	0.077
5	0.005	0.016	0.026	0.036	0.038	0.044	0.050	0.055	0.058	0.060	0.064	0.067	0.066	0.066	0.068
6	0.011	0.014	0.020	0.038	0.041	0.046	0.052	0.050	0.052	0.053	0.057	0.061	0.059	0.058	0.060
7	0.005	0.013	0.022	0.033	0.034	0.040	0.047	0.052	0.054	0.054	0.056	0.060	0.059	0.058	0.059
8	0.007	0.022	0.024	0.035	0.036	0.045	0.052	0.055	0.056	0.059	0.060	0.062	0.062	0.061	0.063
9	0.004	0.013	0.021	0.031	0.034	0.039	0.044	0.049	0.053	0.054	0.055	0.057	0.055	0.054	0.053
10	0.012	0.014	0.021	0.032	0.030	0.038	0.043	0.047	0.048	0.050	0.050	0.052	0.051	0.051	0.053
11	0.006	0.014	0.020	0.027	0.027	0.032	0.038	0.042	0.043	0.046	0.048	0.050	0.048	0.047	0.047
12	0.004	0.013	0.020	0.027	0.029	0.035	0.040	0.045	0.047	0.049	0.050	0.051	0.050	0.048	0.049
13	0.013	0.022	0.027	0.033	0.036	0.041	0.045	0.049	0.049	0.052	0.045	0.048	0.047	0.046	0.045
14	0.009	0.010	0.017	0.023	0.031	0.028	0.033	0.037	0.038	0.038	0.039	0.042	0.039	0.037	0.043
15	0.004	0.013	0.018	0.024	0.027	0.032	0.036	0.039	0.040	0.041	0.044	0.046	0.044	0.042	0.041
16	0.002	0.010	0.016	0.022	0.023	0.029	0.033	0.036	0.037	0.039	0.039	0.041	0.039	0.036	0.036
17	0.004	0.011	0.016	0.021	0.023	0.027	0.031	0.033	0.035	0.036	0.038	0.041	0.038	0.034	0.033
18	0.009	0.012	0.023	0.024	0.023	0.027	0.031	0.036	0.036	0.037	0.037	0.039	0.040	0.038	0.037
19	0.010	0.017	0.023	0.023	0.031	0.026	0.032	0.036	0.037	0.037	0.036	0.038	0.033	0.031	0.030
20	0.006	0.012	0.012	0.018	0.020	0.023	0.029	0.031	0.034	0.036	0.037	0.039	0.037	0.034	0.035
21	0.004	0.011	0.017	0.023	0.025	0.029	0.033	0.036	0.038	0.037	0.037	0.039	0.039	0.035	0.037
22	0.004	0.010	0.014	0.021	0.019	0.022	0.025	0.028	0.027	0.028	0.026	0.027	0.024	0.024	0.026
23	0.001	0.009	0.015	0.020	0.021	0.024	0.027	0.030	0.030	0.029	0.028	0.032	0.028	0.024	0.022
24	0.007	0.012	0.010	0.015	0.014	0.016	0.019	0.022	0.022	0.022	0.028	0.023	0.019	0.016	0.019
25	0.008	0.015	0.018	0.021	0.023	0.024	0.028	0.030	0.027	0.028	0.026	0.027	0.024	0.023	0.021
26	0.006	0.013	0.018	0.016	0.018	0.021	0.026	0.028	0.027	0.026	0.026	0.027	0.023	0.019	0.018
27	0.005	0.012	0.017	0.024	0.025	0.027	0.030	0.032	0.031	0.031	0.031	0.031	0.028	0.027	0.025
28	0.003	0.009	0.021	0.021	0.025	0.024	0.026	0.032	0.025	0.024	0.021	0.021	0.017	0.013	0.009
29	0.001	0.008	0.013	0.017	0.017	0.023	0.026	0.026	0.025	0.025	0.023	0.023	0.022	0.016	0.012
30	0.002	0.009	0.012	0.015	0.015	0.017	0.021	0.021	0.020	0.020	0.018	0.017	0.013	0.008	0.003

Days	Years of Reductions														
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
31	0.002	0.013	0.016	0.014	0.013	0.016	0.019	0.021	0.020	0.020	0.019	0.019	0.014	0.009	0.005
32	0.008	0.007	0.010	0.015	0.015	0.016	0.020	0.021	0.021	0.020	0.017	0.018	0.014	0.010	0.005
33	0.000	0.005	0.007	0.011	0.012	0.015	0.018	0.020	0.020	0.019	0.018	0.018	0.012	0.009	0.005
34	0.006	0.005	0.013	0.018	0.018	0.021	0.024	0.025	0.024	0.023	0.013	0.013	0.008	0.005	-0.001
35	0.009	0.015	0.018	0.022	0.021	0.017	0.019	0.018	0.016	0.016	0.013	0.013	0.008	0.005	0.000
36	0.002	0.006	0.010	0.015	0.015	0.016	0.019	0.018	0.016	0.015	0.013	0.012	0.008	0.004	0.002
37	-0.001	0.006	0.009	0.014	0.015	0.018	0.020	0.018	0.016	0.015	0.014	0.014	0.009	0.007	0.002
38	-0.001	0.005	0.007	0.018	0.018	0.015	0.016	0.016	0.016	0.015	0.013	0.012	0.009	0.005	-0.001
39	0.000	0.005	0.008	0.011	0.010	0.012	0.014	0.012	0.012	0.011	0.010	0.008	0.002	0.000	-0.006
40	-0.001	0.005	0.009	0.012	0.010	0.010	0.013	0.013	0.012	0.010	0.008	0.008	0.002	-0.002	-0.008
41	0.001	0.006	0.009	0.011	0.011	0.014	0.015	0.014	0.012	0.012	0.010	0.008	0.002	-0.002	-0.006
42	0.008	0.005	0.008	0.010	0.008	0.010	0.012	0.010	0.008	0.005	0.003	0.002	-0.004	-0.008	-0.015
43	0.001	0.005	0.006	0.007	0.008	0.012	0.013	0.013	0.010	0.008	0.006	0.004	0.000	-0.003	-0.010
44	0.008	0.013	0.007	0.016	0.011	0.013	0.015	0.012	0.011	0.010	0.007	0.006	0.003	-0.001	-0.008
45	0.001	0.005	0.007	0.009	0.009	0.011	0.012	0.009	0.006	0.003	0.003	-0.001	-0.007	-0.009	-0.016
46	0.007	0.005	0.008	0.011	0.012	0.012	0.015	0.014	0.011	0.009	0.008	0.005	-0.001	-0.006	-0.011
47	0.001	0.005	0.009	0.010	0.009	0.011	0.011	0.008	0.005	0.001	-0.004	-0.007	-0.013	-0.019	-0.026
48	-0.001	0.003	0.004	0.005	0.002	0.004	0.009	0.007	0.005	0.001	-0.002	-0.004	-0.011	-0.018	-0.026
49	-0.002	0.003	0.008	0.011	0.008	0.009	0.008	0.006	0.003	-0.001	-0.005	-0.007	-0.013	-0.018	-0.023
50	0.001	0.004	0.007	0.008	0.007	0.009	0.007	0.005	0.004	-0.001	-0.004	-0.008	-0.012	-0.018	-0.026
51	0.007	0.011	0.014	0.013	0.010	0.012	0.009	0.006	0.004	-0.005	-0.008	-0.011	-0.018	-0.023	-0.031
52	-0.001	0.002	0.003	0.003	0.000	0.001	-0.001	-0.001	-0.004	-0.009	-0.011	-0.013	-0.019	-0.024	-0.029
53	-0.002	0.001	0.002	0.003	0.001	0.001	-0.001	-0.005	-0.008	-0.013	-0.018	-0.021	-0.026	-0.033	-0.041
54	0.000	0.004	0.004	0.005	0.003	0.002	0.000	-0.003	-0.007	-0.010	-0.015	-0.019	-0.024	-0.027	-0.034
55	-0.002	0.002	0.003	0.006	0.003	0.005	0.003	0.003	0.001	-0.005	-0.008	-0.010	-0.016	-0.021	-0.027
56	0.004	0.001	0.003	0.004	0.001	0.000	-0.001	-0.005	-0.007	-0.013	-0.019	-0.023	-0.021	-0.027	-0.034
57	-0.001	0.001	0.003	0.003	0.000	0.000	0.000	-0.003	-0.005	-0.010	-0.013	-0.018	-0.024	-0.030	-0.038
58	-0.002	0.001	0.002	0.003	0.000	-0.001	-0.003	-0.008	-0.010	-0.013	-0.018	-0.021	-0.025	-0.029	-0.036
59	0.004	-0.001	-0.001	-0.001	-0.006	-0.007	-0.009	-0.011	-0.014	-0.021	-0.028	-0.032	-0.039	-0.045	-0.051
60	0.002	0.004	-0.002	-0.001	-0.004	-0.003	-0.004	-0.008	-0.011	-0.017	-0.024	-0.028	-0.035	-0.042	-0.050
61	-0.005	-0.003	0.006	-0.001	-0.005	0.002	-0.007	-0.009	-0.004	-0.018	-0.025	-0.029	-0.038	-0.047	-0.055
62	0.000	-0.001	-0.002	-0.003	-0.009	-0.013	-0.014	-0.018	-0.022	-0.029	-0.037	-0.040	-0.048	-0.058	-0.068

Attachment M: Bill and Rate Impacts of 2022-2023 Plan

The regulated utilities estimated the following bill and rate impacts of the 2022-2023 plan using Synapse Energy Economics' bill and rate impact model. As the model was built for a three-year plan rather than a two-year plan, the regulated utilities entered the 2021 Plan numbers from the August 2021 Notification Letter filed in DE 17-136 in the models and populated the 2022 and 2023 input fields with their respective data from this Plan filing. Through this model, the energy efficiency programs are expected to reduce the revenue requirements of the regulated electric utilities by -0.4% on average, or -$158.8M in total, over the life of the measures installed during the term and across all programs. The revenue requirements of the regulated gas utilities are expected to reduce by -1.0% on average, or -$58.5M in total. Table 1 provides changes in revenue requirements by utility.

This rate and bill impact analysis reflects changes in electric and gas utility rates and bills and omits a number of key impacts. First, the analysis focuses on electric and natural gas system cost savings, while the NH Utilities implement the energy efficiency programs in a fuel-neutral manner, providing additional benefits to customers that consume oil, propane, or other unregulated fuels. Second, the estimates of long-term bill and rate impacts do not reflect the potential costs of compliance with any future federal or state GHG or other environmental requirements, which would increase the cost to ratepayers of energy resources other than energy efficiency. Third, all costs and benefits included in the model are assumed to reconcile annually, which is not reflective of actual practice. Fourth, there are a number of other benefits, including non-energy impacts resulting from the programs, that are not accounted for in the model. These include but are not limited to (depending on the measures installed): improved air quality; improved health and safety; and improved comfort. Fifth, there are no assumptions built into the model to attempt to accommodate any difference in load that would be realized in the "no EE" scenario. The model simply compares the cost of the programs and the projected savings on just the electric or gas system against zero costs. More information on the assumptions and uses of the model can be found in Attachment N of this filing.

Table 1. Long-term Revenue Requirement Changes due to 2022-2023 Plan, by Utility

Utility	**Percent Change**	**Dollar Change** (millions)
Eversource	-0.4%	-$135.7
Liberty Electric	-0.5%	-$16.2
Unitil Electric	-0.1%	-$6.9
Electric Total	**-0.4%**	**-$158.8**
Liberty Gas	-2.0%	-$44.8
Unitil Gas	-0.4%	-$13.7
Gas Total	**-1.0%**	**-$58.5**

The graphs below show long-term bill and rate impacts over the life of the installed measures for each of four customer segments: residential, low-income, small C&I, and large C&I. Bill impacts are shown separately for the following types of customers:

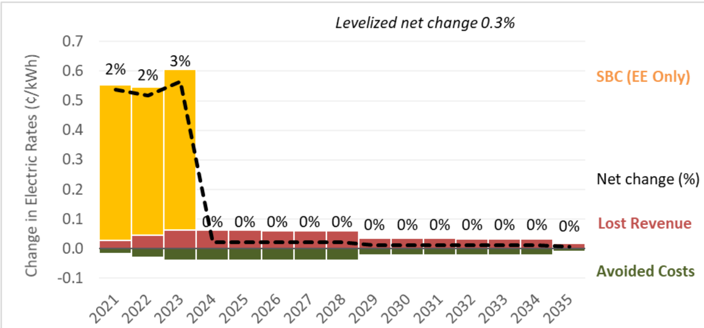
- non-participant—customers who do not participate in any year of the term
- low savings participant—For Electric – an illustrative residential participant (e.g. a customer swapping out their lighting for LEDs) who saves 1% of usage, or C&I participant (e.g. a customer performing a few off-the shelf offerings) who saves 5% of usage during year 1 of the plan; For Gas,

an illustrative low savings residential participant would save 1% of their usage, and a low savings C&I participant would save 5% of their usage.

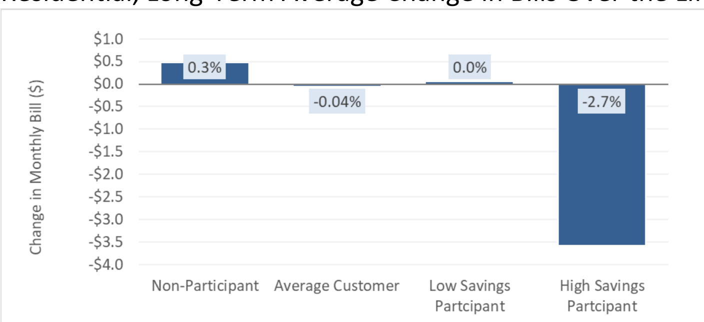
- high savings participant— For Electric – an illustrative residential participant (e.g. a customer performing a comprehensive HPwES project including weatherization and HVAC) who saves 10% of usage, or C&I participant (e.g. a customer performing a comprehensive custom project) who saves 20% of usage during year 1 of the plan; For Gas, an illustrative high savings residential participant would save 7% of their usage, and a high savings C&I participant would save 10% of their usage.
- average customer—a hypothetical blend between non-participants and participants, calculated based on the segment's program savings divided by the segment's total customers.

Eversource Electric

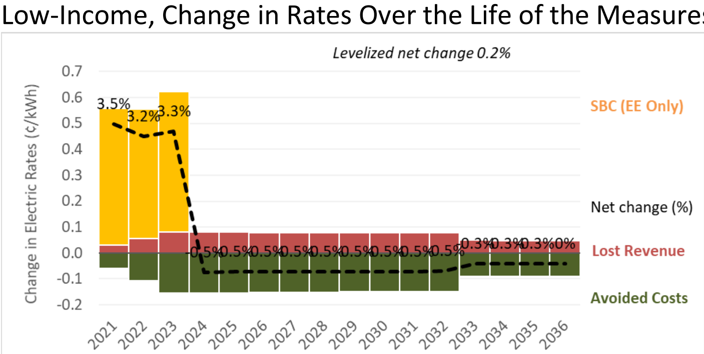
Residential, Change in Rates Over the Life of the Measures



Residential, Long-Term Average Change in Bills Over the Life of the Measures



Low-Income, Change in Rates Over the Life of the Measures



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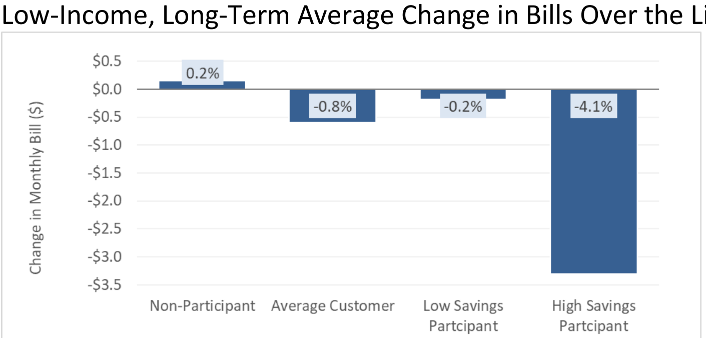
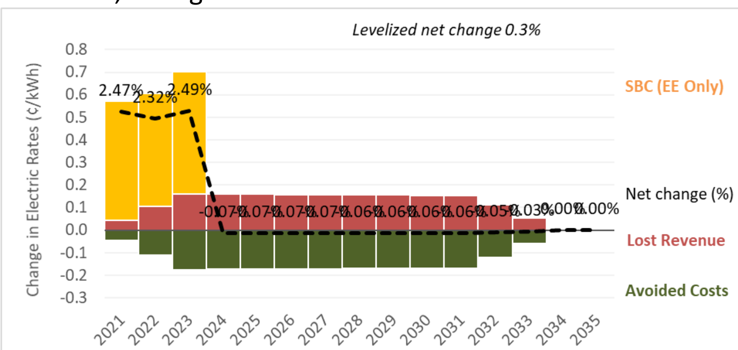


Small C&I, Change in Rates Over the Life of the Measures



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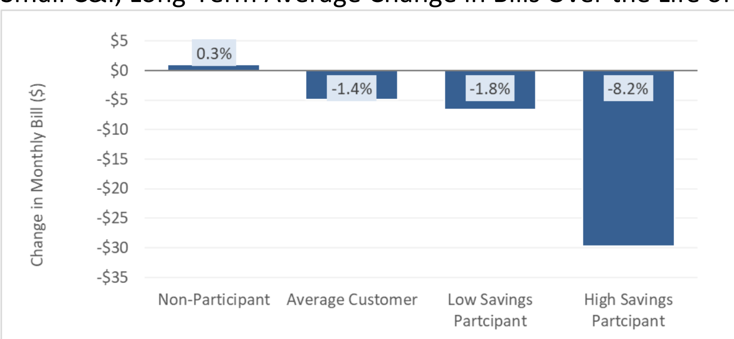

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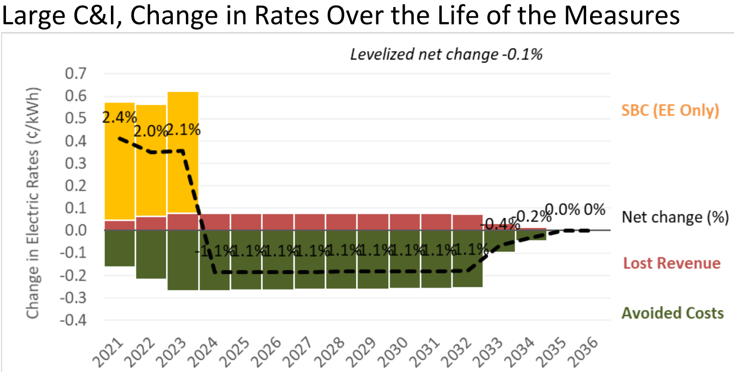

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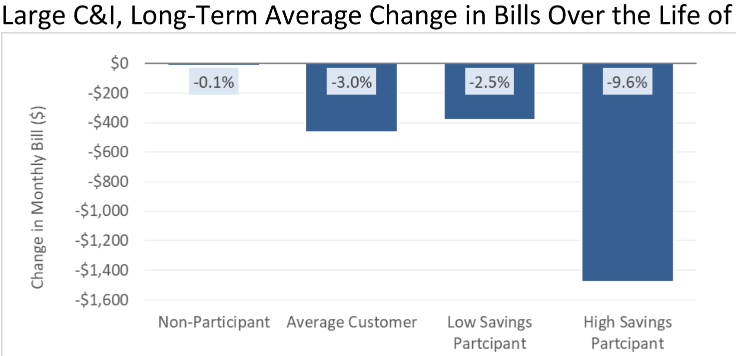
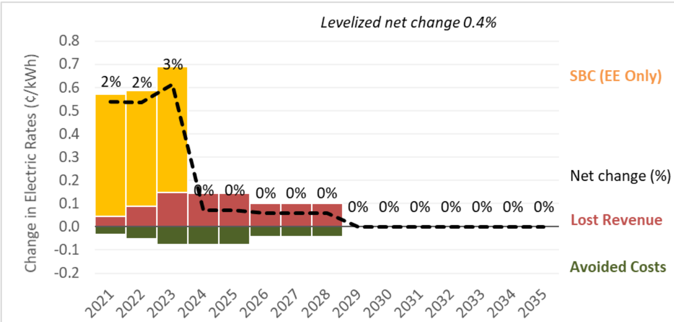
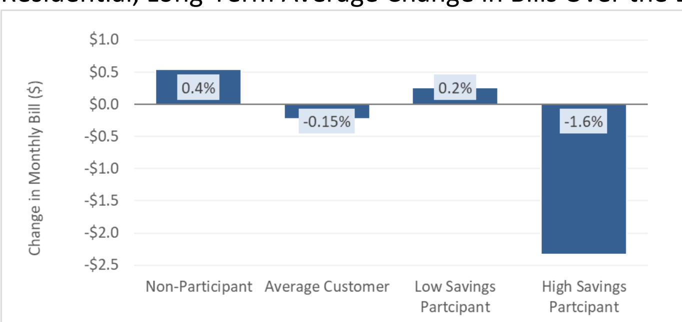


Liberty Electric

Residential, Change in Rates Over the Life of the Measures



Residential, Long-Term Average Change in Bills Over the Life of the Measures



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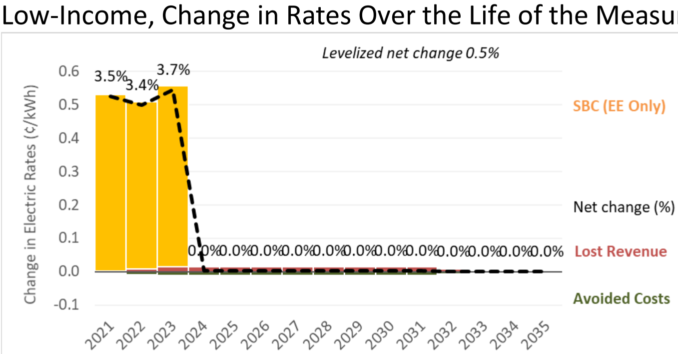
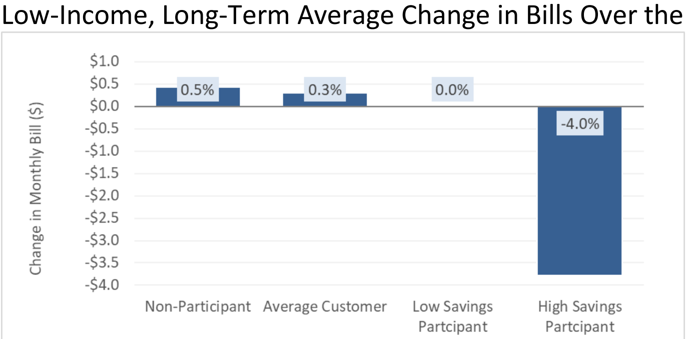


Low-Income, Long-Term Average Change in Bills Over the Life of the Measures



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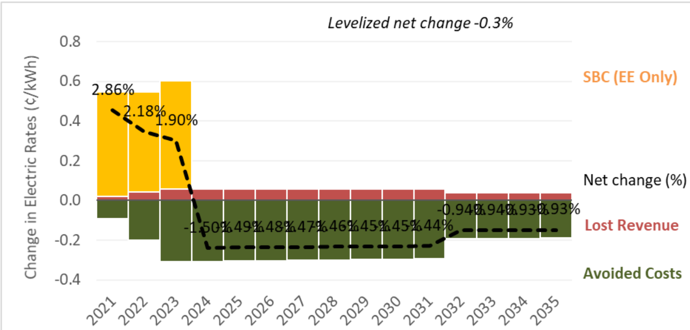

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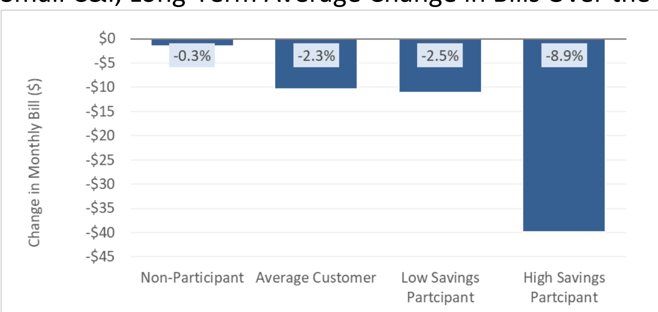

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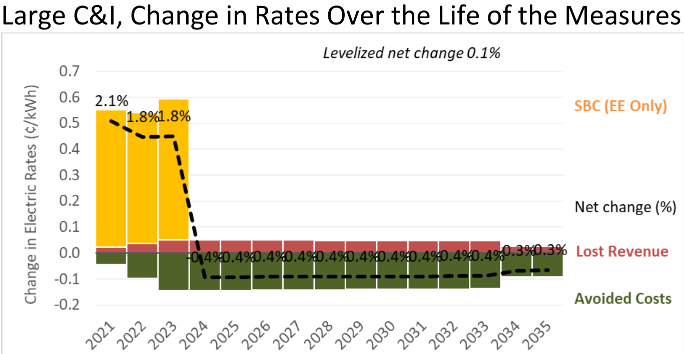

