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Heating Sector Transformation in Rhode Island: Technical Support Document

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Notice

This Technical Support Document was prepared by The Brattle Group for the Rhode Island Office of Energy Resources (OER) and the Rhode Island Department of Public Utilities and Carriers (DPUC). It is intended to be read and used in combination with the report titled Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, also prepared by The Brattle Group. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

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I. Introduction

This Technical Support Document accompanies the report titled [Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050] (the "Report"). The goal of this document is to provide additional detail on the analyses supporting the Report, including an overview of the analytic methodology and assumptions used. The analysis is based on four separate models, illustrated schematically in **Figure 1**. Except for the building stock model, which was developed by Buro Happold Engineering (subcontractor to The Brattle Group), these models are proprietary models of The Brattle Group.

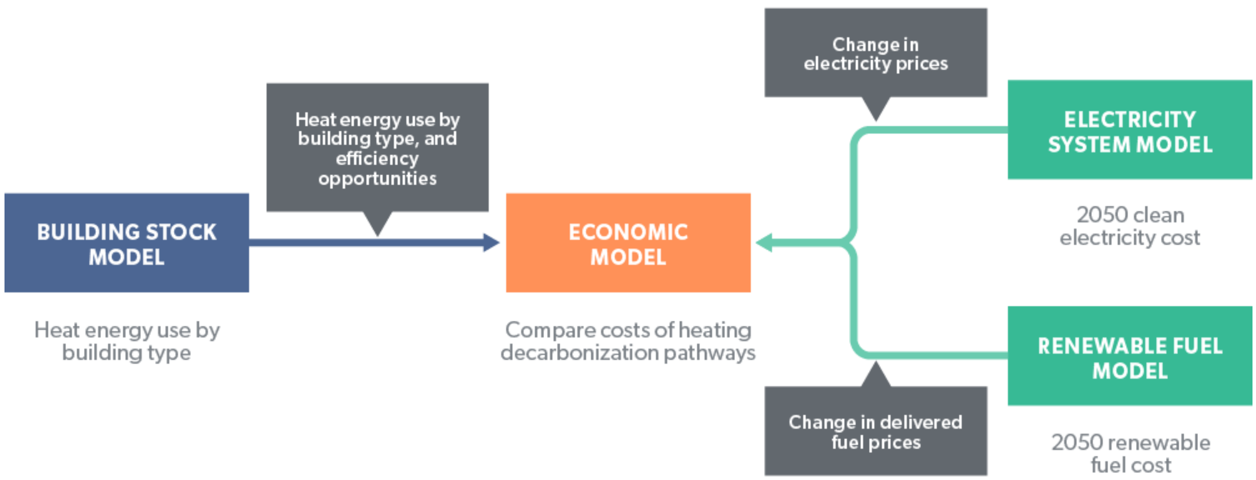

FIGURE 1: ANALYTICAL MODEL OVERVIEW

The economic model is the main tool used to estimate and compare the annualized costs of the multiple heating decarbonization solutions considered. For a specified building type, the economic model estimates the building's hourly heating demand profile (based on weather data) and the required capital and variable costs of the heater. A key input to the economic model is the average annual space heating requirement for the specified building type; this is provided by the building stock model. Another key input and cost driver is the estimated price of various types of fuel in 2050 (e.g., carbon-free fuels such as renewable – electricity, renewable oil, and renewable gas). The electricity price is determined by the electricity system model. This model has been used in various decarbonization pathway analyses performed by Brattle and is described in greater detail in a report titled "Achieving 80% GHG Reduction in New England by 2050;"[1] a separate technical support document describes its underlying assumptions.[2]

[1] J. Weiss, et al., "Achieving 80% GHG Reduction in New England by 2050: Why the Region Needs to Keep its Foot on the Clean Energy Accelerator," September 2019. https://brattlefiles.blob.core.windows.net/files/17233_achieving_80_percent_ghg_reduction_in_new_england_by_20150_september_2019.pdf

[2] J. Weiss, et al., "Achieving 80% GHG Reduction in New England by 2050: Technical Appendix," September 2019. https://brattlefiles.blob.core.windows.net/files/17245_achieving_80_percent_ghg_reduction_in_new_england_by_2050_technical_appendix.pdf

For this project, the electric system modeling was extended to enable estimating the average retail cost of electricity with a decarbonized future electric system.