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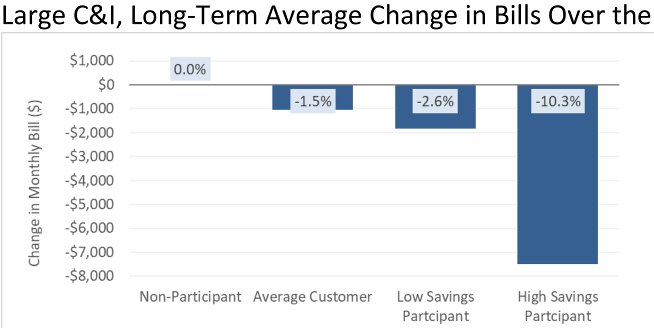
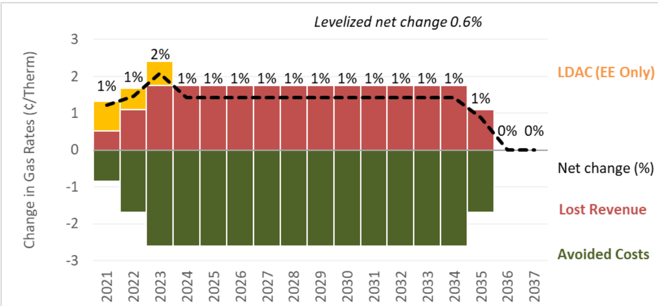
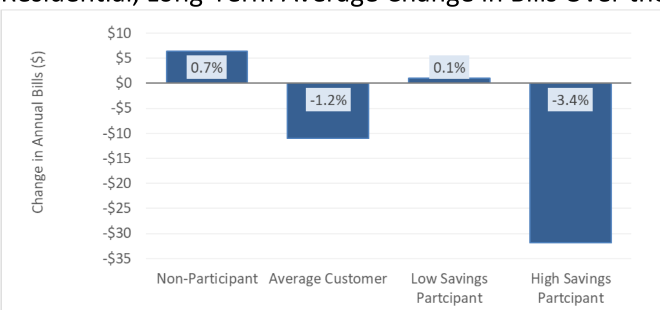


Liberty Gas

Residential, Change in Rates Over the Life of the Measures



Residential, Long-Term Average Change in Bills Over the Life of the Measures



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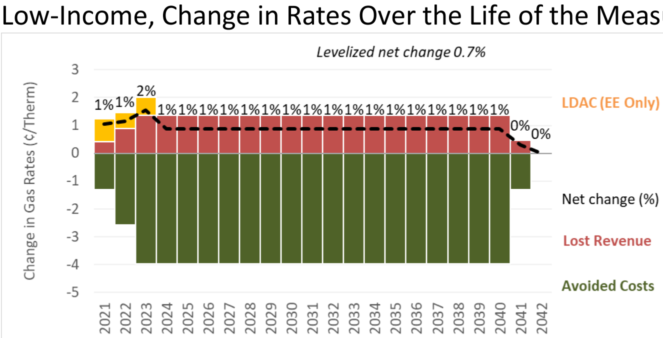

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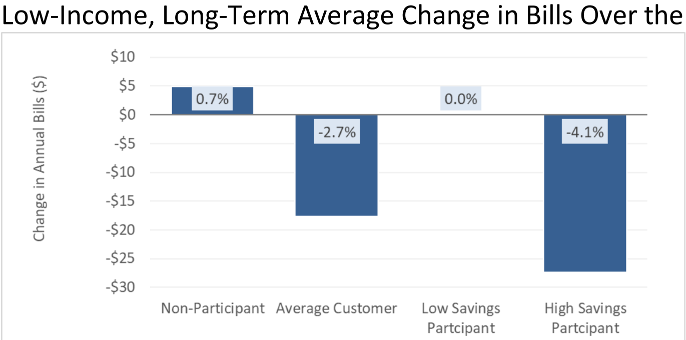

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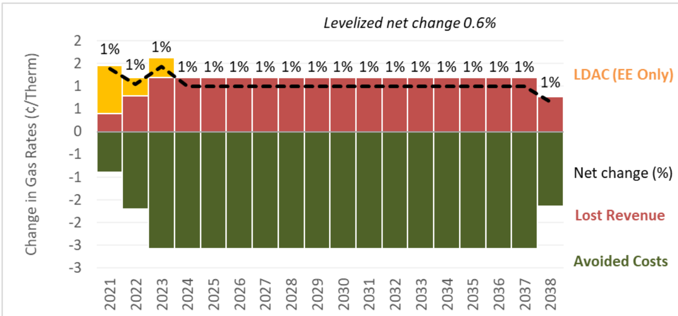

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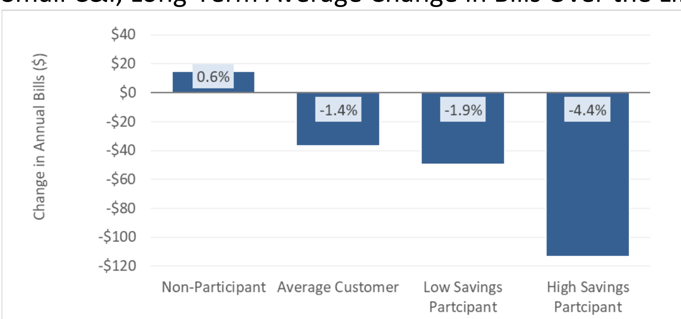

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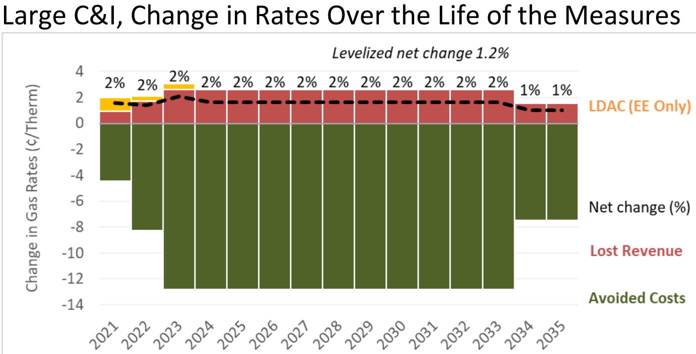

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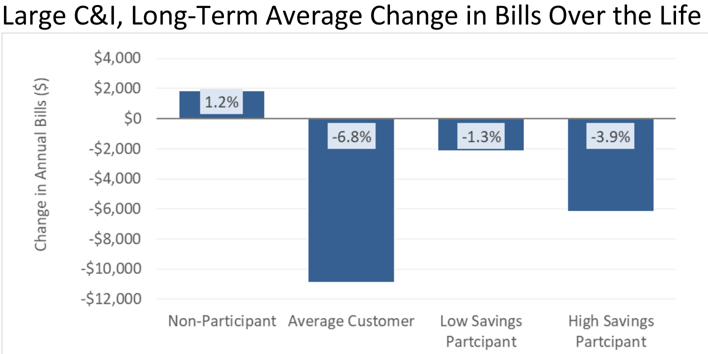
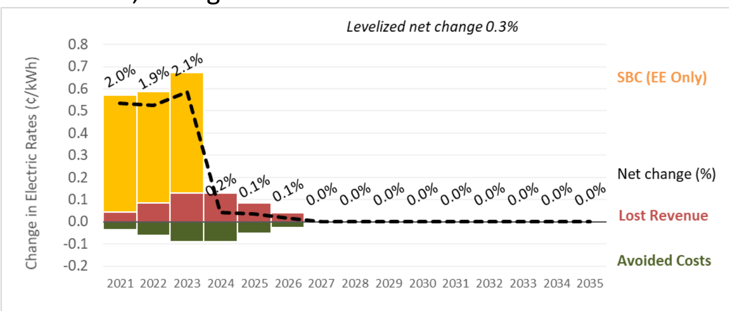


Unitil Energy Systems, Inc.

Residential, Change in Rates Over the Life of the Measures



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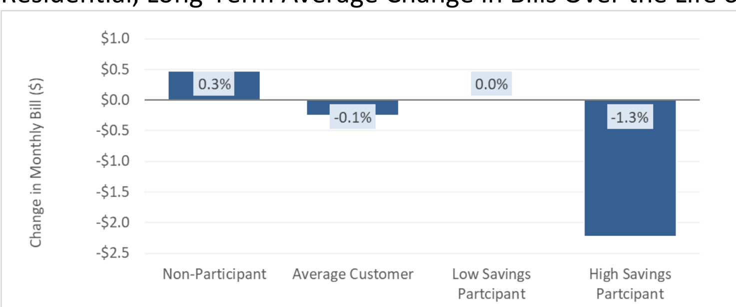

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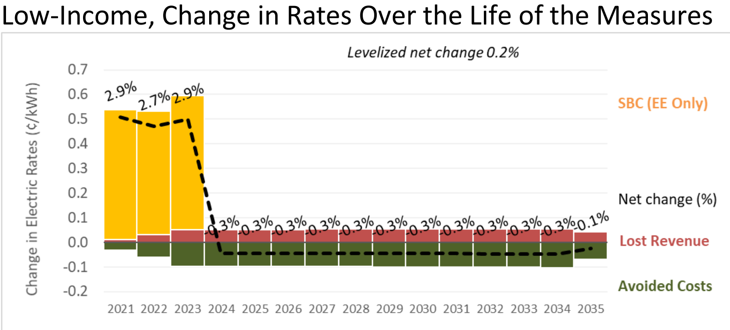

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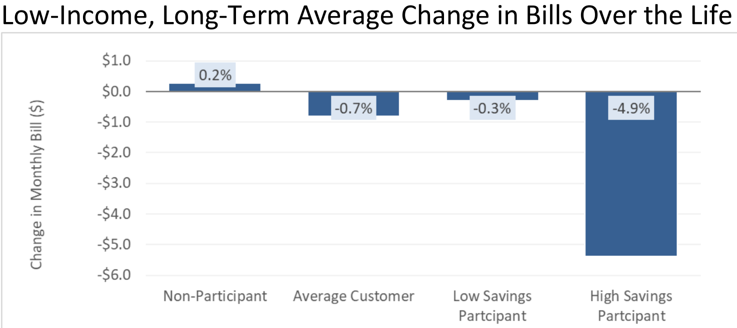

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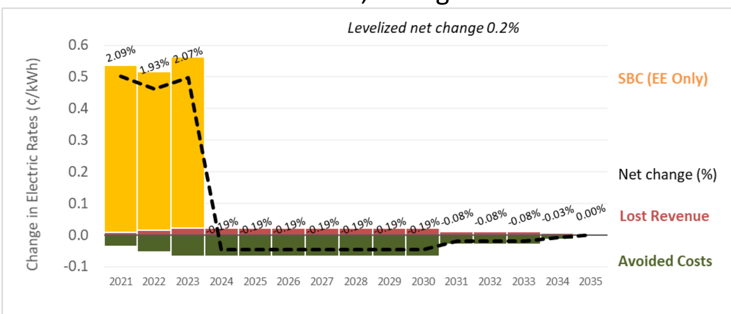

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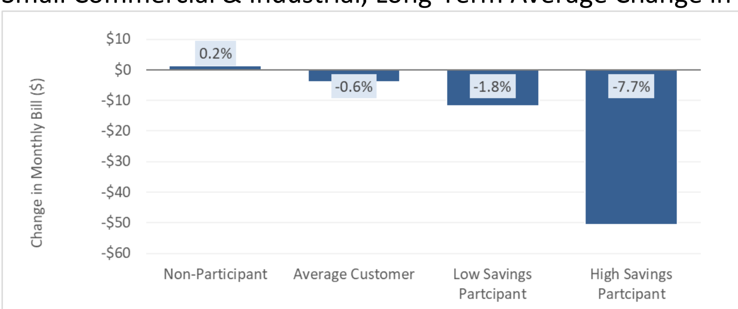

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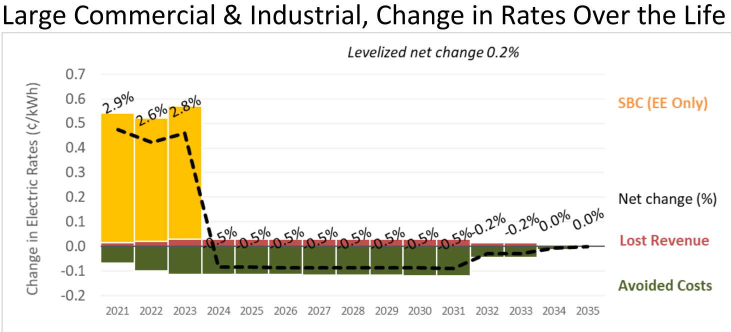

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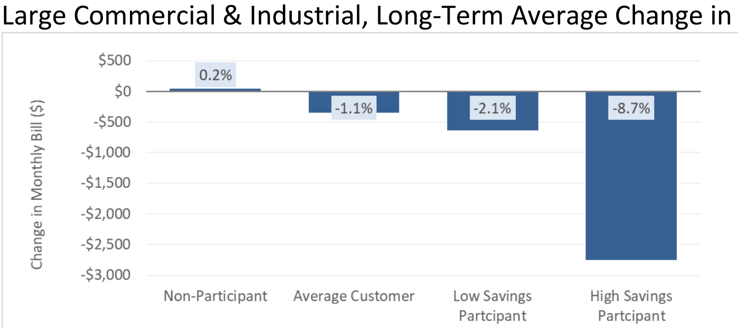
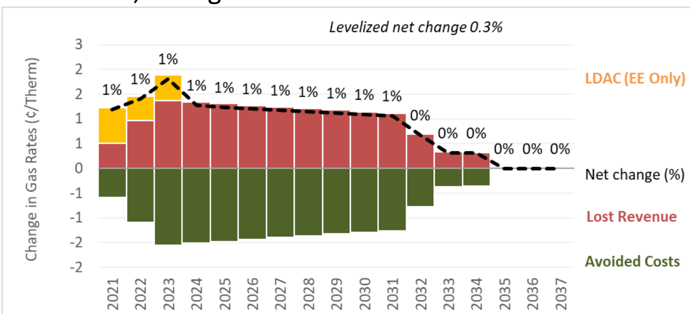
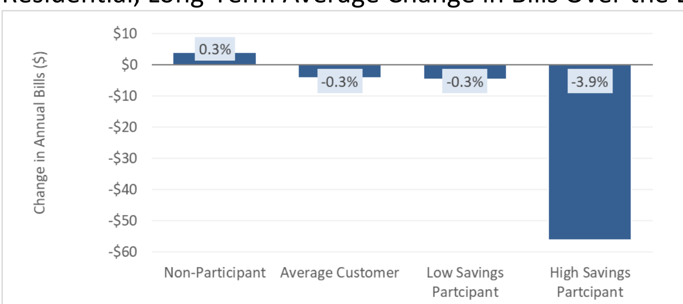


Northern Utilities, Inc.

Residential, Change in Rates Over the Life of the Measures



Residential, Long-Term Average Change in Bills Over the Life of the Measures



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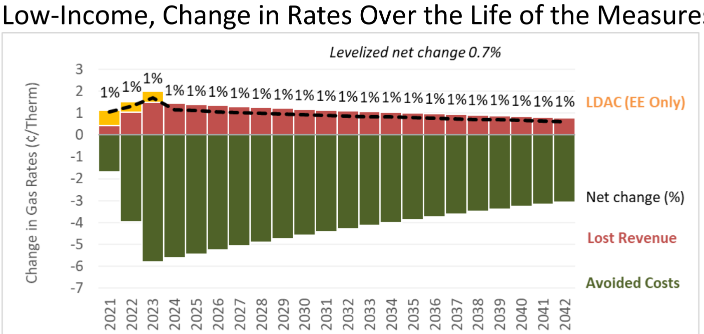
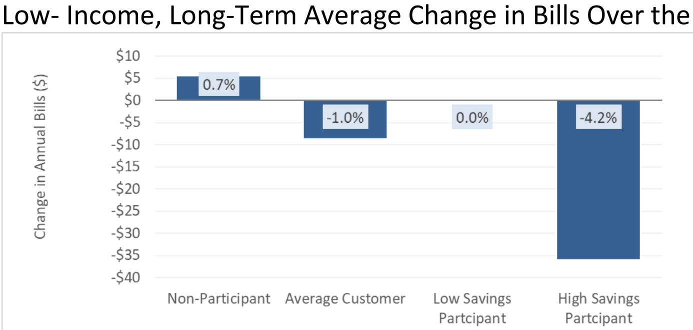


Low- Income, Long-Term Average Change in Bills Over the Life of the Measures



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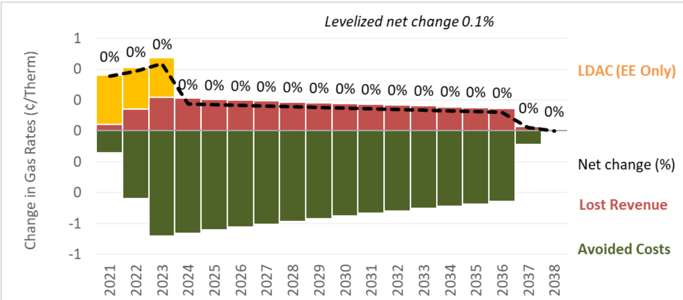

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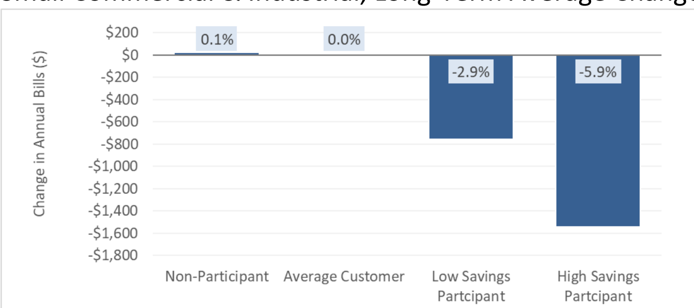

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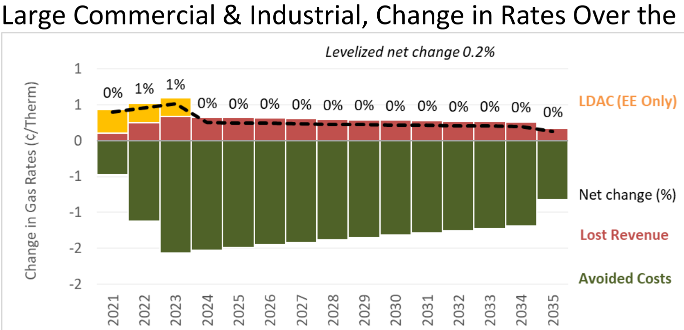

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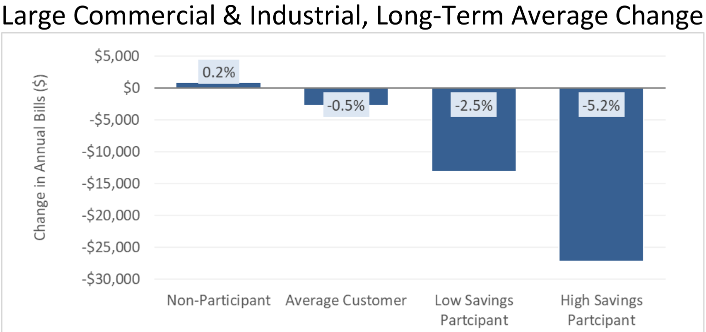


New Hampshire Rate, Bill, and Participation Impact Analysis

A User's Guide to the RBP Models

Prepared for the New Hampshire Evaluation, Measurement, and Verification Working Group

August 5, 2020

AUTHORS

Erin Malone
Kenji Takahashi
Asa Hopkins, PhD
Tim Woolf
Courtney Lane

CONTENTS

1. INTRODUCTION

Rate, bill, and participation (RBP) impacts are key components to assessing the financial impacts and customer equity of energy efficiency programs. The end results of an RBP impact analysis can help inform program priorities, program design, and whether and how to address any equity issues raised by the energy efficiency program. The National Standard Practice Manual (NSPM)—a comprehensive framework for assessing the cost-effectiveness of energy efficiency resources—provides guidance and recommendations on analyzing RBP impacts.[1]

As described in the NSPM, efficiency resources create upward pressure on rates as a result of program cost recovery and lost revenues, as well as downward pressure on rates as a result of avoided utility system costs. In general, the net impact of acquiring efficiency resources is lower average customer bills, despite any increase in rates. Those customers who participate in an efficiency program will typically experience lower bills, while those that do not participate may experience higher rates and consequently higher bills. Therefore, rate impacts of efficiency resources are a matter of customer equity between customers who participate in efficiency programs and those who do not.

A thorough understanding of the implications of efficiency resources requires analysis of three important factors: rate impacts, bill impacts, and participation impacts.

- *Rate impacts* indicate the extent to which rates change for all customers due to utility support for efficiency resources. This includes upward pressure on rates from program cost and lost revenue recovery, as well as downward pressure on rates from avoided utility system costs.
- *Bill impacts* indicate the extent to which customer bills might be reduced for those customers that install efficiency resources and how bills will be impacted for non-participating customers.
- *Participation impacts* indicate the portion of customers that will experience bill changes due to program participation.

Taken together, these three factors indicate the extent to which customers will benefit from efficiency resources and the extent to which efficiency resources may lead to distributional equity concerns. It is

[1] National Efficiency Screening Project (NESP). "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources," Edition 1 Spring 2017, Appendix C, available at https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf.

See also, Synapse Energy Economics, Inc. "New Hampshire Cost-Effectiveness Review," October 14, 2019, Chapter 7, available at: https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2019-10-31_STAFF_NH_COST_EFFECTIVENESS_REVIEW.PDF.

critical to estimate the rate, bill, and participation impacts properly and to present them in terms that are meaningful for considering distributional equity issues.

1.1. Using the Models

We recommend, consistent with the NSPM's guidance, that stakeholders view the combined results of the RBP, and not fixate on each rate, bill, and participation result in isolation. For example, New Hampshire stakeholders should compare (a) the magnitude of bill reductions to program participants, against (b) the magnitude of any rate and therefore bill increases to non-participants, as well as (c) the portion of customers expected to experience bill increases (non-participants) and bill decreases (participants).[2] Such an approach allows stakeholders to appropriately assess the customer equity impacts of efficiency programs.

RBP and Cost-Effectiveness Analyses

New Hampshire stakeholders recently completed a robust process to review and modify the state's cost-effectiveness test for screening efficiency resources.[3] The NSPM provides stakeholders with guidance on how to view cost-effectiveness and RBP results in tandem when determining whether to invest ratepayer funds in efficiency resources. In general, the cost-effectiveness analysis should account for all future avoidable costs and other benefits, while the RBP analysis should assess the customer equity impacts of the efficiency resource. The RBP results should never be included as an input to cost-effectiveness assessments.

There is no bright line that stakeholders can use to determine an appropriate balance across the different analyses. Instead, stakeholders will need to determine this balance through review and discussion, with guidance and final approval by the New Hampshire Public Utilities Commission (Commission or PUC). This determination could include a qualitative comparison between cost-effectiveness and RBP impacts. For example, stakeholders could assess whether any expected long-term rate impacts are warranted, considering cost-effectiveness results, bill reductions, and participation rates.[4]

If stakeholders deem the rate impacts of the utilities' proposed efficiency programs to be unacceptable, then the utilities could modify the proposed programs to better balance cost-effectiveness and

2 NESP, page 123.

3 See, Synapse Energy Economics, Inc., "New Hampshire Cost-Effectiveness Review, Application of the National Standard Practice Manual to New Hampshire," Prepared for the New Hampshire Evaluation, Measurement, and Verification (EM&V) Working Group, October 14, 2019.

4 NESP, 2017, Appendix C.5.

customer equity. To address customer equity issues, the utilities could take any of the following actions:[5]

- Expand efficiency programs and budgets to serve more participants
- Identify customer groups that have not participated as much as other customer groups in recent years and design programs to reach those customers
- Shift priority from programs that have low participation rates to those that have higher participation rates
- Set customer participation targets alongside the energy savings targets when developing efficiency plans
- Require customers to pay a larger portion of the incremental efficiency costs, for example through on-bill financing
- Seek third-party sources of funding to support efficiency programs

Recognizing Other Benefits

An RBP analysis examines efficiency's impact on customers and customer equity. However, there are other factors that could influence a customer's total energy bill that an RBP analysis may not include. This is the case for the RBP analyses developed for New Hampshire utilities.[6] Stakeholders should consider these additional benefits when reviewing efficiency plans, in addition to the cost-effectiveness and RBP results.