The price of other renewable fuels was estimated using the renewable fuels model. The remainder of this Technical Support Document describes the methodology and key assumptions used in each of the four models in greater detail. Section II describes the building stock model, Section III the economic model, and Section III.C.3 the electricity system and renewable fuel models.

II. Building Stock Model

Buro Happold Engineering (Buro Happold), a subcontractor in this study, provided The Brattle Group with a detailed analysis of the residential and commercial building stock in Rhode Island, including energy consumption by end-use and fuel type. Summaries of this analysis are presented here.

The annual average space heating requirements (in terms of MMBtu heat input) for a representative single-family residential home and commercial building in Rhode Island are a key input to the financial model. Buro Happold's estimates for these values are summarized in **Figure 2** and **Figure 3**. For Rhode Island's residential sector, Buro Happold estimated that the average space heating energy requirement for a single-family home is approximately 89 MMBtu per year. This estimate is somewhat higher than the average across the residential sector, 62 MMBtu per year, reflecting that multi-family dwellings typically have lower average heat requirements.[3]

[3] This average value for Rhode Island, 62 MMBtu per year, aligns closely with the EIA's estimate for New England, which is 59 MMBtu per year. (EIA, Residential Energy Consumption Survey 2015, Annual household site end-use consumption in the Northeast; data for New England region.)

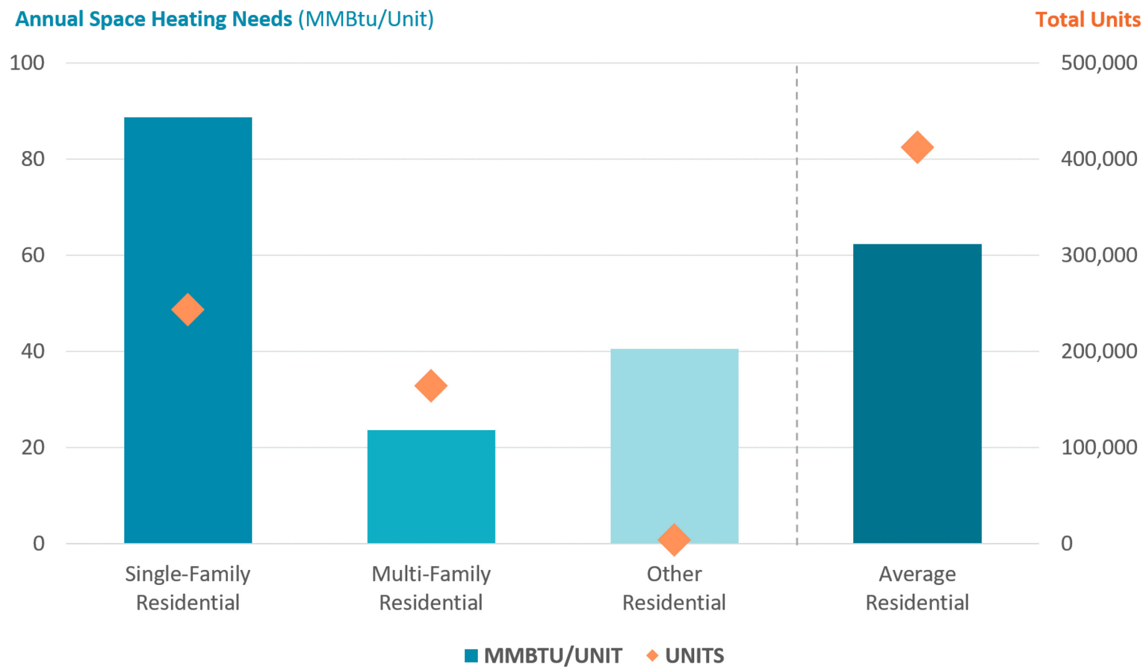

FIGURE 2: RESIDENTIAL BUILDING STOCK AND ENERGY CONSUMPTION

Source: Buro Happold Engineering, Rhode Island Building Stock Modeling.

For the commercial sector, Buro Happold's analysis estimated that, on average, commercial buildings consume 38,305 Btu per square foot per year to meet their space heating energy requirements, as shown in **Figure 3**. EIA data shows that there are 302,000 commercial buildings in New England, with a total square footage of 4,302 million, resulting in an average commercial building size of 14,250 square feet.[4] Lacking specific data on building size for Rhode Island, this New England average was used to determine the size of a representative Rhode Island commercial building. This yields an estimated annual heat demand of 546 MMBtu for a representative commercial building.

[4] EIA, 2012 CBECS Survey Data, Table C1: Total Energy Consumption by Major Fuel.

FIGURE 3: COMMERCIAL BUILDING STOCK AND ENERGY CONSUMPTION

Source: Buro Happold Engineering, Rhode Island Building Stock Modeling.

III. Economic Model

The economic model used in the analysis compares the annualized heating costs of various types of heating solutions in a given building type, focusing on 2050 when the analysis assumes the Rhode Island heating sector must be decarbonized. Space and domestic water heating needs are considered separately. All costs are evaluated in real terms, in 2018 dollars.

Annualized costs are estimated for two building structures: a representative existing detached single-family home, and a representative existing mid-sized commercial building. The space heating cost components modeled in the analysis include:

- Capital costs, including
  - Assumed energy efficiency improvements
  - Furnace, boiler and electric heat pump costs, including ground loop cost for GSHPs, all inclusive of installation costs
  - Assumed ducting, and electrical upgrade costs (for heat pumps installed to replace a furnace or boiler)
- Space heating operating and maintenance costs
  - Cost of fuel and/or electricity
  - Maintenance costs

- Avoided costs of air conditioning replacement (for heat pumps, which eliminate the need for air conditioning since they can also provide cooling)
- Social cost of carbon, including both the net carbon emissions from combusting fuel and GHG implications of methane leaks

A. ENERGY EFFICIENCY

Energy efficiency can play a key role in reducing the heat requirements of a building, and thus reducing customer costs. For example, weatherization improvements such as air sealing, weather-stripping, and attic insulation for an existing building tend to be reasonably low cost in Rhode Island and do not require intrusive interventions in the building; they have represented the bulk of building envelope-related energy efficiency measures to date. Based on available evidence, they often appear to be the most cost-effective measures for existing buildings. These relatively simple measures typically achieve a moderate impact on overall heating demand for an existing building; in aggregate, they tend to reduce energy needs on the order of 10–15%.[5] As described in the Report and below, deep decarbonization of the heating sector may warrant additional energy efficiency investments to further reduce building heat loads and associated energy costs.

A recent Massachusetts evaluation concluded that, on average, weatherization under the Home Energy Services programs reduced average household gas consumption by 13 MMBtu per year (this is 15% of the representative Rhode Island home's heating energy needs that were found above). Of the evaluated participants, attic insulation and air sealing were performed in 85% and 88% of cases, respectively. Floor and wall insulation were only performed in 23% and 22% of the cases. Air sealing alone reduced natural gas consumption by 3.2 MMBtu.[6] The most recent evaluation of Rhode Island energy efficiency program evaluation of residential and gas-use related measures concluded that air sealing measures typically saved 3.6 MMBtu per year, while attic insulation saved 5.0 MMBtu.[7] Given that the average single-family home uses approximately 89 MMBtu for space heating per year[8], this suggests that air sealing measures tend to result in energy savings of approximately 4% of annual heating-related energy consumption, with attic insulation resulting in approximately 6% savings. According to the same evaluation studies, all

[5] When evaluated in a bundle with insulation, an evaluation of Maine weatherization programs found an average reduction of 17.9 MMBtu or 17% relative to pre-measure energy consumption in homes heated with natural gas. A comparison with other air sealing and insulation programs suggests a typical range of savings between 9% and 17%. West Hill Energy and Computing, Efficiency Maine Trust Home Energy Savings Program Impact Evaluation, Program Years 2014–2016, August 23, 2019, p. 23, Table 3-5.

[6] Home Energy Services Impact Evaluation (Res 34), Produced in collaboration with Navigant and Cadeo, prepared for the Electric and Gas Program Administrators of Massachusetts, August 2018, Table 5-4, p. 15.

[7] DNV-GL, Impact Evaluation of 2014 EnergyWise Single Family Program, National Grid Rhode Island, August 16, 2016, Table 3-4, p. 26.