First, an RBP analysis typically addresses electric or gas utility rates and bills, based on the rates for the utility implementing the efficiency programs. Utilities in states like New Hampshire implement efficiency programs in a fuel neutral manner, achieving savings from other fuels, including propane, oil, and natural gas if implemented by an electric utility or electricity if implemented by a gas utility. As such, New Hampshire utilities provide additional energy bill savings to customers consuming other fuels. The RBP results do not consider these customer benefits.

Second, the price of carbon is not fully accounted for in New Hampshire electric or gas utility rates. Efficiency programs reduce carbon and other greenhouse gas emissions, which is not accounted for in

[5] NESP, 2017, Appendix C.5.
Synapse Energy Economics, Inc., "New Hampshire Cost-Effectiveness Review, Application of the National Standard Practice Manual to New Hampshire," Prepared for the New Hampshire Evaluation, Measurement, and Verification (EM&V) Working Group, October 14, 2019, Section 7.1.

[6] New Hampshire's utilities are Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty or LU), New Hampshire Electric Cooperative, Inc. (NHEC), Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource or ES), Unitil Energy Systems, Inc. (Unitil or UES), and EnergyNorth Natural Gas, Inc. d/b/a Liberty Utilities and Northern Utilities, Inc.

the New Hampshire RBP analysis. The cost to reduce greenhouse gas emissions the same amount through generation resources other than efficiency would be costlier to ratepayers.

Illustrative Analysis

Compared to the short-term, year-over-year rate impacts utilities historically include in their efficiency plans, the RBP analysis provides a holistic view of the impacts efficiency programs have on customers. The RBP results are illustrative as they provide expected average rate impacts among modeled customer classes. Each customer will experience a different bill impact depending on his or her involvement with the efficiency programs.

The use of illustrative in this report refers to the fact that the RBP analysis is to provide a reasonable estimate of the average rate and bill effects of efficiency programs for an average customer. For example, actual rate impacts could be different from the modeled impacts if rates are not adjusted annually for lost revenues. In addition, the timing of the impact of avoided capacity and transmission and distribution is likely to differ from the assumptions in the model. Due to these factors, the analysis is illustrative and provides approximate impacts for average customers in each customer class. It is not intended to replace or replicate the detailed analyses utilities undertake when calculating rates for efficiency cost recovery through the System Benefit Charge (SBC) for electric utilities or the Local Distribution Adjustment Clause (LDAC) for gas utilities. Utilities should continue to provide those analyses for regulatory review.

1.2. New Hampshire RBP Analysis

In 2018, as part of the New Hampshire utilities' update to the 2019 plan year of their 2018–2020 three-year efficiency plan approved by the Commission, the New Hampshire utilities were required to undertake a detailed bill impact analysis of efficiency programs. The Commission required that the analysis include rate impacts, bill impacts, and participant impacts.[7] In September 2019, the New Hampshire utilities hired Synapse Energy Economics, Inc. (Synapse) to assist the Evaluation, Measurement, and Valuation (EM&V) Working Group in developing Excel-based rate, bill, and participation impact models to assess the long-term impacts of efficiency resources implemented by New Hampshire's electric and gas utilities.

7 "2018-2020 New Hampshire Statewide Energy Efficiency Plan, Settlement Agreement," Docket No. DE 17-136, December 13, 2018, pages 18-19, available at https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2018-12-13_EVERSOURCE_SETTLEMENT_AGREEMENT.PDF.

See Commission Order No. 26,207 in Docket DE 17-136, page 10.

"New Hampshire Statewide Energy Efficiency Plan, 2019 Update," Docket DE 17-136, September 14, 2018, available at https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2018-09-14_EVERSOURCE_UPDATED_EE_PLAN.PDF.

In 2019 and 2020, Synapse worked with the New Hampshire utilities and the EM&V Working Group to create the RBP models. We drafted the Excel models, and the utilities and the EM&V Working Group reviewed the draft models and provided feedback through periodic conference calls.

Synapse created three primary models: an electric rate and bill impact model, a gas rate and bill impact model, and a participation model. This report accompanies those models, providing stakeholders information on our key assumptions and a high-level overview of our methodology. In this report, we focus primarily on the electric and gas rate and bill impact models. We address the participation model in Section 7.

We worked with the New Hampshire utilities to gather the necessary efficiency and rate data, including data related to rate structures, current rates, efficiency plans, avoided costs, and historical program participation. In general, we used 2019 rate data and efficiency data from the utilities' 2020 update to their 2018–2020 three-year energy efficiency plans. We used this data to build the models, provide placeholder assumptions to troubleshoot the models, and provide stakeholders with illustrative results.

On April 1, 2020, the New Hampshire utilities filed the first draft of their 2021–2023 three-year energy efficiency plan. As part of that plan draft, the utilities included the results of the rate and bill impact models. The utilities populated and confirmed all inputs included in the models, including the efficiency assumptions to reflect their proposed 2021–2023 programs.

1.3. Future Modeling

We designed models that the New Hampshire utilities can update and use in future efficiency proceedings. We engaged the EM&V Working Group on model functionality and design elements to ensure the models' longevity.

- *Utility-specific.* The models support separate analyses by each New Hampshire utility using utility-specific data. We streamlined the models to make them easy for the utilities to populate for different efficiency scenarios and rate classes.
- *Well-documented*. Throughout the workbooks, we include notes on model functionality, definition of inputs, source information where applicable, and notes on key assumptions. For example, on the "Overview" tab, we explain the purpose of each tab within the model and note key model assumptions used throughout the model. For each input on the "R&B Inputs" tab, we provide a definition and explanation of how the inputs are used in the model.
- *Instructions.* On the "Instructions" tab, we provide basic model instructions to the utilities for updating the models for future efficiency proceedings, including how to populate the models with utility-specific efficiency and rate data. In this report we provide additional guidance to the utilities and stakeholders on populating and using the models.

2. RATE AND BILL IMPACTS: MODEL OVERVIEW

The New Hampshire rate and bill impact models analyze the long-term impact on rates and bills from a utility's three-year energy efficiency plan. The long-term rate impacts include avoided costs that exert downward pressure on rates, as well as efficiency costs and lost revenue that exert upward pressure on rates. Using the resulting rate impacts, we then provide long-term bill impacts for different types of customers.

2.1. Model Scenarios

The electric and gas rate and bill impact models are dynamic, able to estimate rates and bills for a variety of scenarios.

Electric and gas models. We developed separate models for gas and electric utilities, given differences in avoided costs and rate structures for the two fuel types.

Five utilities. When drafting the models, we analyzed impacts for the three electric utilities and two gas utilities regulated by the New Hampshire PUC.[8] This allowed us to troubleshoot the model inputs and results, as well as confirm all utilities could use the models in future proceedings. Ultimately, we expect each utility will make a utility-specific version of the models and maintain the model inputs to reflect current rates and efficiency data.

Four rate classes. Each model can analyze and provide results for four different rate classes. We attempted to build the models such that the utilities could analyze many of their current rate class structures, including block rates or seasonal rates. We modeled residential, low-income, small commercial, and large commercial rates as a representation of customers impacted by efficiency programs.

Three efficiency scenarios. The models compare three forward-looking scenarios:

- No New Efficiency: a scenario in which no new efficiency resources are implemented in New Hampshire.
- Proposed Efficiency: a scenario that reflects a utility's proposed investment plan in efficiency based on its accompanying benefit-cost screening models.
- Alternative Efficiency: a scenario that reflects an alternative investment strategy for efficiency that can be defined by the utilities and stakeholders.

Traditional utility rate impact analyses typically compare current rates to proposed rates. For efficiency resources, it is useful to review rates and bills in the absence of any new efficiency resources, as a

[8] New Hampshire Electric Cooperative offers energy efficiency services as part of the statewide plan, but is not regulated by the NH PUC in the same way as the investor-owned utilities and is not included in this analysis.

hypothetical case to illustrate the impact of energy efficiency activities relative to a future without new efficiency investments. It is also useful to compare rates and bills of proposed efficiency investments to an alternative proposal, to illustrate the impact different efficiency program portfolios have on customers' rates and bills.

Four customer bill impacts. Customers will experience different bill impacts, depending on their participation in efficiency programs. The models present bill impacts for four different types of customers: non-participants, average customers, high-savings participants, and low-savings participants. See Section 5.3 for more information.

2.2. General Assumptions

We made simplifying assumptions when developing the rate and bill impact models to avoid over-complicating the model and to reduce the level of precision implied in the results. Again, the rate and bill impact models are not meant to replicate a utility's detailed rate modeling, but instead provide an illustrative look at how efficiency programs impact customers on average.

A few primary assumptions used throughout the models are as follows:

- *Forward-looking.* The models are forward-looking only. The models analyze the proposed three-year plan in isolation, including all long-term impacts from those three years of utility investment. The models do not account for costs, or adjustments in revenue from previous efficiency programs, which are not impacted by the forward-going choices regarding efficiency program design or expenditures. To the extent that prior year's efficiency savings are included in the load forecast used by each utility, those savings are included. The participation model is the exception in that it analyzes historical data.

- *Retail-level savings.* We assume all energy savings (in kilowatt-hours (kWh), kilowatts (kW), and therms) are at the retail level, and not at the generation level, wholesale level, or source level. This is consistent with how the utilities typically provide data in their energy efficiency plans and rate cases.

- *Real dollars.* We present all values and results as either a net-present value (NPV) over the study period using a real discount rate or as a levelized value.[9]

[9] At the time of this report the model uses a real discount rate of 1.41 percent to calculate the NPV, which is based on a nominal discount rate of 3.25 percent and an inflation rate of 1.81 percent as included in the utilities' July 1, 2020 draft three-year plan. These values should be updated as needed to match future energy efficiency plans.

3. Rate and Bill Impacts: Methodology

Using the rate and bill inputs (see Section 5), the models calculate pre-efficiency and post-efficiency rates and bills to determine the impact of efficiency programs on customers.

The details of the rate and bill calculations are on the “Yr1,” “Yr2,” “Yr3,” and “YrAll” tabs of the models (referred to in this report as the “Calculations” tabs). The models perform the same calculations for each rate class, for each year, and for the proposed and alternative scenarios, although they adjust for each of these variables in the calculations. Each row in the “Calculations” tabs includes notes indicating the calculations performed for that row. We will not repeat that level of detail in this report. Instead, below, we summarize at a high-level the calculations the models make to estimate rate and bill impacts.

3.1. Rate Impacts

The models separately analyze the impact that efficiency programs have on each rate component. For electric, the rate components are the SBC, distribution, transmission, and generation. For gas, the rate components are distribution, LDAC, and cost of gas.

The models adjust each rate component by the corresponding cost increase or decrease from efficiency programs: avoided costs (decreases rates), lost revenue recovery (increases rates), and efficiency cost recovery (increases rates).[10] Using the electric transmission rate as an example, the models start with the pre-efficiency transmission rate, add lost transmission revenues, and subtract avoided transmission costs to determine the post-efficiency transmission rate. The difference between pre- and post-efficiency transmission rate is the transmission rate impact.

We address lost revenue calculations in more detail in Section 4.1.

Avoided Costs

The utilities enter benefits directly into the rate and bill impact models from their energy efficiency benefit-cost screening models. The benefit-cost screening models calculate lifetime benefits using avoided energy costs and the proposed efficiency savings. The rate and bill impact models convert lifetime benefits into annual benefits using the weighted average measure life for the customer sector. They also convert the benefits to ensure results are in real dollars.

Electric Rate Calculations

The electric rate impacts are determined by subtracting the post-efficiency rate from the pre-efficiency rate. The post-efficiency rates are determined as follows.

[10] The exception to this calculation is distribution lost revenue, as explained in the *Distribution Lost Revenue* section.

Distribution. The post-efficiency distribution rate accounts for distribution avoided costs and lost revenue. The formula is:

$$\frac{Post\text{-}efficiency\ distribution\ revenue\ (\$)}{Post\text{-}efficiency\ sales\ (kWh\ or\ kW)}$$

where:

- Post-efficiency distribution revenue is the pre-efficiency distribution revenue less distribution avoided costs (all in $).
- Post-efficiency sales are the pre-efficiency sales less efficiency savings (all in kWh or kW).
- Pre-efficiency sales include all past savings from prior efficiency programs. It does not account for the impact of the efficiency plan being modeled or any future efficiency plans beyond the plan being modeled.

Transmission. The post-efficiency transmission rate accounts for transmission avoided costs and lost revenue. The formula is:

$$\begin{aligned}&Pre\text{-}efficiency\ transmission\ rate\ (\$/kWh\ or\ \$/kW)\\&+ \text{-}avoided\ transmission\ rate\ (\$/kWh\ or\ \$/kW)\\&+ transmission\ lost\ revenue\ rate\ (\$/kWh\ or\ \$/kW)\end{aligned}$$

where:

- Pre-efficiency transmission rate is the utility's transmission rate for the rate class ($/kWh or $/kW).
- Avoided transmission rate is the avoided transmission costs ($) divided by post-efficiency sales (kWh or kW).
- Transmission lost revenue rate is calculated using the same methodology used to calculate distribution lost revenue rate (see Section 4.1).

Generation. The post-efficiency generation rate accounts for energy Demand Reduction Induced Price Effect (DRIPE), avoided capacity costs, capacity DRIPE, and reliability. The models do not include avoided energy costs in the generation rate impacts, because avoided energy costs impact customers' bills only, not the generation rate. The avoided energy costs are only realized when a customer participates in an efficiency program and reduces their consumption. Therefore, the formula is:

$$\begin{aligned}&Pre\text{-}efficiency\ generation\ rate\ (\$/kWh)\\&+ \text{-}energy\ DRIPE\ rate\ (\$/kWh)\\&+ \text{-}avoided\ capacity\ rate\ (\$/kWh)\\&+ \text{-}capacity\ DRIPE\ rate\ (\$/kWh)\end{aligned}$$

where:

- Pre-efficiency generation rate is the utility's standard offer generation rate for the rate class ($/kWh).
- All avoided cost rates ($/kWh) are the indicated avoided costs ($) divided by post-efficiency sales (kWh).

SBC rate. The post-efficiency SBC rate is simply equal to the SBC rate necessary to support the proposed electric efficiency programs and does not include the distribution or transmission lost revenues. The changes to distribution and transmission rates are calculated separately, as described in the formulas on page 9 above.

Gas Rate Calculations

The gas rate impacts are also determined by subtracting the post-efficiency rate from the pre-efficiency rate. The post-efficiency rates are determined as follows.

Distribution. The post-efficiency distribution rate accounts for the retail margin within avoided gas costs and lost revenue. The retail margin represents the portion of distribution costs that are avoidable based on reductions in natural gas usage from efficiency measures. In their benefit-cost screening models, the New Hampshire gas utilities use avoided gas costs that include an estimate for the retail margin. In the rate and bill models, we assume the retail margin represents about 6 percent of total avoided gas costs, which is the percent the retail margin comprises within the *Avoided Energy Supply Components in New England 2018 Report* (AESC).[11] The formula for the post-efficiency distribution rate is:

$$\frac{Post\text{-}efficiency\ distribution\ revenue\ (\$)}{Post\text{-}efficiency\ sales\ (therms)}$$

where:

- Post-efficiency distribution revenue is the pre-efficiency revenue less the retail margin within avoided gas costs (all in $).
- Post-efficiency sales are the pre-efficiency sales less efficiency savings (all in therms).

LDAC (excluding energy efficiency portion). The post-efficiency LDAC accounts for changes in sales. In the model, this rate does not include energy efficiency cost recovery. In practice, the utilities include efficiency cost recovery within their LDAC rates. Otherwise, efficiency programs do not modify a utility's non-efficiency LDAC revenue. The formula is as follows:

[11] See 2018 AESC Study, pages 43-44 and Appendix C. This can be adjusted in the model to account for future AESC results.

$$\frac{LDAC\ revenue\ (\$)}{Post\text{-}efficiency\ sales\ (therms)}$$

where:

- LDAC revenue is the utility's pre-efficiency LDAC rate without efficiency cost recovery ($/therm) multiplied by the pre-efficiency sales (therms) for the rate class.
- Post-efficiency sales are the pre-efficiency sales less efficiency savings (all in therms).

Energy efficiency portion of LDAC. The efficiency portion of the LDAC is equal to the rate necessary to support the proposed gas efficiency programs. This is the equivalent to the SBC rate for the electric efficiency programs.

Cost of gas. The post-efficiency cost of gas rate accounts for gas DRIPE. The models do not include avoided gas costs in the cost of gas rate impacts, because avoided gas costs impact customers' bills only and not the cost of gas rate. The formula is:

$$\begin{aligned}&Pre\text{-}efficiency\ cost\ of\ gas\ rate\ (\$/therm)\\&+ \text{-}gas\ DRIPE\ rate\ (\$/therm)\end{aligned}$$

where:

- Pre-efficiency cost of gas rate is the utility's cost of gas rate for the rate class.
- Gas DRIPE rate is the gas DRIPE benefit ($) divided by post-efficiency sales (therm).

3.2. Bill Impacts

The models calculate bill impacts for electric and gas utilities and for each customer sector using the same methodology. They compare the bill of a non-participant in the No New Efficiency scenario to the bills for each customer type (non-participant, average customer, high-savings participant, and low-savings participant) using the post-efficiency rates and adjusting the typical customer's consumption to reflect the type of customer modeled.

Using a high-savings participant as an example, the models first determine the customer's post-participation consumption by reducing the typical customer's consumption for the rate class by the savings a high-savings participant is expected to save in a month (for electric utilities) or a year (for gas utilities).[12] For example, if a residential electric customer typically consumes 600 kWh per month, and that customer saves 60 kWh per month after participating in the efficiency programs, then their new consumption is 540 kWh per month.

[12] The utilities determine the participant's savings for each rate class (see *Participant Bill Savings*).

The models then multiply the resulting consumption by the post-efficiency rates from the Proposed or Alternative Efficiency scenario. The resulting bill for the high-savings participant accounts for both the rate impact and the change in consumption from participating in the program.

The models compare the high-savings participant's bill to the bill of a non-participant in the No New Efficiency scenario. The non-participant's bill in the No New Efficiency scenario is the typical customer's consumption for the rate class multiplied by rates that assume no new efficiency programs in the future. The difference between the two bills provides the high-savings participant bill impact.

4. Rate and Bill Impacts: Key Assumptions

In this section, we highlight key modeling assumptions we made when developing the rate and bill impact models for New Hampshire.

4.1. Lost Revenue and Decoupling

The term "lost revenue" refers to the revenue that utilities do not recover from ratepayers because of reduced sales from energy efficiency programs. When regulators take steps to allow utilities to recover lost revenues resulting from efficiency programs through mechanisms such as rate cases, revenue decoupling, lost revenue adders, or other means, it will create upward pressure on rates. If this upward pressure on rates exceeds the expected downward pressure from reduced utility system costs resulting from efficiency programs, then rates will increase, and vice versa.[13]

All New Hampshire utilities recover lost revenues that result from efficiency programs.[14] Liberty Gas has implemented a decoupling mechanism, and Liberty Electric has proposed decoupling in its current rate case.[15] Eversource and Unitil (both gas and electric) collect lost revenue through the energy efficiency components of the electric SBC and gas LDAC rates. For simplicity and consistency, the RBP analysis assumes that rates and bills reflect annual changes in utility costs. In effect, the model assumes annual rate adjustments through a decoupling mechanism. In reality, utilities that are not decoupled would have occasional rate cases, after which point the avoided costs and the expected lost revenues from energy efficiency programs implemented in the previous years would be reflected in rates. Choosing this approach allows the RBP to have the same structure for all utilities (whether decoupled or not) and avoids the need to add assumptions regarding when future rate cases will occur.

We use the term "recovery of lost revenue" throughout the rate and bill impact models and this report to refer to recovery of fixed costs over fewer sales, regardless of how a how utility recovers those costs.

Model Assumptions

In this section, we summarize at a high level our approach to calculating lost revenues. In the sections that follow, we explain in detail our modeling assumptions and calculations for both distribution and transmission (electric utilities only) lost revenue.

[13] NESP, page 114.

[14] See, NH Lost Base Revenue (LBR) Working Group, "New Hampshire Energy Efficiency Calculation of Lost Base Revenue For Measures installed beginning in 2019," Docket No. DE 17-136, August 29, 2018.

[15] See Docket Nos. DG 17-048 and DE 19-064.

Simplified approach. In general, the models use simplified approaches to calculate lost revenue. We use simplified methods because we intend for the rate and bill impact model to provide stakeholders with an approximate estimate of rate and bill impacts, not exact rate impacts.

Comparison to utility approach. We do not recreate the exact formulas used by the New Hampshire utilities to calculate lost revenues. The rate and bill impact models could become outdated if utilities adjust their recovery mechanisms relatively soon.[16] It would over-complicate the models to replicate the utilities' different calculation methods, especially the differences between lost revenue calculated through the SBC or LDAC rates or a decoupling mechanism. For example, decoupling mechanisms often also account for changes in rates that occur for reasons other than efficiency resources. The primary difference between the lost revenues calculated in the utilities' SBC or LDAC rates and the rate and bill impact model is that the utilities account for savings as they are acquired over the course of the installation year. In the rate and bill impact model, we essentially assume all savings are acquired on January 1 of the installation year. The utilities also use an average distribution rate across rate classes, while we use the distribution rate associated with the specific rate class.

Applicable to all recovery mechanisms. The lost revenue calculations we use in the rate and bill impact model are applicable to all New Hampshire utilities, regardless of whether the utility has implemented a decoupling mechanism or collects lost revenue through a rate adjustment mechanism. This approach allows the utilities to use a common rate and bill impact model.

Isolating fixed costs. If a utility only had variable costs, then there would be no lost revenues. The utility would be financially neutral to energy efficiency investments because efficiency savings would reduce costs and revenues by a comparable amount. But utilities have both variable and fixed costs, and a utility needs to recover the fixed costs despite lower sales from efficiency savings. As explained in more detail below, we estimate lost revenues associated with fixed costs only.

Three-year plan in isolation. In order to isolate the impacts on rates and bills from the proposed three-year plan, we do not account for lost revenues from the programs implemented in previous years, which varies from the utilities' lost revenue calculations. This way, stakeholders can review how the proposed efficiency plan will impact rates and bills over the long term, without the influence of prior or future plans. The approach to not include lost revenues from previous years will likely understate rates and bills slightly. However, the net change in rates in bills between pre- and post- efficiency would not vary much if the prior lost revenues were included in both the No EE and EE Scenarios. It is important to note this method is only appropriate for the purpose of reviewing the impacts of the energy efficiency plan and is not intended to be used as a substitution for a traditional utility rate impact assessment.

Annual reconciliation. One of our simplifying assumptions is that the utilities recover energy efficiency lost revenue every year in the year the lost revenue occurs. In practice, there is often a regulatory lag

[16] At the time we developed the model, two New Hampshire utilities had open rate cases where decoupling mechanisms were potentially subjects for further investigation.

from when the utilities experience the reduction in sales and when they can adjust rates to collect the lost revenue from efficiency programs. However, the New Hampshire utilities that collect lost revenue through the SBC or LDAC rate adjust those rates annually, so there is less of a lag.

Distribution Lost Revenue

Most of a utility's distribution costs are fixed costs, associated with investments in the distribution system. Therefore, these fixed costs should be recovered through a lost revenue recovery mechanism.

We calculate distribution lost revenue based on the difference in pre-efficiency and post-efficiency sales, as summarized in the following equation.[17] This method isolates the change in sales from efficiency while maintaining the fixed, post-efficiency revenue requirement, such that the rate impact for lost revenues is based on the change in sales only.

$$\frac{Post\text{-}efficiency\ Revenue\ (\$)}{Post\text{-}efficiency\ Sales\ (kWh)} - \frac{Post\text{-}efficiency\ Revenue\ (\$)}{Pre\text{-}efficiency\ Sales\ (kWh)}$$

where:

- Post-efficiency revenue is the pre-efficiency distribution revenue less any avoided distribution costs.
- Pre-efficiency sales are the sales as entered into the model by the utilities.
- Post-efficiency sales are the pre-efficiency sales less the proposed savings from efficiency.

Transmission Lost Revenue (electric utilities only)

ISO New England sets the transmission rates for pool transmission facilities for the entire New England region. Each load-serving entity in New England (including each New Hampshire electric utility) pays the same rate for pool transmission facilities.[18] Utilities then collect these costs from ratepayers through their respective transmission charges.

ISO New England updates the New England transmission charge each year to reflect annual changes to costs and sales. Any lost transmission revenues from one year are corrected in the following year, and thus are mostly recovered.

[17] We show kWh in the equation, but we use the same calculation for kW and therms when calculating lost revenue from electric demand distribution rates and from gas distribution rates, respectively.