[8] Buro Happold Engineering, Rhode Island Building Stock Modeling. Space heating demand for the average single-family home in Rhode Island is 89 MMBtu per year. One therm equals 100,000 Btu, or 0.10 MMBtu.

weatherization related measures combined (air sealing, attic insulation, and wall and floor insulation) result in average energy savings of about 13%.[9]

Once the relatively simple and less intrusive measures have been undertaken in a given building, achieving further reductions in heat energy requirements would require additional measures that have a higher cost and are generally more intrusive. These types of activities, sometimes referred to as “deep” energy retrofits, may include measures such as window replacement and adding insulation to exterior walls and floors. Such activities tend to be more disruptive and much more costly when retrofitting an existing building. This is complicated by the fact that the necessary interventions in an existing building can be highly idiosyncratic to the individual building and difficult to standardize. The cost of a deep energy retrofit can exceed $50,000 or even $100,000 for a residential home, with comparably high costs for most commercial buildings. Such measures may not be cost-effective in existing buildings; at the very least, they face a very significant initial cost barrier and tend to be disruptive.[10]

The analysis in this study assumes that essentially all residential and commercial buildings in Rhode Island will implement a set of relatively low-cost retrofits (air sealing, weatherstripping, attic insulation) by 2050 to reduce their heating costs. These measures would reduce their total annual space heating energy demand by about 15%, from 89 MMBtu per year (see **Figure 2**) to 76 MMBtu for single-family homes, and from 546 MMBtu (**Figure 3**) to 464 MMBtu for commercial buildings.

B. SPACE HEATING DEMAND PROFILES

To estimate the capital and variable costs of space heating, it is necessary to develop daily and hourly heating demand profiles, which are converted into daily and hourly electricity or fuel demands. Annual space heating demand was converted into first daily and then hourly heating demand by using historical New England heating degree days data from 2018, and the daily space heating demand profiles shown in **Figure 4**, from EPRI.[11]

9 DNV-GL, Final Core Report, 2013–2017 Residential Customer Profile Study, Study number MA19X08-B_2017RESCUSTPRO, July 1, 2019, Table 5-8, p. 35.

10 Home Energy Services Impact Evaluation (Res 34), Produced in collaboration with Navigant and Cadeo, prepared for the Electric and Gas Program Administrators of Massachusetts, August 2018, page 26.

11 Obtained from National Oceanic and Atmospheric Administration, Climate Prediction Center. Downloaded from: ftp://ftp.cpc.ncep.noaa.gov/htdocs/degree_days/weighted/daily_data/