[18] See, e.g., ISO New England, "New England Control Area Transmission Services and ISO-NE Open Access Transmission Tariff General Business Practices," August 8, 2019, available at: https://www.iso-ne.com/static-assets/documents/2016/05/rto_bus_prac_sec_2.pdf.

ISO New England sets the same rate for all load-serving entities. Therefore, the actions of one load-serving entity are felt by all load-serving entities in the region. If New Hampshire utilities reduce load through efficiency programs and thereby create lost transmission revenue, all load-serving entities in New England experience a transmission rate increase to recover any fixed transmission costs. However, New Hampshire ratepayers will only see a small share of that increase once it is distributed across all load-serving entities.

In the rate and bill impact analysis, we focus only on impacts to New Hampshire ratepayers from energy efficiency resources. When calculating transmission lost revenue, we estimate the New Hampshire-specific portion of lost revenues created by New Hampshire utilities implementing efficiency programs. We do this by estimating New Hampshire's portion of regional transmission demand, which we estimate is 9.54 percent using ISO New England data.[19]

4.2. Electric Capacity

For the electric rate and bill impact model, we assume all types of peak demands are coincident with each other. In practice, there are different types of capacity impacts, with different capacity definitions assumed by efficiency program planners, infrastructure system planners, and utilities when designing rates. For example:

- *Generation* costs are based on ISO New England's Forward Capacity Market charge, which assesses costs based on a utility's load during the annual peak hour on the regional transmission system.
- *Transmission* charges for pooled transmission facilities are based on the monthly peak load for each transmission provider.
- *Distribution* costs are specific to each distribution utility's system.

The peak usage for generation, transmission, and distribution can occur at different times. Further, customer demand charges are often based on a customer's highest demand in a month or year, which could differ from generation, transmission, and distribution peaks. Finally, efficiency program capacity savings are typically coincident with generation peak periods.

To accurately account for each capacity definition in the electric rate and bill impact model, the utilities would need to provide very detailed data. The utilities would need to provide the coincidence of the customer's monthly peak usage relative to the generation peak, which likely requires hourly customer usage and savings data. Utilities would also have to estimate savings coincident with each type of peak (generation, transmission, and distribution). Due to the complexities in obtaining this data and the fact

[19] ISO New England, "Monthly Regional Network Load Cost Report November 2019," January 14, 2020, page 25, Table 7-1, available at: https://www.iso-ne.com/static-assets/documents/2019/01/2018_11_nlcr_final.pdf.

that the benefit-cost models do not distinguish between these different peaks, we do not think this level of detail is necessary in estimating average rate and bill impacts.

4.3. Three-Year, Long-Term Impacts

The New Hampshire utilities plan and implement three-year energy efficiency plans. We built the rate and bill impact models such that the model user can view calculations and results for each individual year of the plan and for the three years combined.

We calculate rate and bill impacts over the long term, meaning for the life of the efficiency measures installed. For the New Hampshire utilities, there are several programs with measures that extend out to 25 years—such as those included in the HVAC and EnergyStar Homes programs. In order to account for measures that extend beyond the average measure life of the efficiency program portfolio, we use 25 years as the study period for each individual year, which results in a 27-year study period for the three-year plan term. We define “long-term” consistent with the study period of 25 years for each year of the plan term. Further details on the use of a long-term study period are provided in Appendix A.

4.4. Measure Life

We use a weighted average measure life to estimate the length of time that benefits and lost revenue will impact each rate class. Specifically, we divide lifetime savings by annual savings to determine the weighted average measure life at the sector level, and round to an integer number of years. By using a weighted average measure life in the rate and bill impact models, we assume all savings will expire at the end of the average measure life. Without conducting an analysis of each program within a sector, this is the optimal way to account for savings at the sector level.

In reality, each energy efficiency measure has a different measure life, and savings will gradually dissipate over an extended period. The utilities account for individual measure lives in their benefit-cost screening models. They calculate benefits using measure-specific lifetimes that range between 1 and 25 years. To account for the impact of measures that will continue producing savings beyond that average sector measure life, the long-term rate and bill impacts are calculated over a 25-year period as further explained in Appendix A.

Figure 1 illustrates the difference in savings over time using either an average measure life as calculated in the rate and bill models or the actual distribution of measure lives over time as included in recent benefit-cost screening models.[20] Using a weighted average measure life condenses the savings period

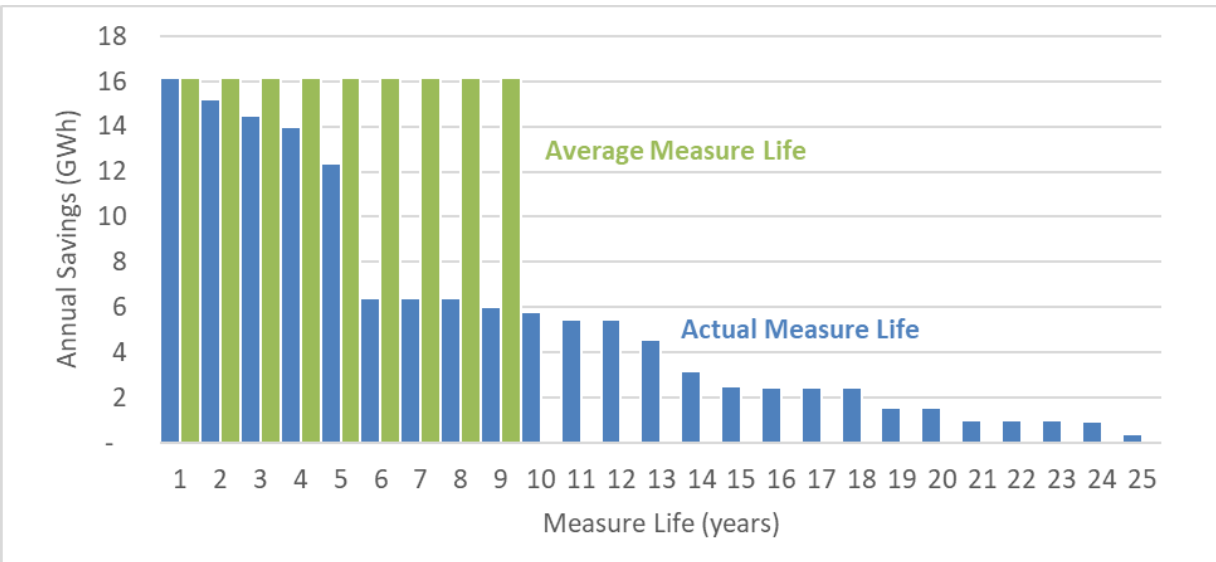
[20] To develop this figure, we used Eversource’s residential savings from its 2020 plan update. We provide this figure to illustrate the difference in measure life calculations and its inclusion should not be a reflection on Eversource’s savings data.

and assumes all savings occur within that weighted average at the level equal to the savings in the first year.

To test the robustness of this assumption, we conducted a sensitivity analysis where we first used the actual distribution of residential program measure lives over time from the benefit-cost screening models in the electric rate and bill impact model. We then compared that to using a weighted average measure life in the model. We found that rate and bill impacts using the actual measure life distribution compared to the use of a weighted average measure life at the sector level were within 1 percent of each other in the early years of the analysis period, and the long-term averages were within 2.5 percent.

While the actual measure life distribution approach is more accurate, we found our simplified approach balances accuracy with the illustrative nature of the rate and bill analysis. It is an appropriate method to illustrate the impacts on customers' rates and bills over the long term.[21]

Figure 1. Annual savings using an average measure life or actual measure lives



4.5. Conclusion

The simplifying assumptions described above have been made out of necessity, and the actual rate or bill impacts for a specific customer or year can vary from the estimates here. For these reasons, the assumptions used in this analysis are meant to provide an approximate indication of the rate and bill impacts that will occur over the long term from the implementation of an energy efficiency plan. The results of the model are meant to provide a useful data point in the overall assessment of energy efficiency plans, and for considering any tradeoffs that might exist between cost-effectiveness and rate

[21] Alternatively, the utilities would need to enter measure life-specific savings into the rate and bill impact models, and we would have calculated benefits in the model using avoided costs. We find the benefit-cost screening tools are a more appropriate model for calculating benefits.

impacts. As such, the results of this analysis should be viewed as general, long-term indications of rate and bill impacts, and not a precise forecast of impacts in any one year. The results of this model are not intended to replace or replicate the detailed analyses utilities undertake when calculating rates for efficiency cost recovery through the SBC for electric utilities or the LDAC for gas utilities.

5. Rate and Bill Impacts: Inputs and Considerations

In this section, we provide an overview of the types of inputs the utilities need for the rate and bill impact models and explain items stakeholders and utilities should consider when determining those inputs.

5.1. Energy Efficiency Inputs

The “EE Inputs” tab of the rate and bill impacts models is where utilities should enter the efficiency data used throughout the model. The utilities provide efficiency inputs for each year of the plan and by customer sector for both the Proposed Efficiency scenario and the Alternative Efficiency scenario. The utilities should determine all efficiency inputs and can work with the EM&V Working Group as needed to estimate certain inputs that are more subjective, such as the Alternative Efficiency scenario inputs.

Proposed and Alternative Efficiency Scenarios

For the Proposed Efficiency scenario, we anticipate that the utilities will populate the inputs with data directly from their benefit-cost screening models. All the efficiency inputs are within the benefit-cost screening models, and the utilities could add a new tab to their screening models with the rate and bill impact data already formatted for input into the rate and bill models. This would make it easy for the utilities to update the rate and bill impact models once they finish measure-level planning in the screening model.

The Alternative Efficiency scenario could represent any efficiency scenario chosen by the utilities and the EM&V Working Group. As examples, the utilities could model the impact from more heat pumps and weatherization, a general 20 percent budget increase, or fewer lighting measures.

We worked with the EM&V Working Group to develop two options for inputting the Alternative Efficiency scenario into the models. Under one option, the utilities use percentages to adjust the Proposed Efficiency scenario for budget, cost of saved energy, and savings per participant (using the "% Change" option in the dropdown menu on the “EE Inputs” tab). The other option has all the same inputs as the Proposed Efficiency scenario. With this option, the utilities model a different set of efficiency inputs in an alternative benefit-cost screening analysis, and manually enter the values into the rate and bill impact model (using the "User Input" option in the drop-down menu on the “EE Inputs” tab). This second option could be used, for example, if a stakeholder wanted to see the impact on rates and bills from investing in more fuel switching technology than the utilities include in their proposed efficiency plans. The utilities could adjust the fuel switching assumptions directly within the benefit-cost screening analysis, then add those new results as inputs to the rate and bill impact models.

Input Detail

Below, we identify the energy efficiency inputs for both the electric and gas rate and bill impact models. We also indicate how we use each input throughout the rate and bill impact models.

Utility Costs: the utility's cost to implement the efficiency programs that are paid by ratepayers. We do not use these costs within the rate calculations explicitly. Instead, the efficiency portion of the SBC or LDAC rate is used throughout the model for the rate impact calculations. We use the utility costs to adjust the Alternative Efficiency scenario SBC or LDAC rate, regardless of which Alternative Efficiency scenario input method the utilities use.

EE Portion of SBC or LDAC Rate: the efficiency portion of the SBC or LDAC rate (in $/kWh or $/therm) the utility proposes to collect from ratepayers.[22] We use this rate to determine the upward pressure on rates from energy efficiency in the years the three-year plan is implemented. This method isolates the impact of the energy efficiency charge and does not include the lost revenue recovery portion of the SBC or LDAC rate. Section 4.1 describes the calculation of lost revenue recovery.

Electric Savings (Net): annual and lifetime energy savings (in MWh or MMBTU), as well as summer capacity (in kW) in the electric model. We use savings for many purposes throughout the models—including calculating average measure life, adjusting pre-efficiency sales to determine post-efficiency sales and bill reductions for the average customer.

Utility System Benefits: the utility system benefits for electric and gas utilities. For electric utilities, the benefits include distribution, transmission, energy, energy DRIPE, capacity, capacity DRIPE, and reliability. For gas utilities, benefits include avoided gas and gas DRIPE. We reduce the utilities' revenue requirements for each rate type by the corresponding benefits to determine rate impacts over the long term, using the average measure life of efficiency measures installed in each customer sector.

5.2. Rate Inputs

The "R&B Inputs" tab of the rate and bill impact models is where the utilities enter their rate and bill data used throughout the model. The utilities provide rate inputs such as sales, number of customers, and current rates for each of the four modeled rate classes.

We structured the models so the utilities can analyze different rate structures, such as demand rates for electric utilities and seasonal rates for gas utilities. As such, not all inputs will be applicable to every rate class.

[22] At the time we developed the models, stakeholders in New Hampshire were considering adjusting how the utilities calculate the efficiency rates. In previous years, the utilities calculated a single rate for all electric or gas utilities that was applicable to all rate classes. For the 2021–2023 Plan, stakeholders were considering other approaches, such as amortizing the rate or using a distinct rate for each utility and rate class. As a result, instead of calculating an efficiency rate within the models directly, we made the efficiency rate an input into the models.

For gas utilities, the model calculates annual rate and bill impacts. Gas rates, customer usage, and energy efficiency savings are typically seasonal, weighted towards higher winter heating demand. For this reason, the model separately identifies many of the gas rate and bill inputs by summer and winter, then combines them to determine weighted average annual impacts.

For electric utilities, the model calculates monthly bill impacts.

Input Detail

For each of the four modeled rate classes, the utilities provide two types of inputs: rate class data and current rates. Below, we define those inputs, explain how the inputs are used within the models, and identify any distinctions between the electric and gas models.

Each model has definitions of every input on the "R&B Inputs" tab, which describe how inputs are used throughout the model. Given the number of inputs and the variations between the electric and gas models, we have not repeated that level of detail in this report. Instead, the high-level overview below describes the general categories of inputs the utilities need to provide and highlights considerations for stakeholders to discuss when populating the rate inputs.

Rate class data inputs are as follows:

- *Rate class name:* identifying information about the rate class modeled. This data is informational only and is not used in model calculations.
- *Customers*: the number of customers taking services under the rate class. Utilities have the option to enter customers for a single year or for multiple years.[23] The models use this data to estimate bill savings for the average customer.
- *Sales:* the sales (in kWh or therms) for the rate class. As with the customer inputs, the utilities have the option to enter sales for a single year or multiple years. Gas utilities enter sales for both the summer and winter periods. Sales are a key model input, as the models use sales data throughout to calculate rate impacts.
- *Peak Demand:* the annual customer peak demand for the rate class. This input is included in the electric model only and is only applicable if the electric rate class uses demand charges. If the rate class uses demand charges, then the model uses the peak demand data similarly to how it uses the sales data to determine rate impacts. As noted in Section 4.2, the model assumes the customer peak demand coincides with system peak demand. However, the model is set up to allow the user to adjust the percentage to a utility-specific customer coincident peak that differs from the system peak.
- *Typical customer usage:* the typical energy consumption for the rate class, either in monthly kWh and kW for electric rate classes or in annual summer and winter therms for gas rate classes. The value should be relatively consistent with the typical customer

[23] If entering customers for multiple years, the utility does so on the "Multi-Year Inputs" tab of the model.

usage the utilities use when calculating bill impacts in other rate-setting proceedings. The models use this data to estimate bill impacts.

- *Rate Type Data:* for rate classes that use block or peak period pricing, the threshold consumption levels and billing determinants (e.g., sales by the different blocks). The models use this information to determine weighted average rates for use in both the rate and bill impact analyses.

Current rate data inputs are as follows. The models use these inputs to determine both the rate and bill impacts.

- *Customer or Meter Charge:* the minimum monthly charge per customer for the rate class. The models convert dollars per month to dollars per kWh or therm to put all monthly or annual charges in consistent units for the purpose of presenting results in terms of dollars per kWh or therm. The customer charge is not impacted by energy efficiency, but the models use it to calculate the total percent change in rates and bills.

- *Distribution Charges:* the utility's distribution rates for the rate class, broken into blocks or other pricing periods as needed. For electric utilities, the distribution charges include not only distribution rates, but, where applicable, rates for stranded costs, storm recovery costs, and the Electric Assistance Program (EAP) portion of the SBC. The electric utilities do not combine these rates into the distribution rates, but the rates are similarly impacted by energy efficiency resources and represent fixed costs that will result in lost revenue. Therefore, as a simplifying assumption, the models group the rates together when calculating the rate and bill impacts.

- *Transmission Charges (electric only):* the electric utility's transmission rates for the rate class, broken into blocks or other pricing periods as needed.

- *Supply Charges (electric only):* the current electric supply charge for the utility's service territory for the rate class.

- *EAP Information (electric only):* inputs for the low-income rate, such as the discount from the electric rate, and the consumption threshold for applying the low-income discount. This information is specific to the low-income rate class for electric utilities only. See *Electric Low-Income Rates*, below.

- *LDAC (gas only)*: the gas utility's summer and winter LDAC rates for the rate class. The LDAC recovers other operating and maintenance costs not reflected in the distribution charge.

- *Cost of Gas Charge (gas only):* the gas utility's summer and winter gas rates for the rate class.

Choosing Rate Classes

Rate impacts can be markedly different across different customer types. Therefore, it is useful to analyze the rate impacts for key customer sectors.[24] We designed the rate and bill impact models to analyze one rate class for each of the four key customer sectors: residential, low-income, small commercial, and large commercial. These four customer sectors are consistent with the sectors served by the utility's efficiency programs. We worked with the utilities to identify the rate class that should represent each customer sector while drafting the models.

C&I Rate Classes

Electric and gas utilities typically have multiple rate classes for C&I customers, reflecting the varied energy use profiles for C&I customers. Further, C&I rate classes can be more complicated than residential or low-income rate classes. As examples, some utility C&I customers take service under demand charges, block rates, time-of-use rates, or other complex rate designs. Another complicating factor is that the rate designs for commercial classes vary across utilities.

In general, we recommend modeling the rate classes for which most customers take service, to understand the rate and bill impacts most customers could experience from energy efficiency resources.

Electric Demand Rates

The rate class modeled for a customer sector could impact the rate and bill impact results, especially for electric rate classes that use demand rates. The rate and bill impacts for a specific rate class can be driven by the balance between energy and demand rates and energy and demand efficiency savings.

An electric commercial rate class could be structured to collect revenue primarily through demand charges, and the efficiency programs serving that customer sector could save a higher portion of energy than demand. As a result, the rate impact for the rate class may be impacted differently from a rate class that does not have demand charges.

Similarly, customers with demand rates will see different bill impacts depending on the efficiency measures they install. For example, the transmission rate for Eversource's large C&I customers is demand-only (calculated on a per-kW basis), without an energy rate component (in kWh). If a large C&I participant installs efficiency measures with high energy savings and relatively low demand savings, that customer will not see a reduction in the transmission portion of its electric bill.

Electric Low-Income Rates

Unlike the gas utilities, the electric utilities do not have an explicit low-income rate class. Instead, they provide a discount to residential customers who qualify, as a subset of the residential rate class.

[24] NESP, page 125.

The electric low-income bill discount ranges from 8 percent to 76 percent depending on the customer's income as a percent of federal poverty guidelines, which the utilities categorize into six tiers. For example, a customer in Tier 4 has an income between 101 and 125 percent of the federal income poverty guidelines and receives a 36 percent discount on their electric bill.[25] We drafted the electric model using the Tier 4 discount, but the utilities and stakeholders should review the number of customers taking service on the low-income rate and adjust the inputs to reflect the tier under which most customers take service.

For all tiers, the utilities apply the low-income discount to only the first 750 kWh the customer consumes in a month. In this way, the low-income discount functions like a block rate, which is how it functions in the electric rate and bill impact model.

Rate Input Considerations

Below, we highlight key inputs and assumptions that utilities and stakeholders should consider when populating the models and reviewing model results.

Annual Escalation Rates

For most inputs on the “R&B Inputs” tab, the models have an annual escalation rate that the utilities can use to forecast the input over the long term. For example, the utilities could assume that the number of customers in the rate class will increase 1 percent annually, or that the monthly customer charge will increase 0.5 percent annually.

In the draft models, we did not apply any of the escalation rates (i.e., we set them all to 0 percent), implying no annual growth for any of the rate class inputs. Since the model represents rates in real (inflation adjusted) terms, a 0 percent growth rate means that rates will escalate at the rate of inflation. Stakeholders can review and adjust these assumptions as appropriate by utility, rate class, and input.

Weighted Average Rate

Where the modeled rate class uses dynamic rates such as block rates for electric utilities or summer and winter rates for gas utilities, the models calculate a weighted average rate. This weighted average rate then becomes the rate used to determine rate impacts for the rate class. The models weight the rate components by the billing determinants (e.g., sales for each block period).

We calculate a weighted average rate because calculating rate and bill impacts for each dynamic rate structure would over-complicate the model calculations and imply a false level of precision.

[25] See, e.g., NHPUC Order No. 26,347 in Case No. DE 20-039, dated April 10, 2020 Unitil Electric Systems, Inc., https://unitil.com/sites/default/files/tariffs/SumofLI_06.01.20.pdf.

Electric: Energy and Demand Components

Some electric rate classes have both energy (kWh) and demand (kW) charges for the distribution and/or transmission component of the rate structure. For such rate classes, the electric utilities need to populate two additional inputs.

Revenue Allocated to Energy: The utilities need to indicate the amount of revenue that they allocate to the energy portion of the rate. The utilities should populate this percentage based on how they allocate revenue between energy and demand components for the rate class. The models use this percentage to allocate avoided distribution and transmission costs between the energy and demand rates. The impacts that avoided costs have on energy and demand rate components are likely to differ from the utilities' allocation of revenue requirements for past investments. For example, revenue requirements include fixed costs that are typically unavoidable (e.g., customer meters, distribution poles). However, using an allocation based on revenue requirements is a reasonable proxy, given that we do not know exactly how avoided costs will ultimately impact the utilities' rates.

Load Factor: The model for electric energy efficiency presents rate impact results in three different units—cents per kWh for energy-related cost impacts, dollars per kW for demand-related cost impacts, and cents per kWh for all cost impacts combined (both energy- and demand-related costs). For the "all in" cost impact in cents per kWh, the model uses a load factor to convert dollars per kW impact into cents per kWh to put all charges in consistent units. The models calculate the load factor based on the rate class' sales and peak demand use, but the utilities should review and confirm the resulting factor.[26] A load factor of 100 percent implies that the customer's load is completely flat, while a load factor of 1 percent implies that the customer primarily uses energy during the system peak hours, assuming the customer peak and the system peak occur during the same hours.

Other Considerations

Discount Rate

The model applies a real discount rate in determining the NPV and levelized change in rates and bills over the study period. The discount rate found in the "Lookups" tab is derived from the NH utilities' July 1 draft of the 2021-2023 Plan.

- Nominal discount rate is based on the June 2020 Prime Rate in accordance with the Final Energy Efficiency Group Report, dated July 6, 1999 in DR 96-150. Retrieved from http://www.moneycafe.com/personal-finance/prime-rate/
- Inflation rate is based on the inflation rate from Q1 2019 to Q1 2020, Retrieved from https://fred.stlouisfed.org/data/GDPDEF.txt

[26] The specific formula is sales (in kWh) divided by demand (in kW) that has been multiplied by the 8,760 hours in the year.

- Real Discount Rate = [(1 + Nominal Discount Rate)/(1 + Inflation Rate)] – 1

5.3. Bill Inputs

All customers experience a rate impact from efficiency programs, which results in a bill impact. However, customers that participate in the efficiency programs will see an additional impact on their bills through reduced consumption. In this section, we highlight some of the key inputs and considerations for the bill impact analysis.

Types of Customers

The models present bill impacts for four different types of customers: non-participants, average customers, high-savings participants, and low-savings participants.

Non-Participant: By not installing efficiency measures, non-participants' consumption is unchanged from efficiency programs, and their bills are only impacted by the rate impacts. Therefore, non-participants experience bill impacts that are proportional to the rate impacts.

Participant: By participating in efficiency programs, customers reduce their electricity consumption, thereby lowering their bills. The efficiency measures that a participant installs determine the size of the bill reduction. The combination of reduced electricity consumption and the rate impacts provide the bill impact for program participants.

Average Customer: An average customer represents an average bill across all customers, both non-participants and participants. It does not represent a specific customer or participant. Instead, it is intended to provide an indication of how the efficiency programs affect customer bills on average. The models calculate the average customer's bill "savings" for each customer sector as energy savings divided by customers.

Participant Bill Savings

A participant's bill impact could vary significantly depending on the number and type of efficiency measures installed. For example, a participant could install a single LED lightbulb which would provide modest bill reductions, or a participant could undertake a deep energy retrofit which would provide substantial bill reductions.

To account for such variation in participant bill impacts, the models account for two types of participants. The utilities and stakeholders can define these participants as they see fit, with corresponding estimated bill reductions. While we provide optionality within the model, we expect the utilities will estimate bill savings for a participant with a low level of savings and a participant with a high level of savings. Such an approach bookends the range of bill impacts experienced by participants, indicating to stakeholders that most participants will experience a bill impact within that range. Alternatively, stakeholders could agree to model an average participant and a high or low participant, or some other combination of potential program participants.

There are several methods the utilities could use to estimate the savings per participant for the two types of participants. The utilities could estimate savings per participant using historical participant savings data, calculating average savings per participant proposed in the plan for select programs, or through other means agreed upon with stakeholders. The participant savings could represent a customer that participates in a specific program, such as the Home Energy Reports program or the Home Performance with Energy Star program. Regardless of the method agreed upon by the utilities and stakeholders, it is important that model users remember the results are meant to be illustrative, and that each participant will have a different bill impact depending on the types of efficiency measures installed.

The "EE Inputs" tab provides the utilities two input methods for savings per participant: (1) a percent reduction in typical monthly or annual consumption (which the utilities provide as part of the rate and bill inputs), or (2) monthly savings in kWh, kW, or annual savings in therms. The utilities enter savings for each year of the plan, by customer type, for both the Proposed and Alternative Efficiency scenarios.[27] The models then use these savings assumptions to determine the bill impacts for the two types of participants.

[27] For the bill impact results for the three years of the plan combined, we assume a customer participates in the first year of the three-year plan at the level of savings indicated for the first year of the plan.

6. RATE AND BILL IMPACTS: EXAMPLE RESULTS

The rate and bill impact models provide several outputs to summarize the impact of efficiency programs on customers' rates and bills, and they present rate and bill results in a meaningful context. For example, rate impacts are summarized in terms of cents per kWh, dollars per therm, dollars per month, and percent of total rates, while bill impacts are presented in terms of dollars per month and percent of total bill.

The sections that follow highlight some of the key model outputs that the utilities and stakeholders can use to asses customer equity impacts from the efficiency programs.

In the sample outputs below, we reference the utilities' 2021–2023 plan drafts from April 1, 2020 to illustrate the type of outputs included in the RBP models.[28] The April efficiency plans are not final and are subject to change. The results are illustrative only and are not intended to indicate the rate and bill impact results for any utility or plan.

For the purposes of illustration, we summarize results from Eversource's plan, and only for the residential rate classes.[29] The rate and bill impact results for the other utilities and rate classes can be found in the April efficiency plan draft. We show limited, focused results to provide consistency in this report, to reduce the volume of figures with similar results, and because the underlying data is subject to change based on the utilities' planning process.

6.1. Using the Results Tabs

We built the rate and bill impact results tabs to be dynamic for the year(s) modeled. The model user selects the plan year or the three-year total from the "Program Year(s)" drop-down menu to adjust the results. By default, the models are set to the three-year total to summarize the impact from the entire proposed plan.

If looking at results for a single year, the figures summarize the long-term impacts from investments made in that year. If looking at results for the three years in total, the figures summarize the long-term impacts from the utility's investments made over the three-year term.

6.2. Change in Revenue Requirements

To synthesize the rate impacts across the customer sectors, the models provide an indication of the net change in the utility's revenue requirement due to the proposed efficiency programs. The change in

28 See, Draft 2021-2023 New Hampshire Statewide Energy Efficiency Plan, April 1, 2020, Attachment K.

29 We chose Eversource because it represents the largest electric utility in the state by sales volume.

revenue is dispersed across each rate class differently, depending on the efficiency programs and the rate class structures. Each rate class will experience a different change in revenue and therefore rate impact.[30] A summary of the change to revenue requirements can be found in the "Output Summary" tab of the models.

6.3. Summary Table

Each model provides a table summarizing the rate and bill impacts by year, customer sector, and Proposed Efficiency or Alternative Efficiency scenario shown on the "Output Summary" tab.[31] Table 1 provides an example of that summary table for Eversource's residential rate and bill impacts. A non-participating Eversource residential customer could see a 0.5 percent bill increase over the 27 years of the three-year plan, while a customer participating in an efficiency program with high-savings measures could see a bill decrease of -2.6 percent, and customers on average could see a slight bill increase of 0.02 percent. Though not shown here, the summary tables for the C&I sector provide the additional detail of changes in demand rates.

Table 1. Electric residential long-term levelized rate and bill impacts from 2021-2023 Draft Plan

Residential		Levelized Net Change
Change in Annual Rates		
Total Rates	¢/kWh	0.08
	%	0.5%
Change in Monthly Bills		
Non-Participant	$	$0.52
	%	0.5%
Average Customer	$	$0.02
	%	0.02%
Low Savings Participant	$	$0.17
	%	0.2%
High Savings Participant	$	-$2.90
	%	-2.6%

30 As we explain in Section 3.1, avoided electricity costs and avoided gas costs do not impact rates, and instead are accounted for in bill impacts. For the revenue requirement assessment, the models assume the utilities' revenue requirements will be impacted by changes in avoided electricity and avoided gas costs.

31 The utilities did not include this table in their April 1 plan drafts, but we provide example results here as it is an important output from the models.

6.4. Rate and Bill Impact Figures

The rate and bill impact models present various figures and results which may be of interest to stakeholders, including total rates and bills, percent changes in rates and bills, and bill impacts for each year of the three-year plan.

Figure 2 and Figure 3 illustrate two results from the models, summarizing rate and bill impacts, respectively, for residential programs. Both figures show results for all three years of the plan and represent the long-term average change in rates and bills for the Proposed Efficiency scenario relative to the No New Efficiency scenario. Additional utility-specific figures are found in the model. It is important to note that figures in the model for C&I rate classes with demand charges are based on taking demand charges (in $/kW) and converting them to energy charges (in $/kWh) using a rate class-specific load factor to include all rates in a single figure. However, the model generates a summary table in the “Output Summary” tab which presents rate impact results in three different units as explained above: cents per kWh for energy-related cost impacts, dollars per kW for demand-related cost impacts, and cents per kWh for all cost impacts combined (both energy- and demand-related costs).

In the figures below, we use Eversource’s residential three-year plan as an example. The rate and bill impacts for other utilities and rate classes demonstrate a similar pattern, although the magnitude of each impact varies depending on the efficiency programs for the rate class and the rate class structures.

Figure 3 summarizes the change in rates for each year over the defined long-term study period of the residential efficiency programs proposed in the 2021-2023 Draft Plan, compared to if there were no Plan. We separately identify the change in rates as follows:

- Yellow bars: energy efficiency cost recovery associated with the efficiency plan through the SBC for electric utilities and through the LDAC for gas utilities
- Red bars: lost revenue associated with the efficiency plan
- Green bars: avoided costs associated with the efficiency plan
- Black dotted line with %: net change in rates, which accounts for the upward pressure on rates from efficiency costs and lost revenue recovery, and the decrease in rates from avoided costs. The percentage of net change in rates is shown in this table for each year above the dotted line.
- Text box: provides the levelized net change in rates.

As the figure shows, efficiency costs are recovered in the first three years of the plan, while benefits accrue each year over the long term. Savings, which impact both avoided costs and lost revenue, phase in during the first three years before phasing out at the end of each year’s average measure life. In each year and over the long term, avoided costs and lost revenue almost net each other out. This impact combined with the three years of initial cost recovery results in a levelized net increase in rates of about 0.5 percent.

Figure 2. Eversource Proposed 2021-2023 Draft Residential Programs levelized long-term rate impacts[32]

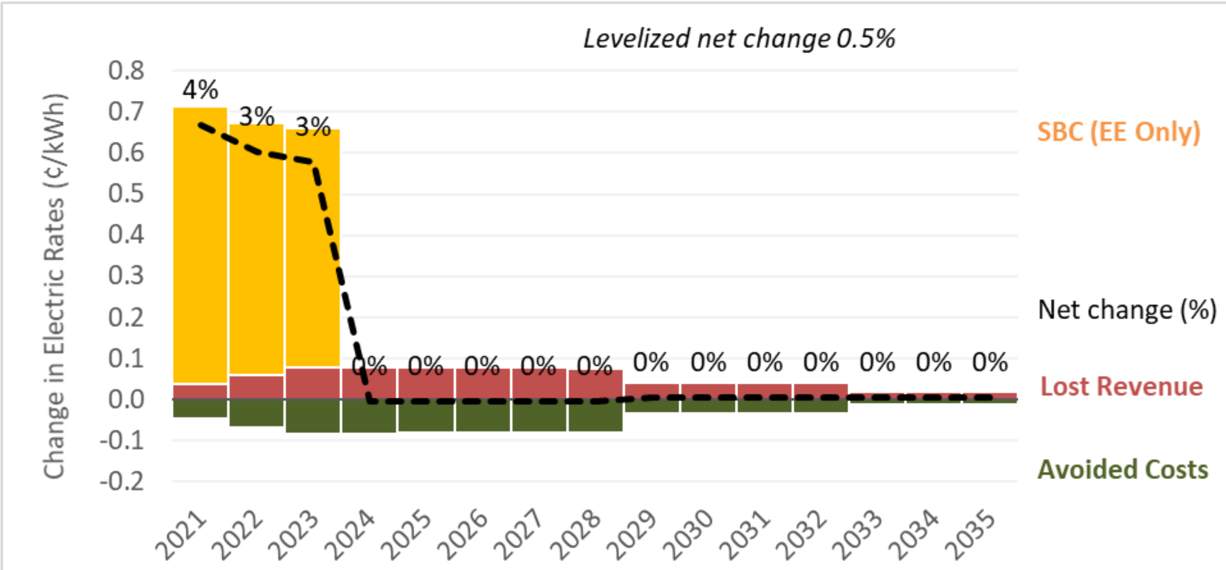
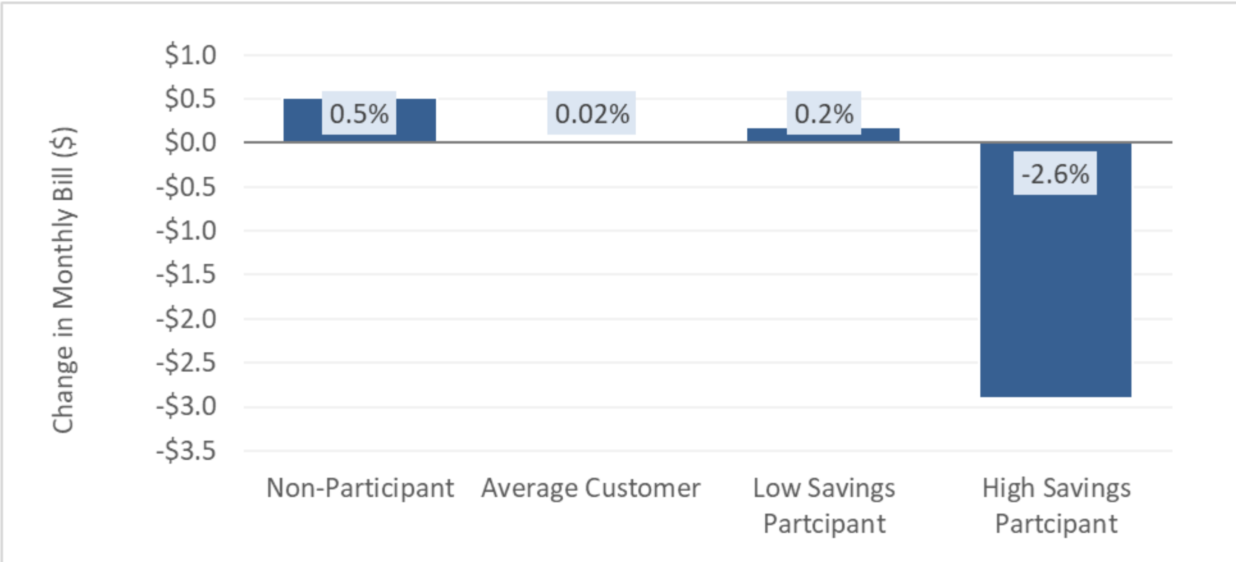


Figure 3 summarizes the bill impacts for each customer type as a total change in bills (in dollars) as shown in the blue bars, and as a percent change in bills, as shown in text boxes. The non-participant sees a 0.5 percent bill increase, consistent with the change in rates. Customers on average see almost no bill impact (a 0.02 percent increase). Participant bill impacts range from a slight increase of 0.2 percent to a decrease of 2.6 percent, depending on the efficiency measures the participant installs during the three-year plan.

[32] This figure is for illustration only and is not considered a final result.

Figure 3. Eversource Proposed 2021-2023 Draft Residential Program long-term bill impacts[33]



[33] This figure is for illustration only and is not considered a final result.

7. PARTICIPATION ANALYSIS

Customers that participate in efficiency programs will typically experience reduced bills while non-participants might experience increased bills. A comprehensive understanding of the equity issues raised by energy efficiency programs requires assessing the efficiency program participation rates to identify the extent to which some customers benefit more than others. We estimate participation rates based on the percentage of eligible customers that could participate in efficiency programs.

Analyzing program participation is complicated. Stakeholders need to consider issues such as customers participating across multiple programs within a year, customers participating in a single program but across multiple years, definitions for a participant in each program, and customer eligibility for each program.

7.1. Model Overview and Key Assumptions

We developed an Excel model to analyze efficiency program participation in New Hampshire. We developed this analysis separately from the rate and bill impact analysis models because the inputs and results vary between the two analyses. The participation model is intended to accompany the rate and bill impact model, as we explain in the *Using the Models* section.

The participation model is the same for both electric and gas distribution fuels because inputs are program-specific, and the utilities offer the same programs across fuel types. The model analyzes one utility at a time, and results are utility-specific. Like the rate and bill impact models, we expect each utility will make a utility-specific version of the participation model and maintain the model inputs to reflect current energy efficiency data.

The model presents results in terms of annual and cumulative participation by sector and program, both as a percent of eligible customers and in absolute terms (e.g., unique accounts participating).

Defining Participants

Ideally, the New Hampshire utilities should define participants as unique accounts for all programs. This is the ideal approach to defining program participants because it allows for proper accounting of customers that participate in multiple programs within a year or across years. This allows for an accurate comparison of participation rates across programs and years.

However, the definition of a participant could vary by efficiency program, and the utilities may find it challenging to identify unique participants depending on the program. As examples, participants in the residential Home Energy Reports program are relatively easy to define: participants are the number of homes that receive a report regarding the home's energy use. It could be more challenging for the utilities to identify unique participants in an upstream efficiency program, where the utilities cannot trace a product purchased from a store to a customer's home or business. In such instances, the utilities may need to make simplifying assumptions, such as that a customer purchases four lightbulbs per home.

Eligible Participants

To determine a participation rate, the model divides program participants by the number of customers who could have participated in a program (i.e., the eligible participants). For example, the pool of eligible participants for a residential program could be all the utility's customers taking service under the residential rate class. The definition for eligible participants could vary by program, especially within C&I programs for small and large customer, but the pool of eligible participants should remain consistent across each program by year.

Repeat participants

Customers can participate across multiple years within the same program, and/or across multiple programs within a year. For example, a residential customer could easily participate in both the Home Energy Reports program and the Home Performance with Energy Star program in a single year. Or, a customer could participate in the Energy Star Products program every year over a three-year plan or even multiple times within a single year.

If the participation model counted each customer every time he or she participated, the participation rate would be skewed and indicate more unique accounts participated than is the case. In some instances, customers can repeat participation frequently, resulting in a participation rate that exceeds the pool of eligible customers. This is especially the case with a program like Home Energy Reports, where many customers receive an energy report over multiple years. Similarly, the Energy Star Products program presents challenges for estimating repeat participants, because unique customers cannot be tracked for upstream programs. Such results do not help utilities and stakeholders assess the breadth of customers participating in efficiency programs who thereby reduce their energy bills.

We have tried to account for repeat participants in the participation model, isolating the number of unique accounts participating by program and by year. However, the analysis is only as sound as the utilities' participation data and the utilities' ability to isolate unique accounts.

Alternative scenario

We included an Alternative Efficiency scenario in the rate and bill impact models, but not in the participation model. We were uncertain the utilities could forecast participants for an alternative scenario that would be consistent with the alternative scenario modeled in the rate and bill impact analysis, depending on the complexity of an alternative scenario. We were also concerned that an alternative analysis could over-complicate the participation outputs, especially because the participation model is for a longer timeframe than the rate and bill impact analysis.

7.2. Inputs and Considerations

A participation analysis requires data indicating when a customer participated and in which program they participated. If the utilities do not currently have the data required to populate the participation model inputs, we recommend they begin collecting the data to complete the analysis for future efficiency programs. For example, the utility may not have historical planned and actual eligible participants, in which case planned and actual values can be the same. For future planning, however, utilities should be able to provide both planned and actual eligible participants.

We built the participation model such that customer-specific information (e.g., account number, street address) are not required inputs. However, the utilities may need to review such data prior to populating the model to correctly identify unique and repeat participants.

Below, we define and identify important considerations for each input. Some inputs are consistent across all utilities, which we pre-populated in the model. The other inputs are utility-specific and will depend on the utilities' historical and planned programs.

Pre-defined and pre-populated inputs

- *Year:* The participation model analyzes years 2017 through 2023. This analysis period varies from the rate and bill impact analysis, which is just for the three-year term of the proposed plan (2021–2023). We look at historical participation because cumulative participation is important for understanding long-term efficiency program impacts on customers' bills. For example, a customer could be a non-participant in the proposed three-year plan, but they may have participated previously. As such, that customer continues to offset the rate and bill impacts from the proposed plan, provided their efficiency measures are still in operation. We started the analysis in 2017 because the utilities confirmed that was the first year for which they could provide the requested data.[34] When updating the participation model for a new three-year plan, the utilities should not remove data for previous years, but instead should append the new plan data onto the existing analysis. This allows the utilities and stakeholders to view trends in participation over time and better assess the impact of the programs on customers' bills and customer equity over the long term.

- *Reporting Period:* The model includes both planned and actual participation. This differs from the rate and bill impact analysis, which analyzes planned data only. The model uses the actual participation data more than the planned data throughout. We provide a comparison of planned to actual participation for the program-specific analysis only.

- *Customer Sector:* The participation model analyzes residential, low-income, and C&I customer sectors. This is consistent with sector breakout the utilities use for their efficiency programs. The model then uses this input to summarize results by customer sector.

- *Program:* The model includes the efficiency programs the utilities have been implementing consistently since 2017: Home Energy Assistance, Energy Star Homes, Energy Star Products, Home Energy Reports, Home Performance with Energy Star, Large

[34] If the utilities find they can provide data even further back, we encourage them to update the model to accommodate those years.

Business Energy Solutions, Municipal Energy Solutions, and Small Business Energy Solutions.

Utility-specific inputs

Definitions, and information

The participation model is set up for each utility to enter in the below information. Each utility should make sure the below inputs match what it defined within the rate and bill impact model.

- *Equivalent Rate Class(es)*: The utilities should indicate which rate class(es) can participate in each program. This allows for comparison to the rate and bill impact analysis. It is important to note that the rate and bill impact analysis can only model one rate class per customer sector. The utility will have defined that rate class within its model.

- *Definition of Customers in Rate Class*: The utilities should indicate how they define the number of customers within a rate class, such as unique account, meter number, or something else.

- *Customers in Rate Class:* The utilities should indicate the number of customers taking service within the rate classes indicated under "Equivalent Rate Class(es)" for the indicated year. This allows for comparison to the number of eligible and annual participants.

- *Definition of Eligible and Participating Participants*: The utilities should indicate how they define both eligible and participating customers, such as unique account, meter number, or something else. The utilities should use the same definition for eligible customers and participating customers. Ideally, the utilities will define participants consistently with each other by program.

Participation data

The participation model uses the following data throughout to determine participation rates by sector and program.

- *Eligible Participants:* The utilities should indicate the number of customers that are eligible to participate in each program for the indicated reporting period and year, consistent with the definition of eligible participants. The number of eligible participants and the number of customers within the rate class could be the same, but do not have to be if the utility applies different definitions for the two types of data.

- *Annual Participants:* The utilities should indicate the number of customers that participated in each program or that the utility is expecting will participate in each program for the indicated reporting period and year, consistent with the definition of participating customers. This number should include all customers that participated in the year, including any repeat participants. The participation values are likely to be consistent with the participant numbers included in a utility's other planning documents and models, such as the benefit-cost screening model, and quarterly and annual reports.

- *Participants Across Multiple Programs:* The utilities should provide the number of customers who participated across multiple programs within the same customer sector for the indicated year and reporting period. The utilities should provide this value not by program but for the customer sector in total (residential, low-income, and C&I).[35] For example, if in 2017 a customer participated in both the Home Energy Reports program and the Energy Star Products program, then the utility should count that customer once in this input column. The model then subtracts these customers from the total annual participants for the customer sector such that each unique account is summarized in the sector-level results.
- *Participants Across Multiple Years:* The utilities should provide the number of customers who participated in the same program more than once since 2017 (the start of the participation analysis). The utilities should count a customer as a repeat participant for every subsequent year in which the customer participates in the program. For example, if a customer participates in 2017 and again in 2018 then that customer should be included in this input column for 2018. If that same customer participates again in 2019, it should be included in this input column for both 2019 and 2018.

For the last two data inputs on repeat participants, the utilities will need to forecast the expected repeat participants for each plan year and for each program. One approach the utilities could use for these projections is to assume a certain percentage of repeat participants based on historical program data, when such data is available.

7.3. Methodology

The participation model calculates both annual and cumulative participation rates. Annual participation rates represent the number of customers that participated in one year divided by the eligible participants that could have participated in that year. The model does not adjust the annual participants for repeat participation within the same program across multiple years but does adjust the annual participants for repeat participation across multiple programs at the sector level.

For the cumulative participation rate, the model estimates cumulative participation rates for each year and for the entire study period separately. The cumulative participation rate for each year is simply a sum of annual participation rates up to each individual year. The cumulative participation rate for the entire study period sums the annual participants and removes any participants who participated multiple times over the years and/or programs. It then divides the resulting unique participant count by eligible participants. For the sector participation rate, the model uses the eligible participants for the program in the sector with the most eligible participants. As mentioned above, the sector-level participation rates take into account repeat participant across multiple programs. The cumulative

[35] Specifically, on the "Inputs" tab of the participation model, the sum of participants across all programs within the customer sector less the customers in the "Participants Across Multiple Programs" column should indicate the number of unique customers served for the year.

participation rates begin in 2017 and extend through the last year of the proposed three-year plan (in this case, 2023).

7.4. Example Results

The utilities did not include the results of the participation analysis in their April 1, 2020 draft plans. Therefore, we cannot provide results based on the latest expectations for efficiency programs in New Hampshire.

We worked with the utilities to gather participation information, but the utilities were unable to provide all required data at the time we drafted the participation model.[36] Where the utilities were unable to provide data, we used reasonable assumptions based on efficiency data in the 2020 update to the 2018–2020 plan and the rate and bill impact analysis. We held this data constant for each year and reporting period as placeholder assumptions to build the participation model and estimate theoretical results. Below, we provide illustrative participation results using these placeholder values.

Figure 4 illustrates the sector-level participation results, using Eversource's electric electric's C&I programs as an example. Although we use placeholder values, in theory, the 2017–2019 data should reflect actual participants, the 2020 data should be consistent with the 2020 update to the 2018–2020 plan, and the 2021–2023 data should be consistent with proposed participants for the new three-year plan.

Figure 4 below hypothetically illustrates that, by the end of 2023, about one-third of Eversource's eligible customers will have participated in efficiency programs. This is the portion of customers that will have experienced bill reductions instead of bill increases.

[36] Liberty provided planned 2018 data, Unitil provided planned and actual data for 2017 and 2018, and Eversource was still gathering participant data.