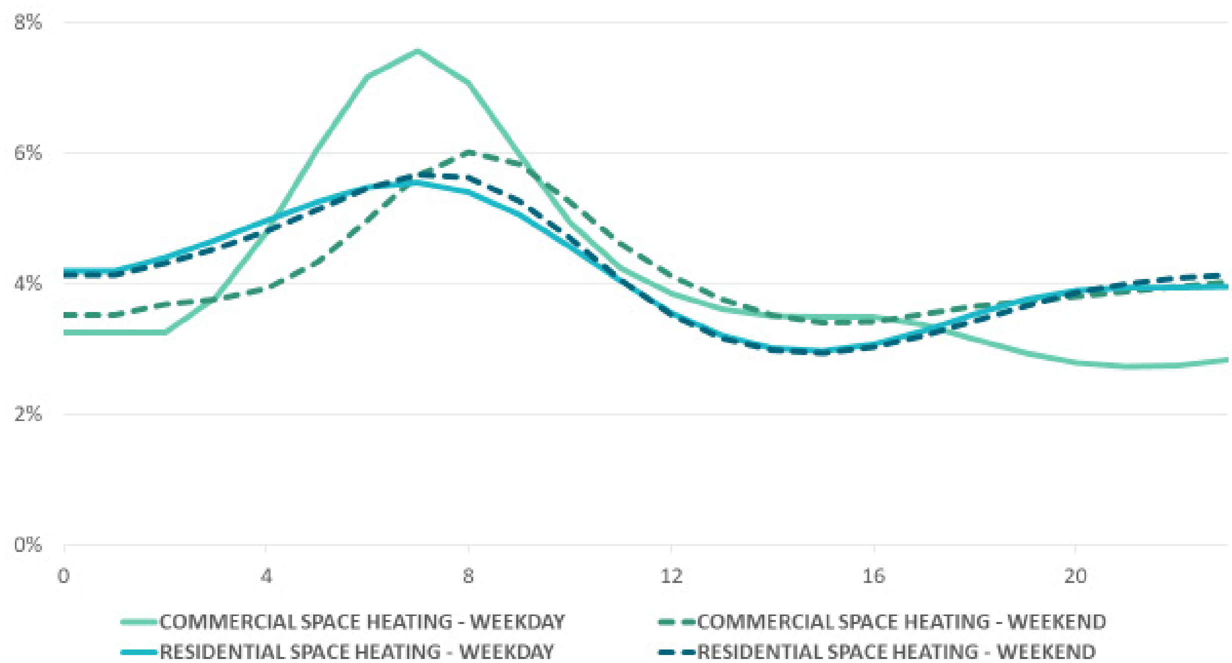

FIGURE 4: SPACE HEATING AVERAGE LOAD PROFILES

Source: EPRI, End Use Load Shapes. Available at: https://loadshape.epri.com/enduse.

Based on the hourly spaced heating analysis outlined above, a representative single-family home with an annual space heating demand of 76 MMBtu per year would have a peak space heating demand of 44,800 Btu/hr. A 3–5 ton ASHP could meet almost all of a representative single-family home's space heating demand with a heating load of 68–87 MMBtu per year.[12] However, this size ton ASHP would not be able to meet all of the demand during the coldest, highest demand hours of the year, when the temperature outside is so low that the ASHP efficiency drops to near 100%. In those extreme cold weather hours, a secondary heat source would be needed to supplement the ASHP. Even though ASHPs can be sized to provide sufficient heat during very low outdoor temperatures, the required "oversizing" of the heat pump tends to be uneconomical, as illustrated in **Figure 5**. Where heat pumps replace (or complement) an existing heating system, the existing heating system can be retained to provide backup heat, at least until that system requires significant investment (such as replacing a furnace). This analysis assumes an ASHP size of 5 ton for the representative single-family home, which would meet almost all the home's heating needs, but would require some supplemental heating to meet peak demand during the coldest hours of the year, as shown in **Figure 5**.[13]

12 NYSERDA, "New Efficiency: New York. Analysis of Residential Heat Pump Potential and Economics. Final Report," January 2019, Table 4-7.

13 ASHPs currently installed in single-family homes tend to be smaller. However, this is primarily because heat pumps are designed to provide sufficient air conditioning and only partial heating, with typical legacy heating systems providing significant supplementary heat. This analysis models heat pumps to meet almost all heating requirements, with electrical resistance heating supplying supplementary heat during very few hours of extreme outdoor temperatures.