Figure 4. C&I annual and cumulative participation

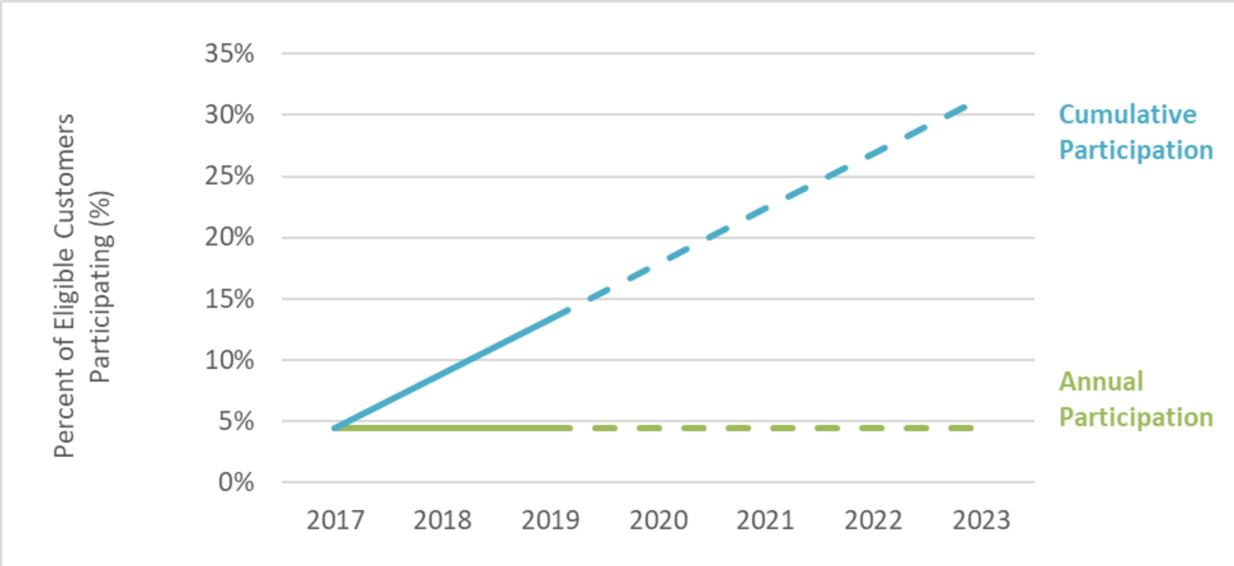


Figure 5. Sample Program Annual and Cumulative Participants

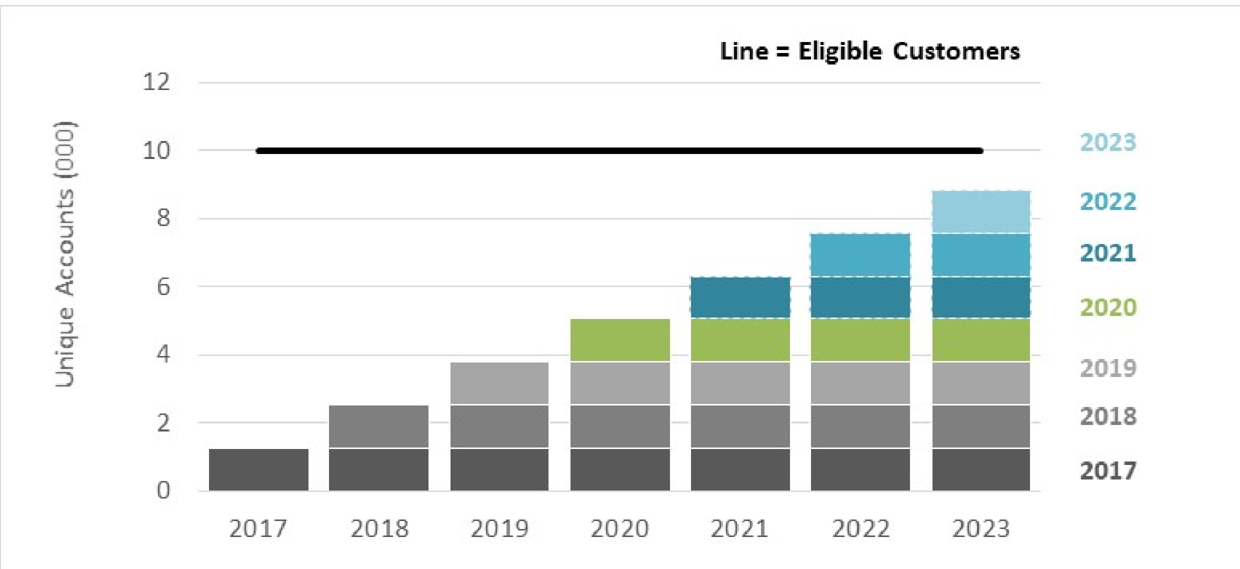
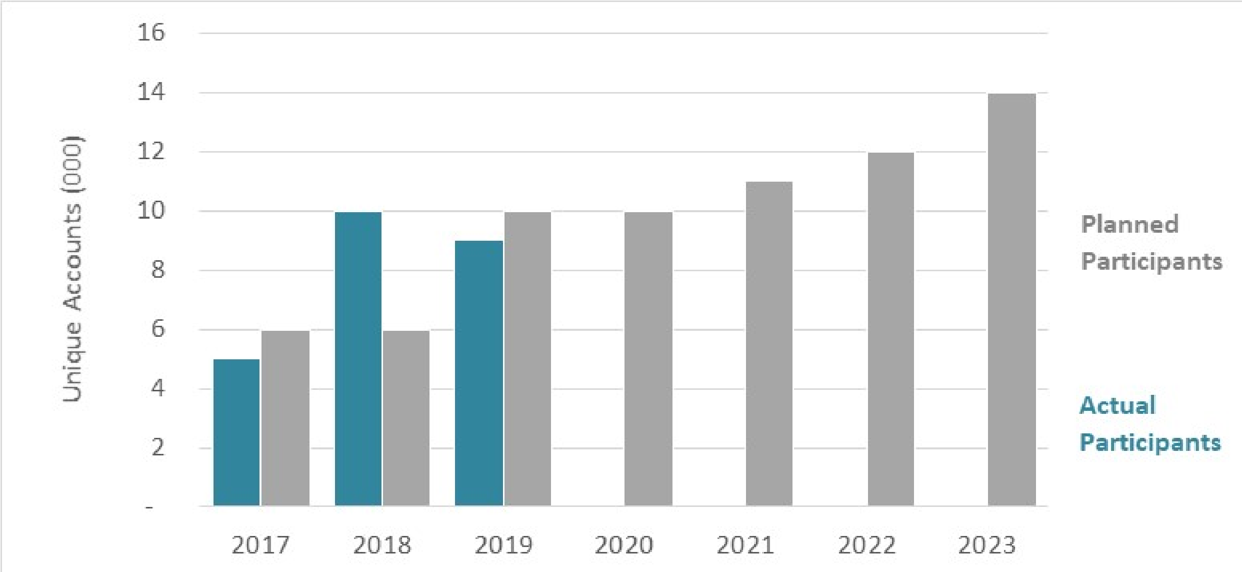


Figure 5 shows how many customers (defined for this program as unique accounts) participated in a hypothetical program in each year the program was offered and cumulatively over time. The horizonal line represents the total number of eligible customers that can participate in the program (in this sample 10,000). Depending on the program eligible customers could mean all residential customers, businesses below a certain annual usage, etc. This figure allows a utility to easily visualize the remaining potential for new participation within a program.

The participation model provides other participation results that may be of interest to stakeholders, including planned compared to actual participation rates as shown in Figure 6.

Figure 6. Actual versus planned participation



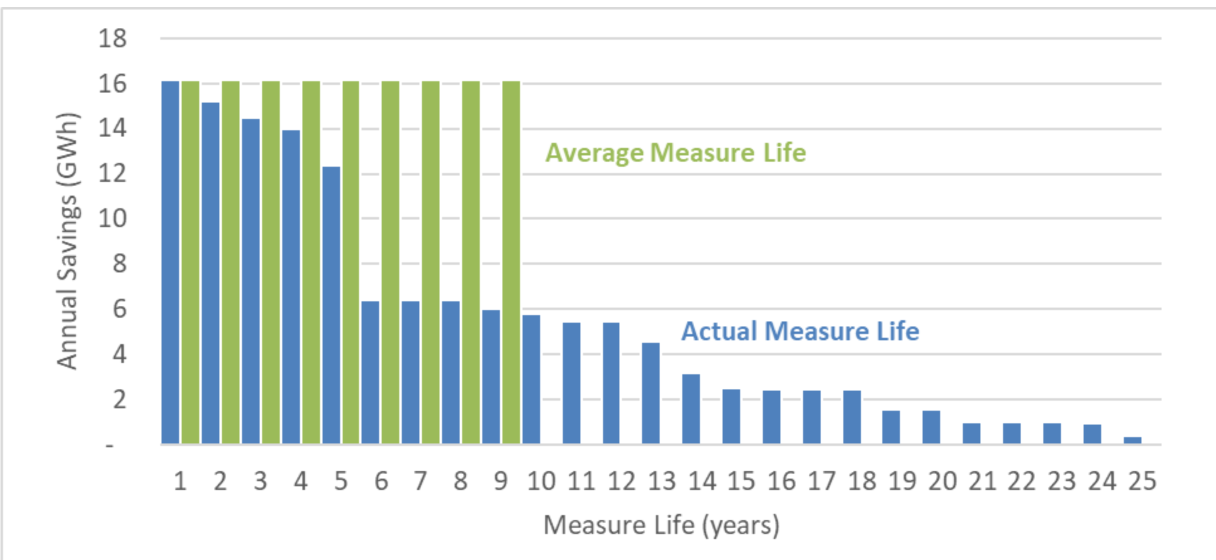
Appendix A. LONG-TERM STUDY PERIOD

The RBI model includes several simplifying assumptions to allow for its use across the NH utilities and for the assessment of a three-year plan. One of the simplifications involves the use of a weighted-average measure life and a long-term study period.

The weighted average measure life is used in the model to estimate the length of time that benefits and lost revenue will impact each rate class from the installation of energy efficiency measures due to the three-year plan.

The use of a weighted average measure life in the model results in an assumption that all the energy savings will expire at the end of the average measure life. This condenses the savings period and assumes all savings occur within that weighted average at the level equal to the savings in the first year. However, in reality, each energy efficiency measure has a different measure life, and savings will gradually dissipate over an extended period. The difference is shown in Figure 7 below.[37]

Figure 7. Annual savings using an average measure life or actual measure life distribution



While the model required a simplified approach to calculating the measure life, it is important to still account for the fact that, in reality, certain measures will still be producing energy savings and impacting rates and bills over their longer-term lifetime. For example, the NH efficiency plans include several

[37] To develop this figure, we used Eversource's residential savings from its 2020 plan update. We provide this figure to illustrate the difference in measure life calculations and its inclusion should not be a reflection on Eversource's savings data.

programs with measures that continue to provide savings out to 25 years—such as those included in the HVAC and EnergyStar Homes programs. In order to account to measures that extend beyond the average measure life of the efficiency program portfolio, we use 25 years as the study period for each individual year, which results in a 27-year study period for the three-year plan term. The long-term rate and bill impacts are determined by taking the levelized value over the study period.

Levelizing these impacts over a 25-year period provides for more accurate results than if the impacts were assessed just over the weighted average measure life.

To highlight the accuracy of this approach, Table 2 below shows a stream of energy savings from a hypothetical efficiency program with an average measure life of 10 years. It highlights the difference in assessing impacts using the actual distribution of measure lives over time compared to using the weighted average approach.

The Actual Distribution column shows a stream of annual energy savings from Years 1 through 25, declining over time based on the actual measure life distribution over time. Whereas, the weighted average column shows annual savings impacts assuming 100 percent outputs through the first 10 years and zero in later years (which is the method used in the RBP model).

Table 2. Comparison of actual measure life distribution to the weighted average approach

Year	Actual Distribution	Weighted Average
1	100	100
2	95	100
3	95	100
4	95	100
5	95	100
6	90	100
7	90	100
8	50	100
9	50	100
10	25	100
11	25	0
12	25	0
13	25	0
14	25	0
15	15	0
16	15	0
17	15	0
18	15	0
19	10	0
20	10	0
21	10	0
22	10	0
23	5	0
24	5	0
25	5	0
Total	1000	1000
Measure life (years)	10	10
Levelized average over 10 years @1.5% discount rate	83	105
Levelized average over 25 years @1.5% discount rate	50	51

As the results show, when using the average measure life instead of the actual measure life distribution, the use of a longer-term study period enables more accurate results.

When levelized over the 10-year average measure life, the resulting value of 105 in the weighted average column ends up being much higher than the value we would expect if we used the actual distribution of measure lives over the course of 25 years (a value of 83). This approach overestimates the annual average savings impacts.

When the same method is applied for a 25-year period, the result of the weighted average is much closer to that of the actual measure life distribution (51 compared to 50).

As this example shows, the simplified approach provides an appropriate level of precision to fulfil the key purpose of the model, which is to provide an approximate indication of the rate and bill impacts that will occur over the long term from the implementation of an energy efficiency plan. This is especially true given the fact this model was built to assess the long-term rate and bill impacts at the sector level and not the program level.

While the model's approach is appropriate for assessing the long-term impacts of a three-year efficiency plan, the results of this analysis are not intended to replace or replicate the detailed analyses utilities undertake when calculating rates for efficiency cost recovery through the SBC for electric utilities or the LDAC for gas utilities.

NHSaves
Your Source for Energy Efficiency

January 2020

NHSaves: External Funding and Partnership Assessment

Prepared for
NHSaves
(partner utilities: Eversource , Liberty, Unitil, NHEC)

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Table Contents

1. Executive Summary

The original directive for this project, provided by NHSaves to the Consultants, was to identify additional sources of funding to support the consortium's energy efficiency and weatherization programs (commercial and residential). Upon further discussion among the team (representatives of the four partner utilities - Eversource, Liberty Electric, NHEC, Unitil Electric; Resilient Buildings Group and Rome Specialties, Inc.), and other stakeholders, several **key investigative-questions** emerged which have helped to provide context, structure and nuance to this research:

1. Is external funding available to expand NHSaves?
    a. What untapped private and/or public foundation resources (if any) are potentially available to NHSaves or affiliated nonprofit partners?
    b. What untapped federal and/or state resources (if any) are potentially available to NHSaves or affiliated nonprofit partners?
2. How can the impact (measured by number of people positively affected) of NHSaves programming be improved through the creation of new partnerships and/or enhancement of existing partnerships?
3. In what ways could NHSaves processes be adapted to improve efficiency and effectiveness?

The precise wording of these questions is intended to suggest that viable strategies which could improve the quality of life of NH residents, without increasing NHSaves expenditures (though not necessarily by reducing expenditures), may be feasible. The team concurred on this point and it has thus been incorporated into the scope of the Consultants' investigation. NHSaves representatives also expressed their interest in seeking grant opportunities that would directly benefit nonprofit partners (and in fact these organizations would likely serve as the applicants of any grant submissions). This tactic is informed largely by the reality that most grantors, especially on the private side, would be reluctant to award funds to a consortium of utility companies with a $65 million program budget.

The pursuit of answers to these questions led to a two-phase investigative approach, aimed at ensuring that all possibilities - funding opportunities, partnership opportunities and quality-improvement ideas - were robustly explored. *Phase 1* involved a comprehensive search for public and private foundations that: (1) have an interest in several key fields, individually or in various combinations: energy efficiency, public health, and affordable housing, and (2) which fund programs in the state of New Hampshire. Research methods are described below. *Phase 2* was more qualitative in nature, aimed at understanding the current work of NHSaves' existing collaborators/affinity-organizations, the synergies between NHSaves and these organizations, and the ways in which these relationships could potentially be improved to achieve greater impact.

This process, outlined below with supporting documentation included in the Appendix, has yielded important insights:

- NH-based foundations hold the most potential for external funding and **local non-profits are best-positioned** to identify and seek specific funding opportunities
- Community Action Agencies (CCA), largely responsible for implementing residential weatherization programs, are hampered by a **shortage of contractors**, and by cash-flow issues
- There is interest in **re-establishing the "One-Touch"** assessment tool/collaboration process, and a broad array of stakeholders are interested in **improving collaboration** as a means to amplify impact to NH residents

- Other institutional stakeholders (Department of Health and Human Services (DHHS), NH Housing Finance Authority (NHHFA)) are particularly interested in the connection between weatherization and public health. These organizations currently tap into weatherization program funding and have suggested that implementation-efficiency and outreach could improve with budgeting, and a streamlined administrative process.

The concrete recommendations provided at the end of each section of this document - organized as "Phase 1" and "Phase 2" - were derived based on the insights gained through stakeholder-interviews and funding-research, and are framed by the key questions outlined above. Which, if any, of these recommendations NHSaves decides to implement will be based largely on the 'global' strategy which the consortium decides to pursue. Based on the findings outlined in the pages that follow, the consultants have identified four viable ***strategic directions***.

Strategy 1 - Do nothing. A legitimate decision would be for NHSaves to acknowledge the difficulty in winning outside funding, and the effort and cost that would be involved in developing new programming solely for this purpose. The content of this report clearly articulates the challenges involved in such a strategy; and while winning foundation or government grants with the help of non-profits is feasible, it would require great effort with a high-degree uncertainty in regard to return on investment (ROI).

Strategy 2 - Aggressively seek foundation funding. Rather than proposing that NHSaves or the consultants lead the process of developing programming and seeking grant funding, it would be more realistic to embrace a decentralized approach. If non-profit partners express an interest in applying for new funding related to weatherization/efficiency, it is most appropriate - and chances of success are better - to allow them to take the lead. If they are successful in winning new grants and achieve measurable results that align with NHSaves goals, then NHSaves can take credit. Consider allocating remaining funds from this contract (possibly through a subcontractor-relationship with RBG) for this purpose. Note, this strategy could be implemented in parallel with *strategy 3* or *strategy 4*.

Strategy 3 - Ad hoc operational improvements. Some of the recommendations, if adopted by key decision makers, can be implemented with minimal effort. For instance, by improving coordination with the USDA regional office (VT) and communication between NHSaves and business/agricultural consumers whose interests overlap the two agencies, an additional $200,000 or more could be directed toward efficiency projects in NH (see pg. 9). Further, public and non-profit stakeholders (CAAs, NHHFA) have indicated that the impact of their work (i.e. number and value of projects completed) could grow if operational policies & procedures (i.e. budgeting, payment processing) were modified/improved. NHHFA also indicated they possess approximately $1 million which could possibly be directed toward NHSaves programming (more dialog needed). Other such improvements are also possible.

Strategy 4 - Pursue recommendations in a holistic/strategic manner. There are some big cross-sector issues 'in-play' within the space which NHSaves operates. The NHSaves program impacts - and is impacted by - public health, workforce development and economic development/poverty alleviation. Based on feedback from key players that operate in these sectors, there is high-interest in better collaboration as a means to ultimately improve the quality of life among NH residents and businesses. The workforce issues (i.e. shortage of auditors and contractors) affects the number of projects which CAAs and other agencies can complete each year; weatherization of a home, combined with a childhood asthma prevention project, could lead to fewer emergency-room visits; a resuscitated, electronic-version of "One-Touch" could help multiple agencies including NHSaves to better prioritize where its money is spent; goals set jointly by NHSaves and NHHFA could lead to completion of more *large* projects and thus impact more people/$-spent; etc. Yet, despite these and other overlapping interests, there is a lack of formal systems that could potentially enhance communication, coordination, and ROI among key public, private and quasi-public organizations. To address these issues in a holistic/strategic way would likely require a 6-12+ month strategic planning process.

2. Phase 1 - foundation research

The goal of the research was to identify funding opportunities which align with the NHSaves weatherization/energy efficiency programs, as well as health related-programs operated by NHSaves' implementation partners.

Given that NHSaves is a large organization (with a large budget) and that applying for new funding will require planning and coordination with nonprofit partners, raising funds through institutional grants (i.e. foundations, government) should be viewed as a long-term process. For NHSaves and/or its partners to be well-positioned to compete for grant funding, several important factors should be considered: (1) The applicant and program for which funding will be applied should be clear - developing a new program for the sole purpose of seeking funds is not a prudent strategy. Doing so would require a significant allocation of time and staff-resources by the nonprofit(s) for a highly-uncertain result. (2) Funding should be sought for existing programs which could benefit from additional funds, or new programming, only if funding opportunities squarely-align with the mission and strategic plan of the applicant organization. (3) The cost-benefit of applying for funding should be considered, as the chances of winning any individual grant is generally low and the time-commitment can be great.

NHSaves is in a unique situation, in its context and ability to raise funds. Consider a few pros & cons of seeking grants, with and without partners.

Table 1. Advantages/disadvantages of NHSaves vs. partner organization serving as applicant

Applicant = NHSaves		Applicant = NHSaves Partner (i.e. CAAs)	
+	-	+	-
• Strong infrastructure • Successful track record in weatherization • 'Brand awareness' • Could leverage existing partnerships, should a suitable funding opportunity be identified, to strengthen application • Availability of matching funds	• Difficult to demonstrate financial need with a $65m budget • Slow decision-making process • No direct connection to a discrete population • Sole focus is on weatherization/ efficiency programs	• Strong connection to communities-in-need • Breadth of programming that extends beyond weatherization into sectors including health, housing, basic needs, etc. • Ability to track and demonstrate outcomes • Existing relationships with funders • More nimble • Availability of matching funds	• Partners have other priorities and may not be interested in pursuing this strategy • There are limited # of foundations in NH and partners may be reluctant to create competition for their other programs • NHSaves would lose some control over the process

2.1. Research Process

In researching potential foundation funders, two platforms were utilized: (1) Foundation Center Online - by far the most-used research tool in the industry - and (2) Instrumentl - a newer platform that follows a different algorithm and thus often yields results not identified by the first.

Four primary sectors were researched, as searching 'weatherization' alone would be too limiting: (1) Weatherization, (2) Health, (3) Public health, (4) Renewable energy (commercial side) - more macro in scope and systemic - opportunities for policy, new programs in CHG reductions, transportation/EVs, etc. To limit the possibility that viable, potential, sources were not overlooked, several query-permutations were performed under each category. Key search-criteria included: target population (i.e. low income, moderate income, refugees/vulnerable communities), geography (i.e. all of NH vs. certain counties/regions), grant size, and various combinations of the 4 sectors mentioned above.

Once a broad list of possible funding sources was identified, the next step was to assess which grantmakers, on paper, seem to be a good fit. This was accomplished by examining funding history (including 990-tax returns in some cases) stated programmatic priorities, and total assets/total giving/total category giving/type of giving (i.e. capital, vs. program, vs. unrestricted/operational). A comprehensive 'reverse-search' was also performed to identify which foundations have historically supported related-organizations such as CAAs and others that search basic needs/health needs of NH residents, and work in the health and/or energy-efficiency/conservation space.

Since New Hampshire is a small state, there are fewer foundations based here (or even which are based elsewhere but fund programs in NH) than larger states such as Massachusetts, Connecticut, New York, etc. Because the number of prospective foundations is relatively small, a 'broad net' was cast to help ensure that every prospect was examined.

2.2. Research Results

My initial search resulted in 72 prospects. To refine this list, I reviewed the basic guidelines and websites of each foundation, where applicable, to weed out foundations that were clearly not a good fit. Also, as mentioned, I reviewed the public 990 filings and other documentation for those which showed promise to better understand the types of organizations they support based on funding history. This knocked out many funders that were irrelevant or had a very distant chance of shared priorities, or whom are not currently accepting unsolicited proposals.

I assigned all foundations a ranking, which resulted in a list of 14 that are worth pursuing (ranked 6+) - but only if the right strategy/program can be developed. There were another 11 that fell in a middle ground (Rank of 5) - not a strong connection, but nothing to preclude an appropriate partner from applying should time/interest and resources allow. I do not recommend applying to any of these foundations at this time. Before doing so, it is important to define a winning strategy for how to use each foundation's precious dollars. Unfortunately, there is probably not a single program, target demographic or geographic-focus that will appeal to every foundation on the list. The implication: a distinct approach is needed for each foundation. Some foundations only fund programs in Northern NH, some are only interested in health, some are concerned only with environmental impact. It is for this reason my primary recommendation regarding seeking foundation funding is to follow the lead of NHSaves' community-based partners (most likely CAAs).

2.3. Foundation Strategy

Seeking funding through grants is an important element of any fundraising strategy and the key to success is cultivating relationships with these funders - sometimes this can be done before submitting the first grant. Or, it may take two or three attempts before winning the first grant from a particular funder - through this process, the funders will get to know the applicant. And even if turned-down the first time, valuable feedback will be received, and relationships that can leverage the next time around will be developed. This is especially true of new funders, which is why **calling each funder, personally, is recommended even before even sending an.** It is more appropriate for non-profit partners to make first contact; the consultant can coach them on how to approach these foundations. The giving range for each funder - based on past grants - is provided in the appendix. Some foundations give grants that are quite large; keep in mind, however, that the largest grants tend to go to those organizations with which the foundation has an established relationship/has funded in the past. Some foundations give grants in the range of only $10,000-$20,000; based on ROI, the effort in applying for smaller grants may not be justified, given that the probability of winning any one particular grant is generally low.

When reaching out to funders - either on the phone or via LOIs - it is important to understand in advance what their interests are. If a funder does not fund capital projects, perhaps ask for funds for training contractors (for example). For foundations that *only* fund capital projects and for those which give large grants which are easier to justify via a capital request, perhaps seek funding for upgrades to a public housing development (for example) in that foundation's targeted geographic area. Also, the giving range must be always considered in aligning a request with a particular funder - the amount of the request should be based on their historical giving and/or the size of their foundation. If asking for $100k from a foundation that only grants $20k per year, even if the fit is great, that is a non-starter.

A few other key considerations, when seeking, or considering whether to seek foundation grants:

- Funders often want to be the "last-in." Meaning they want their dollars to complete the fundraising goal. They do NOT (generally) want to make a contribution to a capital campaign that may take months or years to complete. If asking a foundation for $50k, then the balance of funds needed to complete the project should already be available (This is not a hard-and-fast rule, but for the most part, this is what can be expected). In this regard NHSaves and/or its non-profit partners are well-positioned since matching funds are likely readily available for weatherization projects.
- Funders are more willing to give a grant if the organization can demonstrate broad community support. In this regard a NHSaves-CAA (or other partner) would be well-positioned based on strong grass-roots track record of CAAs helping to meet the basic needs of the community.
- Funders do not like uncertainty; this means that without a clear path to the fundraising goal, and a clearly-defined project, receiving the grant is unlikely.
- Most funders require their grant funds be spent within 12 months of the award.
- Foundations LOVE matches! Some may offer a matching or challenge grant (i.e. give a commitment of $xx,xxx if the applicant raises $xx,xxx by a certain date). Keep in mind, every foundation is different and there is no way to know how they may or may not be willing to engage until dialog is initiated; as noted earlier, this dialog is best facilitated by NP partners that enjoy an existing relationship with the funder.

Recommendations - foundation grants

1. **NHSaves should <u>not</u> serve as an applicant** for the reasons highlighted in Table 1.
2. **Non profit partners will have the best chance of winning** grant awards from NH-based foundations and thus should serve as point. Let those partners who have an established track record of effectively working with NHSaves to determine which, if any, foundations to approach to support programming that includes (or could include) a weatherization program. **Research contained in this report**'s appendix (details about foundations' fields of interest, deadlines, application requirements, typical grant sizes, etc.) **can be shared as a resource**.
3. **Subsidize grant-writing costs** associated with program-planning and the preparation of applications, that would be incurred by NP partners. Establish a clear criterion (i.e. connection to weatherization/efficiency/health outcomes) that needs to be met for the NPs to qualify for this subsidization.
4. Should NHSaves be amenable to #3, above, **remaining funds** that have been committed to the consultant(s) (in accordance with signed contracts/sub-contracts) **could potentially be utilized**, as a substantial balance exists.

5. Encourage NP partners to reflect on **ways that NHSaves funding could be leveraged**, and additional funds could be used, to add value to *existing* community-based programs which are focused on outcomes focused on health/public health and poverty-alleviation.

3. Phase 2 - Stakeholder research

Several NHSaves stakeholders and partners were interviewed to gain insight into the program's benefits, and to explore possible new collaborative approaches that could improve impact and partner-implementation of NHSaves programming. Below is a summary of conversations between the consultant and representatives of partner/affinity organizations, followed by recommendations that were derived based on these conversations.

3.1. Southern New Hampshire Services (SNHS)(Ryan Clouthier, Deputy Director). In 2019 SNHS completed approximately 700 weatherization projects for low-income households. The majority of funding for these projects was provided by NHSaves, with the balance of resources provided through the federal Weatherization Assistance Program (WAP) funded by the US Department of Energy and other programs administered by the NH Office of Strategic Initiatives. Approximately one-third of the income-eligible households served by SNHS request weatherization services each year, of which approximately 50% qualify, based on an energy audit.

However, there is currently (and has been for several years) a shortage of qualified contractors available and willing to conduct weatherization work; the waitlist - based on the number of qualifying households - is approximately 3-4 years, a constraint influenced by the limited number of certified-energy auditors). Even if there were enough auditors and contractors to complete the needed work, funds would be insufficient. Ryan suggested improvements to the administration of the weatherization program - that would improve effectiveness of SNHS' role. These include: (1) Establish a budget so SNHS can better plan. The budget could be based on the CCA's previous year's expenditures and types of weatherizations performed - essentially NHSaves would be guaranteeing a minimum level of Weatherization Program funding. (2) Provide a cash-advance based on prior-year performance which can be drawn-down as weatherization jobs are completed - this will help SNHS to perform its work more effectively and better recruit, train and retain contractors and auditors.

Ryan was involved with "OneTouch" and felt it was a strong program that should have been continued; he sees a continued need for it today, especially in the context of the state's focus on "Whole Family Health." OneTouch, he said, was very labor intensive and was in the process of being systematized electronically before it was discontinued. He feels the utilities are generally focused on the energy-efficiency benefits of weatherization, and that a greater focus on the health benefits is also warranted.

3.2. New Hampshire Housing Finance Authority (Chris Miller, Senior Director of Strategic Initiatives). NHHFA's portfolio includes 400 affordable housing projects, big and small, across the state. The organization is currently undergoing a benchmarking process to inventory the condition of its assets, including the need for general and energy-efficiency-related upgrades. To date they have completed about 100 'benchmarks.' This process is in-alignment with NHHFA's strategic plan, and a means to help the organization better manage its assets. NHHFA believes it can increase the impact of NHSaves resources, through improved administration of and access to this funding, by focusing resources on benchmarked-properties. A set budget for the year, for instance, would allow the organization to better plan-out its projects and know with certainty which projects it could fund and thus complete them in a timelier basis. Because a weatherization project in an affordable housing development could impact anywhere from 1 to 100 families, the impact of NHSaves funding in these settings is multiplied (compared to single- or even multi-family household).

Another benefit of establishing a budgeting process would be that, for new construction and/or purchase/conversion (to 'low-income') of existing properties, NHHFA could leverage NHSaves funding to help the buyer qualify for and secure financing. Currently, NHSaves funding is applied for after the closing, on an "opportunistic basis" (Chris Miller), largely with the guidance of Resilient Builders Group (RBG); RBG often presents NHHFA with funding opportunities as they arise and/or they are made aware of them. According to Miller, there are a number of variables that create difficulties in accessing NHSaves funds: they are not aware of what funds are available and the timing in which those funds are available, and they do not have a systematized approach to mapping projects with those funds (this deficiency is a 'chicken-egg' scenario - NHHFA does not have a process because they do not know which/when NHSaves funds will be available).

On December 5, 2019 the consultant (Dana Nute) facilitated a "Lunch and Learn" event at NHHFA; in attendance were 8 NHSaves Program Managers, 8 NHHFA employees, and 14 Developers of low-income housing. There appears to be interest on the part of NHHFA in exploring richer collaboration with NHSaves.

3.3. Office of Strategic Initiatives (OSI) (Kirk Stone, Weatherization Assistance Program Manager). Stone overees a $1.5m budget sourced from the Department of Energy (federal) that is exclusively for use by low-income (<200% poverty level) households. OSI funds are distributed through CAAs, as they are for NHSaves funding. He concurs with Ryan Clouthier of SNHS that there is a significant shortage of contractors (qualified) and auditors and feels that, to expand and/or improve the program in any meaningful way, this issue must be addressed. Stone suggested that perhaps there is a need to raise wages/payment structure for weatherization work.

Stone is familiar with One-Touch and thinks it was a valuable initiative; his assessment on *why it failed* is essentially that funding was not available to cover the extra time it took to conduct the surveys, manage the data, etc.; generally, he was a fan and would like to see it re-initiated. Other stakeholders were of the opinion that, while useful, One-Touch needed to be better integrated, electronically, across agencies (state and non-profit). He also mentioned a program in DHHS funded by the CDC for Asthma (Asthma Collaborative) which recently won a $5 million federal grant to reduce childhood asthma; one component of program involves raising awareness among families of weatherization program.

3.4. Division of Public Health Services, Healthy Homes & Environment Section (Beverly Drouin, Section Administrator). Drouin indicated she has had extensive interaction with NHSaves weatherization program in the past, primarily in a coordination-capacity. She and her team - in around 2010 - developed "One-Touch" - an innovate means to improve the efficiency of and coordination between state and quasi-state agencies, community-based partners, and NHSaves. Partners included: (1) the lead abatement program (DHHS); (2) Maternal and child health program (DHHS); (3) NHSaves weatherization program; (4) housing programs (NHHFA), and; (5) the Department of Energy's LIHEAP and WAP. The 29-question survey-tool, designed to determine whether residents who were receiving a visit from one of the partner were in need of services from any other partners, was used from extensively from around 2010-2015.

According to Drouin - one of the founders of One-Touch - the principal behind the tool was that families being served by one of these agencies often have multiple, and possibly complex, overlapping needs. One-Touch was designed with the premise that one of the hardest aspects of provisioning services to those in need is gaining 'access.' Therefore, if one of these partners was already in a home, that family could receive a greater benefit if - during that visit - the family's broader needs were assessed and then followed-up upon. While One-Touch was in-use, during the course of their visit with a family, the initial service provider would complete the survey - with the answer to each question ultimately lead to referral (if necessary). For example, during a weatherization visit it may have been apparent from the survey that the mother and child needed nutrition assistance, or asthma mitigation education (i.e. inside smoking), etc.

For several years One-Touch was used in paper-only format. Later, the survey was switched to Surveymonkey and was completed via tablet. Providers agreed that One-Touch was leading to more efficient and better-targeted/more impactful services. However, in around 2015 the program faltered, partly due to technical challenges and partly due to staffing changes. Outcomes of the program are documented in a report of a pilot study that took place in Manchester. Could/should One-Touch, or this type of coordination, be reinstated?

3.5. Division of Public Health Services, Asthma Control Program (Keri Brand, Asthma Control Program Health Promotion Advisor). Brand and one other individual coordinate the newly-funded Asthma Prevention program, through a CDC grant. Part of their plan is to promote weatherization and Brand indicated they are interested in studying the impact of weatherization on health. She is not familiar with the way which NHSaves operates and is unsure of how she can/should coordinate/interface with the program. She is, however, interested in doing so. Their program will include home visits and trying to make connections with stakeholders including pediatricians, school nurses, etc. in order to better educate the public about asthma prevention. She envisions coordinating with CAAs and possibly outsourcing energy audits, and implementation, to the CAAs.

3.6 USDA Regional Office, Montpelier, VT (Ken Yearmin, Rural Development Specialist). The USDA's Rural Development program offers grants for renewable energy and energy-efficiency projects through the Rural Energy for America Project (REAP). Through this program - for which the annual budget is about $500,000 - businesses and agricultural producers located in counties designated as "rural" by the USDA may win grants equivalent of up to 25% of the value of the entire project. According to Yearmin, typically, the split between projects which are classified as renewable vs. efficiency is about 90/10. Grants are very competitive. Yearmin indicated that he would like to see more of a balance and noted that efficiency projects typically score higher than renewables, partly due to a faster pay-back period. Were the USDA to receive more applications from NH there is a strong likelihood that funding designated for energy-efficiency projects would increase substantially. This presents an opportunity for NHSaves.

3.7. New Hampshire Community Development Finance Authority (CDFA) (Katherine Easterly Martey, Executive Director). RBG met with a CDFA representative in January - this organization is very interested in learning more about how they can potentially use their funds as match, which would be beneficial to them. Funds currently available to the CDFA, via the *Clean Energy Fund*, include: the Municipal Energy Reduction Fund, Better Buildings, Enterprise Energy Fund, Community Development Block Grants, CDBG Economic Development Grants. CDFA seems to be well-positioned to serve as a fiscal agent for NHSaves programs. Currently, they are not staffed to manage the field aspect of the programs but would be willing to explore this possibility depending on the amount of funding and length of time of this initiative. Overall, CDFA seems to be the most viable, prospective partner.

Recommendations - partner engagement

1. **Create a budget** for CAAs and NHHFA.
    a. CAA's - Consider establishing a budget so SNHS and other CAAs can better plan. The budget could be based on the CACA's previous year's expenditures and types of weatherizations performed - essentially NHSaves would be guaranteeing a minimum level of Weatherization Program funding. Consider, also, providing a cash-advance based on prior-year performance which can be drawn-down as weatherization jobs are completed - this will help SNHS to perform its work more effectively and better recruit, train and retain contractors and auditors.
    b. NHHFA - focus on the "benchmarked" projects and map NHSaves $ to those projects, along with a timeline. Consider linkage with health-outreach programming. Could potentially leverage non-weatherization funding to achieve greater impact. Consider providing a budget to NHHFA for weatherization projects based on prior year NHSaves-

payments; this would help NHHFA to lock-in financing, and complete projects, more quickly.

2. **Promote USDA's REAP to eligible businesses/agricultural producers -** Were the USDA to receive more applications for energy-efficiency projects in NH, there is a strong possibility that the number of such projects completed in NH would increase. If the USDA were to achieve a more balanced number of applications (i.e. 50/50) the amount of funds spent on efficiency projects in NH could increase by ~$250,000/year. NHSaves may consider more formal strategies to communicate this opportunity appropriate stakeholders. In theory - though would be difficult to measure - these funds could offset NHSaves resources.
3. **Enhance contractor and energy-auditor outreach**, training and incentives. There is a systemic shortage of both auditors and contractors willing and qualified to perform this work. This bottleneck is likely to persist - especially at times when the economy is strong - unless proactive steps are taken. Consider providing performance-incentives to both groups and/or increase in payment-structure.
4. **Consider setting aside carry-over funds** to use for initiatives which "improve capacity." Potential uses could include optimizing recruitment and/or training or contractors and auditors, program development, coordination (i.e. reviving OneTouch), etc.
5. **Encourage the PUC to include health outcomes** when measuring effectiveness of weatherization/efficiency programs/funding.
6. **Streamline processing and reimbursement** of weatherization/efficiency funding, which will in-turn help NP and other partners to complete more projects and to do so in a more time-efficient manner.
7. **Change perspective -** instead of looking for ways to bring more money into NHSaves programming, think about how this well-established program (NHSaves) can be leveraged to help partners to accomplish a greater volume and quality-of measurable outcomes for NH residents. This would require administrative changes that would bring more certainty and predictability. For example, if CAAs had a set budget to work with (perhaps based on prior year utilization of NHSaves resources) they could better plan. And if they were able to access some of that funding in-advance they would, for example, gain the ability to make improvements to program infrastructure such as contractor recruitment.
8. **Related to #7 - Consider undertaking a 6-12-month strategic planning process** focused on ways to improve outcomes through improved efficiencies and collaborations with existing non-profit, governmental and quasi-governmental agencies. Ultimately, there are more viable ways to improve outcomes through this course of action than by seeking external funding.

4. Non-profit partners (Lead: RBG)

Simultaneous to the foundation and stakeholder research, Resilient Buildings Group initiated the search for possible partnership(s) of non-profit organizations within New Hampshire to facilitate and manage current or additional programs through the NHSaves-branded Utility Programs. A table listing the non-profits that were contacted in late 2019 is included in Table 4 of the Appendix. This search is part of Task 2 as identified in the contract as shown in the following:

"Task 2 – Identify potential local non-profit partners *The Consultant will research and review potential local non-profit partners. Potential non-profit partners would have a goal or mission that has some alignment with the energy savings goals of the NH energy efficiency programs. Potential partners would need to have an interest in developing a partnership, in being the receiving organization for foundation* *funding and in implementing an initiative by paying funds to customers/contractors in conjunction with the NH Utilities.* **Deliverable:** Summary report listing potential partners and description of partnership areas of focus."

To date, of the 17 introduction letters sent (copy included in Appendix), 6 non-profits indicated they are 'not interested,' though they are supportive of the goals of this project. The other 11 expressed an interest and meetings between RBG and non-profit representatives have been scheduled for January and February to discuss potential collaboration. While some non-profits expressed an interest in meeting sooner, these meetings were deliberately scheduled for a time period after the presentation of this report, and strategic discussions to follow, to the NHSaves team. The partners which expressed an interested will be re-engaged once the NHSaves team decides on a strategic direction and/or provides RBG with a directive.

(1-4) Communication Action Agencies - For this analysis, four of the CAAs have been combined, they include: Southern NH Services, Belknap-Merrimack Community Action Agency, Community Action Partnership of Strafford County, and Southwestern Community Services. Each one of these organizations is interested in meeting and potentially becoming a partner for this initiative.

- **Plus –** These Agencies are already delivering the Home Energy Assistance (HEA) Program and have access to other funds such as Weatherization Assistance Program from DOE, LIHEAP funds which can be used for heating systems and additional funding for weatherization of homes. These programs are currently being implemented so they do not bring anything new to the initiative. Low- income clients are most likely the easiest target for foundation grants and state and federal funding.

- **Minus –** CAAs are currently "maxed out" on production and meeting the goals of the HEA Program. In 2019 RBG was asked by the utilities to assist in the HEA Program which resulted in RBG completing over 250 multifamily units; and RBG has already audited over 150 multifamily units for 2020 work. CAAs need to increase the workforce in both the in-house energy auditor category and implementation contractors. Some CAAs do not have the required financial strength to ramp-up to meet the current goals.

(5) New Hampshire Housing Finance Authority (NHHFA) – This quasi-state organization is recipient of federal section 8 vouchers and distributes throughout the state to Housing Authorities, eligible recipients and private landlords. They are HUD funded for the development of low-income tax credit developments. NHH became more aware of NHSaves programs after RBG sponsored a *Lunch and Learn* with 8 Utility Program Managers, 8 NHHFA employees and 14 Developers on December 5, 2019. NHHFA is more involved with the HEA Programs, Energy Star Homes, and Small Commercial Lighting. In the preliminary meetings RBG had it was apparent that NHHFA can bring much to the subject of funding as it pertains to their portfolio. **Chris Miller stated that NHHFA has a pot of funds in the vicinity of $1M dollars which they would be willing to use in support of NHSaves** Programs by funding measures that may require "pre-work" prior to completion. Examples include: installation of a new roof or repairs that may be required to install additional cellulose to an attic, wiring upgrades for either wall or attic installation.

- **Plus –** Fiscally a very strong organization with connections to government and private funding sources. Well connected with low income developers and clientele and directly involved with over 8,000 housing units (single and multifamily). Statewide in scope.

- **Minus –** Basically just interested and/or involved with low-income housing units, therefore associated with HEA Program. Other involvement is with Energy Star Homes and the Small Business Lighting Program. No desire to get involved with other commercial programs. No current staff available for oversight of NHSaves programs.

(6) Community Development Finance Authority (CDFA) – As described in section 3.6 (page 8), CDFA is a viable prospect and is interested in exploring additional partnership opportunities.

(11) Clean Energy NH (CENH) - This organization has been focused on public policy but within in the last year have expanded into the operational-realm by hiring a *Circuit Rider* that handles the 'North Country' and introduces municipalities to NHSaves programs and assists them in implementing energy audits and energy efficiency measures. CENH is expanding this mission with perhaps another Circuit Rider for other regions of the state and interested in talking further about this initiative.

(7) CATCH Neighborhood Housing – Most likely not a fit unless used as a funding pass through only. No current knowledge of NHSaves except for the HEA Programs and small commercial lighting in its multifamily units.

(8) New Hampshire Community Loan Fund - Most likely not a fit unless used as a fiscal agent only. No current knowledge of NHSaves except for the HEA Programs.

(9) Lakes Region Community College – Preliminary discussion pertained more to workforce development but interested in learning more.

(10) NH Residential Energy Performance Association – Strength is in the residential sector and they would be interested in this portion of oversight of financial and program implementation. I believe the current organization would have to be restructured in order to oversee any programs.

At this stage, gaining interest on the part of some potential partner organizations is challenging due to ambiguity in regard to expectations of them, details about the program, target demographic, potential funding (sources and amounts), and timing. And, as noted throughout this document, an issue which has consistently been raised by nearly all stakeholders relates to the current shortage in the labor market and the need for workforce development. This is an *extreme* issue on both the administration-side (auditing and oversight) and the implementation-side (contractors) which, in hindsight, should have been addressed 2 years ago. Additional funds, and creative programming, will be needed to increase the quality and volume of the workforce that is needed to accomplish the goals of current NHSaves programs.

Recommendations - potential non-profit partners

1. **Continue discussions with CDFA, NHHFA and CAAs -** CDFA may already have access to a 'pot' of funds which can be leveraged, and the CAAs already have a high-degree of familiarity with NHSaves programming. Continue a dialog with these organizations while reaching out to other potential partners as appropriate.

2. **Use NHSaves resources to assist with capacity building -** CAAs represent the most viable implementation partner for reaching underserved populations in NH, however they have limited resources, and experience operational-bottlenecks due to shortages in the labor market, as noted. Enabling true partnerships with these organizations will require some flexibility on the part of NHSaves. Consider: providing limited funds to assist CAAs so they can take the lead and pursue opportunities they perceive as viable, in identifying and applying for grants related to efficiency/weatherization; working together with the CAAs to recruit/train/hire new auditors and contractors; providing an annual budget to aid their planning.

5. Conclusion

As noted, this investigation was framed by three **key questions.** A synthesis of the analysis helps to directly and summatively address these questions.

(1) *Is external funding available to expand NHSaves (foundation, governmental)?*

The best strategy for attracting outside funding to support the goals of NHSaves, should the consortium elect to pursue this strategy, is to leverage NHSaves non-profit partners, and to allow them to take the lead. Foundations will be more receptive to this approach, and the community-based partners such as CAAs are best-positioned to target the programs/populations with the greatest need.

There are a handful of foundations in NH that would probably be receptive to an application from a CAA that had a dual focus on energy-efficiency/weatherization and health. Tillotson is the best opportunity and also gives the largest grants ($100,000+ possible). Many other foundations provide much smaller grants $5-$25k so the cost-benefit would need to be considered by the non-profit partner(s) before applying. Grants through the federal government may not be worth the effort, as these applications can be tedious and time-consuming to prepare, and would require programs in scope that extend far beyond simply weatherizing homes/businesses. The EPA's Healthy Communities Grant Program, for example, is a good fit but grants are only $25,000 and funding will be highly competitive. The EPA's Environmental Justice Collaborative Problem-Solving... grant, is also an option. This grant amount is much higher ($120k) and could be a fit with a program that linked community/public health and community organizing around environmental justice. This also would be a highly competitive grant which would require extensive planning/coordination to simply prepare an application. In addition, DOE has a Block Grant program, which provides resources to local and state governments, but most municipalities and the State of NH are probably already connected to these. The bottom line is that vetting, planning and applying for outside funding should be led by community-based (NPs or local governments) stakeholders. The best way for NHSaves to support these partners may be through counsel and funding to support the process.

(2) How can the impact (measured by number of people positively affected) of NHSaves programming be improved through the creation of new partnerships and/or enhancement of existing partnerships? **AND** (3) *In what ways could NHSaves processes be adapted to improve efficiency and effectiveness?*

NHSaves' programs and funding enables the CAAs, NHHFA and other partners to improve the comfort, health & wellbeing, and financial position of thousands of NH residents each year. Based on feedback from key partners, the impact of NHSaves' resources can be amplified - serving more NH residents, more efficiently - by improving administrative process. Specifically, better coordination in the form of joint-budgeting, streamlined reimbursement system, and advance-payments prior to the start of the program-fiscal year. These improvements would allow implementation-partners to reduce back-logs, potentially recruit and train more auditors and contractors, more quickly secure financing, and complete more projects in a shorter period of time. Some of the recommendations in this report are immediately-actionable; others will require varying degrees of planning if they are to be carried out in earnest.

6. Appendix

1. About the authors
2. Table 1. Foundation/gov't grant prospects organized ***by Rank***
3. Table 2. Foundation/gov't grant prospects organized ***by Date***
4. Table 3. non-profit partners by RBG
5. Copy of letter sent to non-profit partners by RBG

About the Authors

Aaron Rome is a strategic planning and grant writing professional, with 23 years of experience managing nonprofit organizations and developing/implementing winning organizational and development strategies. He has founded and managed two nonprofit organizations including one with a mission of improving urban education and 19 years ago launched an internet startup which he still operates today. His clients have included companies and non-profit organizations which operate in many sectors including: workforce development, mental health, higher education, public health, healthcare, medical research, environmental and historic preservation, the arts, economic development, housing, agriculture, human services, and more. He holds an MBA from Boston University and a B.S. in Civil Engineering from the University of Massachusetts. He has a successful track record of winning grants from private and public foundations and government agencies and has raised over $13 million for his clients over the past three years.

Dana Nute coordinates technical and construction measures for deep-energy retrofit and high-performance buildings and is majority owner of Resilient Buildings Group. He has been an intervener with the New Hampshire Public Utilities Commission on Energy Efficiency Programs, a member of the New Hampshire Climate Collaborative, and as a voting member of the Energy Efficiency and Sustainable Energy Board. He started Resilient Buildings Group after twelve years as the Director of Housing Rehabilitation and Energy Conservation for the Community Action Program Belknap-Merrimack Counties, Inc. Prior to his work with the CAPs, he managed and developed large commercial construction projects throughout the Northeast and overseas. He is a State-certified energy auditor with the New Hampshire Office of Energy and Planning, formerly on the Board of Directors of the Residential Energy Performance Association, on the Advisory Board for the State of New Hampshire Weatherization Assistance Program, a member of the Statewide Steering Committee for Healthy Homes, and a member of the National Weatherization Plus 2015 Committee in Washington, DC. Dana is serving his second appointment to the Advisory Board of the Residential Ratepayers for the Office of Consumer Advocate. Dana is a graduate of Northeastern University with a civil engineering degree working in construction management and development. He received the 2009 U.S. Department of Energy Management and Administration Award.