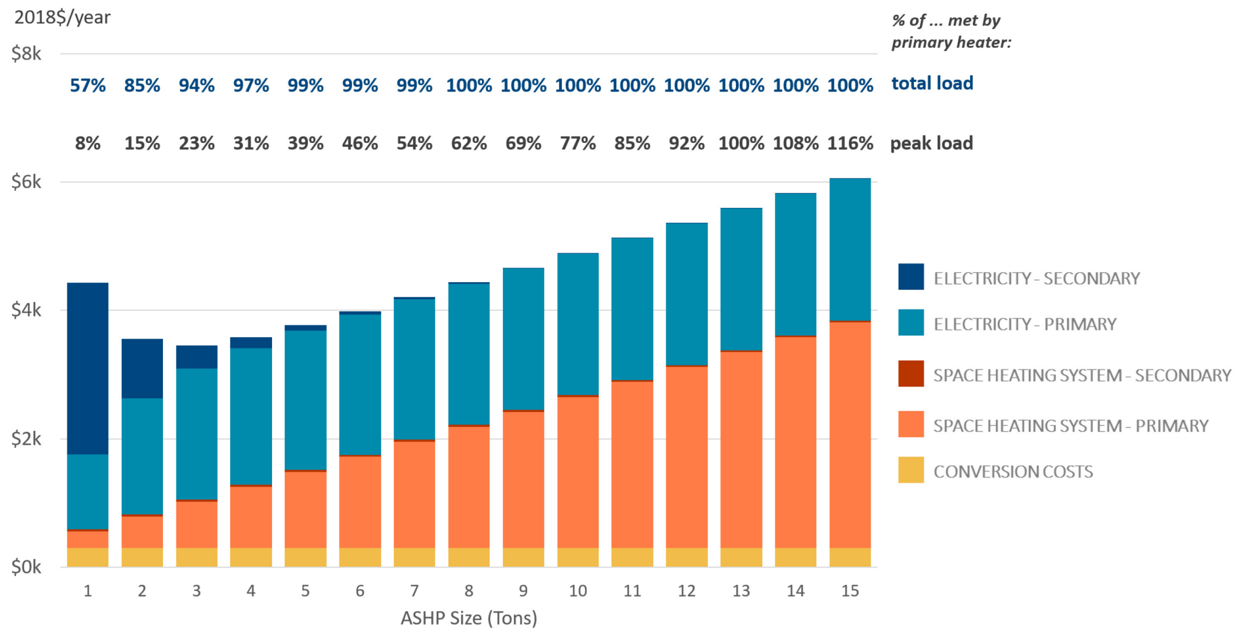

FIGURE 5: ANNUALIZED ASHP SPACE HEATING COST VS HEAT PUMP SIZE SINGLE-FAMILY HOME

GSHPs for a single-family home are usually sized at 4–5 tons, for both existing and new construction.[14] To make the GSHP and ASHP costs more comparable, the GSHP size selected for this analysis was also 5 tons. This would meet 100% of the representative single-family home's space heating annual demand and its peak demand, allowing a 30% capacity margin to account for extreme weather events, as illustrated in **Figure 6**.

[14] NYSERDA, "New Efficiency: New York. Analysis of Residential Heat Pump Potential and Economics. Final Report," January 2019, Table 4-7.

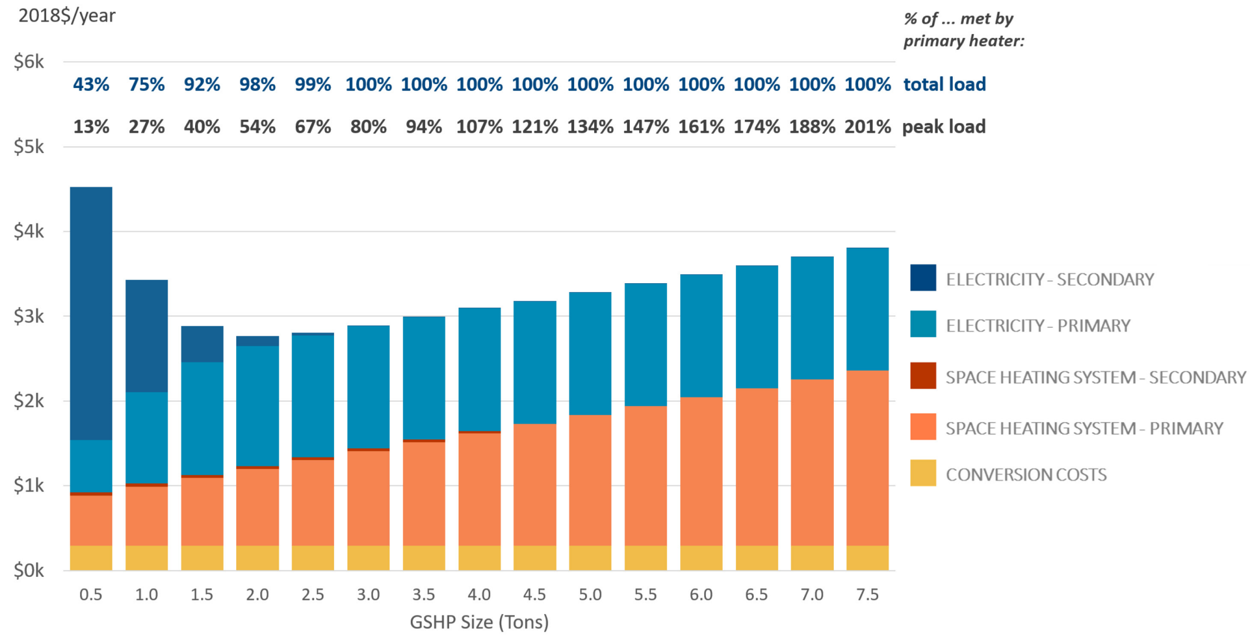

FIGURE 6: ANNUALIZED GSHP SPACE HEATING COST VS HEAT PUMP SIZE SINGLE-FAMILY HOME

The size of the residential fuel furnace or boiler (both renewable and fossil) was determined based on the range of sizes for a representative home (50,000 – 140,000 Btu/hr).[15] This analysis assumes a furnace/boiler size of 90,000 Btu/hr, which would meet around 200% of the estimated peak demand for the representative single-family home modeled.

Similar to the residential analysis, the heater sizes for the average commercial building were based on the space heating demand profiles derived in this analysis, which result in an average annual space heating demand of 464 MMBtu – after accounting for energy efficiency improvements – and a peak demand of approximately 365,000 Btu/hr. A 36-ton GSHP could meet the space heating needs for this representative commercial building, allowing for a 20% margin beyond the modeled peak demand for extreme weather events, as shown in **Figure 7**.

15 HomeAdvisor, "How Much Does A New Gas Furnace Cost?" accessed on January 31, 2020 at: https://www.homeadvisor.com/cost/heating-and-cooling/gas-furnace-prices/

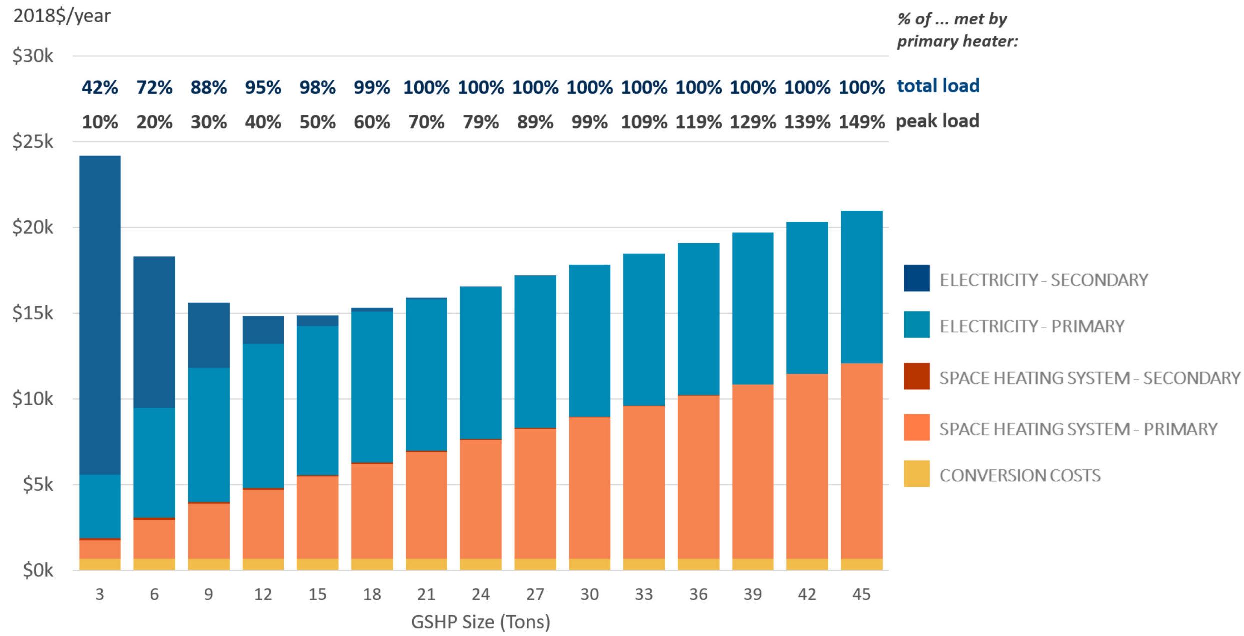

FIGURE 7: ANNUALIZED GSHP SPACE HEATING COST VS HEAT PUMP SIZE REPRESENTATIVE COMMERCIAL BUILDING

The analysis assumes a size of 36 tons for the ASHP as well, which would meet almost all of the commercial building's energy demand, but only about 40% of the peak heat demand on the coldest days, as illustrated in **Figure 8**; electric resistance heating was included to supplement to meet peak load plus a 20% margin. Similar to the residential analysis, the furnace/boiler was sized to meet 200% of peak demand.