Table 1. Prospects organized by Rank

Rank	Grantmaker Name	About	Notes	Ask
9	Tillotson North Country Foundation, Inc.	They fund systems-change-level projects while, at the same time, supporting basic community needs. Priorities are broad; they state "Address gaps in basic needs for underserved, low-income residents."	Fund in Coös County, NH. Fund is taking a systemic approach to supporting two industries with significant potential for growth: Energy efficiency and non-motorized outdoor recreation (from hunting and fishing to hiking, biking and skiing). Strategy may be to partner with CAA(s), again focusing on health and economic benefits to improving energy efficiency for lower income and working class people. NPO would need to be applicant. Can request up to $100k for up to 3 years.	
8	EPA	The Environmental Justice Collaborative Problem-Solving (EJCPS) Cooperative Agreement Program provides funding to support community-based organizations in their efforts to collaborate and partner with local stakeholder groups (e.g., local businesses and industry, local government, medical service providers, and academia) as they develop and implement community-driven solutions that address environmental and/or public health issues for underserved communities. For purposes of this announcement, the term “underserved community” refers to a community with environmental justice concerns and/or vulnerable populations, including minority, low income, rural, tribal, indigenous, and homeless populations. Eligible projects must demonstrate use of the Environmental Justice Collaborative Problem-Solving Model to support their collaborative efforts during the project period. Applying organizations should have a direct connection to the underserved community impacted by the environmental harms and risks detailed in the workplan. The long-term goals of the EJCPS Program are to help build the capacity of communities with environmental justice concerns and to create self-sustaining, community-based partnerships that will continue to improve local environments in the future.	This EPA program seems like a good fit, if there were interest among the CAAs and/or other stakeholders. Perhaps do something in collaboration with the CDC/DHHS Asthma Collaborative.	
7	Norwin S. and Elizabeth N. Bean Foundation	The Norwin S. and Elizabeth N. Bean Foundation is a general purpose charitable foundation which awards grants in several relevant fields including human services, health and environment.	funds exclusively in Manchester and Amherst areas. Maybe partner with refugee resettlement agency or CAA to target underserved populations. Grants range from $3,000-$30,000	$20-$50k

7	New Hampshire Charitable Foundation	The foundation seeks to strengthen communities and inspire greater giving by: 1) investing charitable assets for today and tomorrow; 2) connecting donors with effective organizations, ideas and people; and 3) leading and collaborating on important public issues.	Has given many grants to NH organizations for energy efficiency projects including new construction, building upgrades, and generally to advance energy efficiency in NH. One of their statewide programs for helping peole in need is to close the gap for those with financial need. Could propose grant to create subsidy fund to help people afford weatherization. They also administer the Tillotson Fund - Large Grants Program. Contact after we having spoken to CAAs and other partners.	
7	Department of Energy - Conservation Block Grants	The program provides financial and technical assistance to assist State and local governments create and implement a variety of energy efficiency and conservation projects. The program's objectives are: To reduce fossil fuel emissions created as a result of activities within the jurisdictions of eligible entities; To reduce the total energy use of the eligible entities; and To improve energy efficiency in the transportation, building, and other sectors.	The program provides financial and technical assistance to assist State and local governments create and implement a variety of energy efficiency and conservation projects. The program's objectives are: To reduce fossil fuel emissions created as a result of activities within the jurisdictions of eligible entities; To reduce the total energy use of the eligible entities; and To improve energy efficiency in the transportation, building, and other sectors.	
6	New York Community Trust	Program goals: to mitigate climate change; make communities more resilient to climate change; protect public health from the hazards of toxic chemicals and pollutants; and preserve biological diversity. Within *climate change*, one priority is "promoting energy efficiency and alternative sources of energy for buildings... We encourage initiatives that cut across these program areas, especially those focused on smart growth, sustainable agriculture and regional food systems, and sustainable production.	Most of their programs are focused on NYC but environmental program funds orgs nationally. Note: "The Trust does not accept unsolicited proposals for the national and international environment program. To apply, submit a three-page Letter of Interest (LOI) and budget via the LOI portal that appears on our grant portal each fall (mid-September) and winter (late-February)." Given the size of this fund, assumption is that grants have potential to be quite large. (need to check 990). They have funded environmental programs in NH in the past.	$20-$100k
6	Barr Foundation	"While climate change is a global challenge, cities, states, and regions have become vital agents of leadership. We believe breakthroughs and progress will continue coming from the ground up and that Barr can help catalyze and advance solutions and leadership across our region in ways that also spur broader action. On occasion, we engage in targeted national or global efforts with significant opportunities to contribute to impact. Yet our principal geographic focus is the U.S. Northeast." Use and generation of energy is major focus in this area (in addition to transportation). "Our goal is to reduce the energy sector's emissions by building the path to a clean, efficient, and modern energy system."	Foundation is interested in scaling clean and smart energy in Northeast US. Within that priority "Accelerate uptake and innovation in comprehensive energy efficiency." Most grants go to NPOs with possibility to government agencies. Grants are large - median about $200k. Based on this statement, it is likely any request would need to be for system-level reform within the energy sector in NH: "accelerating a massive scale-up of renewables and energy efficiency across the Northeast; promoting efforts to make the grid smarter to enable that scaling up; and supporting learning networks that help cities and states get smarter about the most effective strategies from around the world. "	

6	Oak Foundation U.S.A.	In the Environment Programme we envision a world where our children will grow up in a clean, safe climate, our oceans are free of plastic, and endangered wildlife are protected from cruel and illegal trade. Within the energy efficiency and clean energy area they state: "To this end, we support organisations which: (1) partner with governments in their work to build a clean and safe energy future; (2) advocate for improved policies, financial support of clean energy projects and innovations that increase energy efficiency; (3) help integrate clean energy solutions into poverty-reduction programmes; and (4) support grassroots community-led campaigns."	6- Not a great fit. Only possibility would be apply for some type of partnership with one of the CAA's, for example, or doing something measurable with the DOE in NH or federal levels. Grants are fairly large. Median award in 2016 was about $200k.	
6	Endowment for Health, Inc.	The Endowment for Health is a statewide, private, nonprofit foundation dedicated to improving the health of New Hampshire's people, especially those who are vulnerable and underserved. We envision a culture that supports the physical, mental, and social wellbeing of all people -- through every stage of life. Priority to "Advance health equity for people who lack a fair opportunity to optimize their health potential for a variety of reasons including income, age, race, culture, ethnicity, disability, educational level, geography or sexual orientation." and they also like leveraged resources.	Health Equity is the area we would fall under. Funds exclusively in NH. Median grant is about $20k; some are in the $50-$100k range. Focus seems to be on communication/dissemination. Potential for a CAA to do educational/health outreach in conjunction with the energy efficiency awards... probably not enough $ to make an impact in terms of further subsidizing weatherization/efficiency projects. To be fundable any project woud have to be broad with a focus on capacity building and/or research and/or policy, I believe. Has given many grants for health programs in NH (Concord) including legal assistance org. and for ethnic and racial minority rights and healthcare access. Gives many grants to Foundation for Healthy Communities. Based on their focus on healthcare, may be a stretch. Look into "health equity" and "opportunity grants" programs.	
6	TD Charitable Foundation	The foundation supports organizations involved with affordable housing; education and financial literacy; and the environment. Special emphasis is directed toward programs designed to support low- to moderate-income individuals by providing services, training, or education that improves the quality of life and provides opportunities for advancement.	Decent opportunity for program that will help low income and moderate-income families ... leveraging NHSaves funding. Grants not huge.	$10-$20k
6	Jack and Dorothy Byrne Foundation, Inc.	Geography is of high importance.	Has funded many health programs in Northern NH.	$20k
6	Alexander Eastman Foundation	Awards grants to improve the quality and availability of health care and to promote good health and well-being for residents	Gives mostly to dental care and food banks. Funds only in Greater Derry (Derry, Londonderry, Windham, Chester, Hampstead and Sandown)	$10-$50k

6	Stantec Community Engagement Grant	Within their environmental priority: "Our support for the environment is focused on programs that promote sustainable development, environmental responsibility, energy efficiency, air quality, and climate change."	Funds in geographic areas near to company operations. In New Hampshire this includes: Hillsborough County, Rockingham County. Possible angle would be for local CAA or other NPO to apply and NHSaves provides matching support. Size of average grant is not clear, probably $5-$10k.	
6	Cogswell	Funds a wide variety of human service organizations in NH.	Exclusively supports orgs. in NH. Based on funding history may support initiative that benefits disadvantaged populations. Medan grant is about $10k. Has given up to $100k to housing organization and gives frequently to United Way. Partnership with CAA possibility.	
5	David and Lucile Packard Foundation	The foundation works on the issues its founders cared about most: improving the lives of children, enabling the creative pursuit of science, advancing reproductive health, and conserving and restoring the earth's natural systems. Climate: Reducing emissions that contribute to environment-damaging climate change;	Would need to have a project that was large in scope and not only direct-service to be of interest.	$50-100k
5	Agnes M. Lindsay Trust	Support for health and welfare, including services for the blind, deaf and learning disabled, the elderly, children's hospitals, children's homes, youth organizations, youth/family services and summer camperships/summer enrichment programs. The trust also supports colleges, universities, and private secondary schools through scholarship funds administered by the educational institutions to deserving students from rural communities.	Any request should focus on impact on children.	$5k
5	New Hampshire Children's Health Foundation	Giving primarily to: 1) increase access to children's health and dental insurance coverage; 2) promote oral health prevention for children through age five; 3) prevent childhood obesity with a focus on children through age five; 4) reduce and prevent childhood trauma; and 5) reduce food insecurity.	New priorities are "Prevent childhood obesity, promote oral health, Reduce food insecurity." Gives to Community Action programs. A stretch based on priorities. Would have to make the case that indirectly weatherization will improve child health or food insecurity by helping them keep more $ that would have gone to utilities. Not likely.	$20k+
5	John Merck Fund	The program seeks to improve the six-state region's air quality, build a clean energy economy, and reduce its greenhouse gas emissions by 20 percent within ten years and put the region on a trajectory to reduce emissions by 80 percent by 2050.	Has a strong interest in clean energy and efficiency but the efficiency piece is more focused on policy. Weatherization projects probably not of so much interest unless NPO were to seek funds for something such as advocating/lobbying for policy changes at the state level.	
5	Boston Foundation Inc	While they focus on Boston, they may have some funds that are directed for NH programs/energy efficiency. Need to contact to find out.	Requires follow to know if they have any relevant funds. Sent email inquiry to Ruth Cormier (ruth.cormier@tbf.org) on 10-30-19.	

5	Samuel P. Hunt Foundation	Not much info given	Funds mainly in Manchester area and has funded health centers	$10k
5	Mascoma Savings Bank Foundation	The foundation supports organizations involved with arts and culture, education, health, mental health, legal aid, hunger, sports, and human services.	Only funds in Central Western NH and up to $7,500.	$7,500
5	Weyerhaeuser Company Foundation	We support U.S. and Canadian communities where we have a significant presence or business interest. These communities range from rural to metropolitan, each with unique priorities and needs. Our employees serve on local advisory committees for our Giving Fund and develop funding priorities within four focus areas to support their particular communities. This provides a strong companywide framework for giving while allowing flexibility to meet unique needs in our different communities.	Foundation has priority areas in the areas of human services (affordable housing, environmental stewardship). Grants are probably small. Potential applicants are to contact a local office first.	
5	Bank of New Hampshire	Supports these counties in NH: Belknap County, Carroll County, Coos County, Grafton County, Hillsborough County, Merrimack County, Rockingham County, Strafford County, Sullivan.	Not clear that they have any real strategic focus. They give to many orgs, but not clear how much they give. Most likely the grants are small. Something that is human-services focused would have a chance.	
5	Environmental Protection Agency - Healthy Communities Grant Program	Grants are awarded to support projects that meet two criteria: 1) They must be located in and directly benefit one or more Target Investment Areas and 2) They must achieve measurable environmental and public health results in one or more of the Target Program Areas. Target Investment Areas and Target Program areas are identified in the annual competitive funding announcement. Funds for all projects should support activities to provide education, outreach, or training, in the Target Program Areas. The Regional Office will only accept submissions for projects that affect the States, Tribes, and Territories within the six New England States: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Projects that are National in scope are not eligible for funding under this Regional Program.	Program is focused in NE states with priorities: Clean, Green and Healthy Schools; Community and Water Infrastructure Resilience; Healthy Indoor Environments; and/or Healthy Outdoor Environments. Projects only $25k max!!	$25k

Table 2. Prospects organized by Date

Deadline	Rank	Grantmaker Name	Requirement	Ask
4/1/2019	**5**	Mascoma Savings Bank Foundation	Mail application	$7,500
1/16/2020	9	Tillotson North Country Foundation, Inc.	Concept paper	
2/20/2020	**8**	EPA Environmental Justice Collaborative Problem-Solving Cooperative Agreement Program	Application	$120,000
3/15/2020	5	Samuel P. Hunt Foundation	Application	$10k
8/31/2020	4	Institute of Electrical and Electronics Engineers	online application	
11/16, 2/15	4	New Hampshire Bar Foundation	Download application	$5k
August 2020	**5**	New Hampshire Children's Health Foundation	LOI	$20k+
Every 4 months	**7**	Norwin S. and Elizabeth N. Bean Foundation	Upload application	$20-$50k
Quarterly	6	TD Charitable Foundation	Online application	$10-$20k
Quarterly deadlines	5	John Merck Fund	send LOI or call first	
Spring, Fall	6	Alexander Eastman Foundation	Email application	$10-$50k
None	6	New York Community Trust	LOI	$20-$100k
None	6	Barr Foundation	300-400 word LOI	
None	6	Oak Foundation U.S.A.	LOI via email	
None	**6**	Endowment for Health, Inc.		
None	6	Jack and Dorothy Byrne Foundation, Inc.	LOI	$20k
None	5	David and Lucile Packard Foundation	LOI	$50-100k
None	**5**	Agnes M. Lindsay Trust	LOI	$5k
None	**7**	New Hampshire Charitable Foundation		
None	7	Department of Energy - Cons. Block Grants		
None	6	Stantec Community Engagement Grant	Online application	
None	6	Cogswell	Mail application	
None	5	Boston Foundation Inc		
None	5	Weyerhaeuser Company Foundation		
None	5	Bank of New Hampshire	2-page app (on website)	
None	5	Environmental Protection Agency - Healthy Communities Grant Program		$25k

Table 3. List of non-profits contacted by RBG

NON-PROFIT	REPLY	STATUS
CATCH Neighborhood Housing Rosemary M. Heard, President 105 Loudon Road, Unit One, Concord, NH 03301	Possible	Feb. meeting
Clean Energy NH Madeleine Mineau, Executive Director 14 Dixon Avenue, Suite 202 Concord, NH 03301	Possible	Feb. meeting Henry
CLF New Hampshire Tom Irwin, Vice President and Director 27 N Main St, Concord, NH 03301	No thanks	Remove
Community Action Partnership of Strafford County Sarah Varney, Director of Advancement P.O. Box 160, Dover, NH 03821-0160	Yes	Feb. meeting Betsey/Bob
Community Action Program Belknap-Merrimack Counties; Jeanne Agri, Chief Executive Officer P.O. Box 1016, Concord, NH 03302	Yes	Feb. meeting Michael/Chris
Lakes Region Community College Dr. Larissa Baia, President 379 Belmont Road Laconia, NH 03246	Possible	Feb. meeting Andy Dunkin
New Hampshire Community Loan Fund Juliana Eades, President 7 Wall Street, Concord, NH 03301	Possible	Feb. meeting
NH Audubon Statewide HQ McLane Center Douglas A. Bechtel, President 84 Silk Farm Road, Concord, NH 03301	No reply	Remove
NH Charitable Foundation Richard Ober, President and CEO 37 Pleasant Street, Concord, NH 03301-4005	No thanks	Remove
NH Residential Energy Performance Association 54 Portsmouth Street Concord, NH 03301	Possible	Feb. meeting Board
Southern NH Services Ryan Clouthier, Deputy Director 160 Silver St, Manchester, NH 03103	Yes	Feb. meeting Ryan/Dan
Southwestern Community Services John Manning, Chief Executive Officer PO Box 603, Keene, NH 03431	Yes	Feb. meeting Jim/Gabe
The Nature Conservancy Mark Zankel, New Hampshire State Director 22 Bridge Street, 4th Floor. Concord, NH 03301	On site meeting. later reply No thanks	Remove
Tri-County Community Action Program Jeanne L. Robillard, CEO 30 Exchange St. Berlin NH 03570	No reply	Remove
New Hampshire Housing Christopher Miller, Senior Director of Strategic Initiatives 32 Constitution Drive, Bedford, NH 03110	On site meeting. Possible	Feb. meeting Dean/Chris
Community Development Finance Authority Katherine Easterly Martey, Executive Director 14 Dixon Ave., Concord, NH 03301	On site meeting with Katy and Scott. Yes	Meeting following 1/24/20 meeting with team

RESILIENT BUILDINGS
— GROUP —
Superior energy performance

RE: NHSaves Partnership Initiative

<ADDRESS>

Dear *xxxxxx,*

Resilient Buildings Group, Inc (RBG) has been awarded a contract by the Sponsors of NHSaves® , consisting of the four (4) Utilities, Eversource, Until, Liberty Utilities, and New Hampshire Electric Cooperative (NH Utilities), to put forward an initiative (the NHSaves Partnership) to seek and obtain funding to enhance the current NHSaves energy efficiency programs in partnership with local non-profit partners. RBG has subcontracted to Aaron Rome Consulting of RI for the grant writing portion of this contract.

We have started the project with the first task of identifying potential funding sources. These funding sources range from available grants to Foundations and National Organizations such as the Department of Energy, Health and Human Services, Environmental Protection Agency, and others. The funding through this partnership could be but are not limited to a focus on health and safety measures allowing for the weatherization of certain homes and businesses, enhancing existing home weatherization rebates to make it easier for moderate-income customers to participate, and/or for economic development by supplementing rebate offerings to small businesses. Our main goal is to find funding that is complementary to the current NHSaves programs, which service both the Commercial and Residential sectors with energy efficiency technical advice and rebates. If you are not familiar with these programs, please reference the NHSaves website at www.nhsaves.com for more information or give me a call.

The second task of this project is to identify interested non-profit partners that have a goal or mission that aligns closely with the energy savings goals of the NHSaves programs as well as the focus of the funding. The potential partner would need to work in conjunction with the NH Utilities by receiving the organization or foundation funding, by paying incentive funds to customers/contractors in conjunction with the NH Utilities as grant funds will not be received by the NH Utilities, and by assisting with administrative requirements of the foundation or grant organization.

I am sending you this letter to ask if your organization is interested in further discussing becoming the non-profit organization in this endeavor to enhance the funding for the NHSaves Partnership Initiative. If you would like to learn more and have an interest, I would like to come to your organization to explain further and answer any questions that you may have.

Thank you for your time and consideration. Please feel free to contact me at dnute@resilientbuildingsgroup.com or 603-226-1009 X212.

Sincerely,

Dana Nute

President

Attachment P: Proposed 2022-2023 EM&V Expenses

The 2022-2023 EE Plan includes EM&V Expenses as shown in Table 1. The following narrative provides an explanation of how these costs were derived, including consulting and contractor costs.

Table 1. Proposed EM&V Expenses in 2022 and 2023

EM&V Tasks	2022	2023
1. Activities to support regulatory and other mandated reporting requirements	**$1,415,132**	**$1,478,026**
a. ISO NE certification of utility demand resources[1]	*$57,814*	*$60,346*
b. Utility modeling and tracking system software	*$434,535*	*$446,523*
c. AESC Study	*$0*	*$45,034*
d. TRM Hosting	*$48,631*	*$51,538*
e. Internal staff time for EM&V and other supporting efforts	*$874,152*	*$874,585*
2. Third-party EM&V Studies	**$628,750**	**$1,566,250**
3. Department of Energy Consultants Support	**$99,750**	**$104,738**
Total EM&V Budget	**$2,143,632**	**$3,149,013**

1. **Activities to support regulatory and other mandated reporting requirements**: As described in the narrative of the plan (Section 6.1), these efforts are necessary to meet NH Utilities' reporting requirements. Costs are estimated by each utility based on prior costs and anticipated increases due to the additional evaluation work anticipated in 2023 compared to 2022. The proposed budget in 2023 also includes funds for the AESC study which is expected to be launched in 2023. Narrative descriptions of each tasks are included in Section 6.1 of the Plan.
2. **Third party EM&V studies:** Two of the proposed EM&V studies described in Section 6.1 were initiated in 2021, and therefore have already been put out to bid, and contractors selected, thus costs are known. These studies are the NH Baseline Practices Study ($160,000) and the Large C&I Impact Evaluation ($425,000). The remaining studies described in Section 6.1 are proposed to be initiated in the 2022-2023 term, and therefore have not yet been put out to bid and exact contractor costs are not yet known. The EM&V Working Group estimates that the total amount needed to complete the 10 identified studies is $1,525,000, (with an average cost per study of $152,500, a low of $50,000/study and a high of $500,000/study). For budgeting purposes, this budget assumes that up to 80% of study budgets would be expended by the end of 2023, with remaining research and associated expenses to occur in the 2024-2026 term. In addition, $390,000 is held in reserve for emerging issues if research is needed to respond to changes in purchasing behavior, new technologies, market dynamics, and stakeholder priorities. Such emerging issues research would have oversight of the EM&V Working Group, which would

[1] Costs shown in italics are estimates at the time of filing.

ensure that emerging issues research fit within the overall priorities of the Strategic Evaluation Plan. The budget estimates in the table above are derived as follows:

a. 2022 Third-Party EM&V Study costs equal the full cost of the NH Baseline Practices Study plus 75% of the cost of the Large C&I Impact Evaluation, based on the assumption that the Large C&I Impact Evaluation will not finish in 2022, plus $150K in emerging issues for 2022. [($160K +75%($425K)+$150K)=$628,750]
b. 2023 Third-Party EM&V Study costs equal the remaining 25% cost of the Large C&I Impact Evaluation plus 80% of the $1,525,000 cost of the 10 proposed studies plus $240K in emerging issues for 2023 [25%($425K)+80%($1,525K) + $240K=$1,566,250]

3. **Department of Energy Consultants Support:** The costs for the Department of Energy Consultants represent the contracted costs for the EM&V Consultants hired by the Department of Energy to support the EM&V Working Group and to provide technical advice and support to EM&V studies. An inflation factor has been applied to 2023 expenses.

2018-2020 EERS Working Groups

- **EM&V.** This working group kicked off in January 2018 and continues to meet at least monthly to oversee a range of research activities to ensure continuous improvement in the programs, and how savings are measured and claimed. This working group has developed and updated New Hampshire's Technical Resource Manual ("TRM"), which is the repository for all assumptions and calculations for every measure offered by the NHSaves programs. Membership consists of representatives from each of the NH Utilities, as well as staff from the NH Department of Energy ("NH DOE"), evaluation consultants and a representative appointed by the EESE Board.
- **Funding and Financing.** This working group kicked off in January 2018 and concluded its work in 2020 with a report, titled, "NH Saves: External Funding and Partnership Assessment" (see Attachment O). In this document, the working group discussed two phases of investigations and four potential strategies to seek funding and partnership opportunities, and quality-improvement ideas. The working group also identified four important insights, including:
  - NH-based charitable foundations hold the most potential for external funding and local non-profits are best-positioned to identify and receive funding from specific grant opportunities.
  - Community Action Agencies ("CAAs"), largely responsible for implementing residential weatherization programs, are hampered by a shortage of contractors, and by cash-flow issues.
  - Other institutional stakeholders (Department of Health and Human Services ("DHHS"), NH Housing Finance Authority ("NHHFA")) are particularly interested in the connection between weatherization and public health. These organizations are aware of and leverage weatherization program funding and suggest that implementation efficiency and outreach could improve with a streamlined administrative process.
- **Benefit/Cost (BC) Test.** This working group met over the course of 2018-2019 and developed a consensus proposal that led to the creation of the Granite State Test, as described in the BC section of the Plan.
- **PI**. This working group met over the course of 2018-2019 and developed a consensus proposal that updated the PI framework utilized by the NHSaves programs, as described in the PI section of the Plan.
- **LBR**. This working group met over the course of 2018 and developed a consensus report that recommended a consistent methodology for future LBR calculations. This included a separate Average Distribution Rate for kWh and another for kW, replacing the previously utilized Average Distribution Rate that incorporated both components.
- More information on all 2018-2020 EERS Working Groups can be found at the PUC's site: https://www.puc.nh.gov/EESE%20Board/EERS_Working_Groups.html