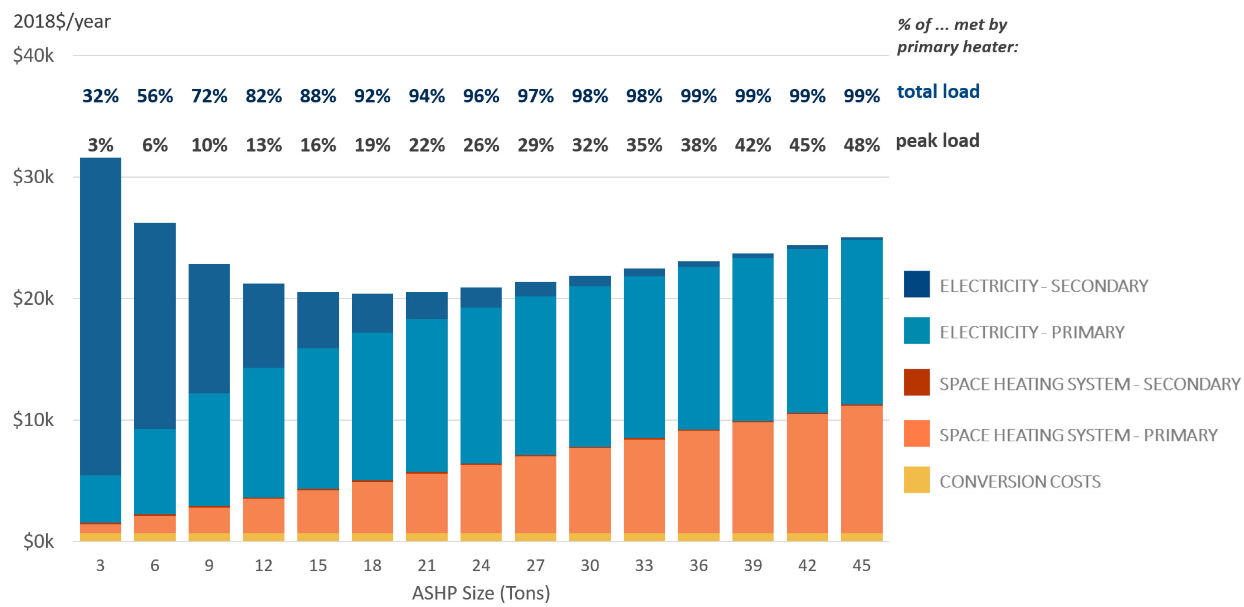

FIGURE 8: ANNUALIZED ASHP SPACE HEATING COST VS HEAT PUMP SIZE REPRESENTATIVE COMMERCIAL BUILDING

Using the assumptions summarized in **Table 1** for all technologies other than ASHPs (whose efficiency depends on outdoor temperature; see below), average heater efficiencies were used to convert modeled hourly space heating demand into the corresponding hourly demand for fuel or electricity.

	2020	2050
Gas Furnace/Boiler	80%	93%
Oil Furnace/Boiler	83%	84%
GSHP	360%	360%
Electric Resistance	100%	100%

TABLE 1: SPACE HEATER AVERAGE EFFICIENCIES

Sources: Gas furnace/boiler, oil furnace/boiler, and electric resistance efficiencies are based on the ranges provided by a study from the EIA.[16] The GSHP efficiency is based on a review of studies by NYSERDA and the EIA.[17]

Since the efficiency of an ASHP varies by outdoor temperature, the electricity demand of ASHPs was modeled at an hourly level as a function of outdoor temperature. The relationship between the ASHP's efficiency (also known as Coefficient of Performance (COP)) and temperature was based on the Northeast Energy Efficiency Partnerships (NEEP) cold climate ASHP standards, which prescribe 175% efficiency (a COP of 1.75) at 5 degrees Fahrenheit and 400% efficiency (a COP of 4) at 47 degrees Fahrenheit.[18] An additional 15% derate factor was applied to these standards to account for the difference between the rated and actual performance of ASHPs.[19] The relationship between outside temperature and ASHP performance is shown in **Figure 9**. We used a historical hourly temperature profile for New England based on available data from 2001 to 2016 to calculate the hourly efficiency for a typical ASHP in a typical year.[20]

16 EIA, "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies," June 2018.

17 NYSERDA, "Analysis of Water Furnace Geothermal Heat Pump Sites in New York State with Symphony Monitoring Systems," December 2017.

EIA, "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies," June 2018.

18 NEEP, Cold Climate Air-Source Heat Pump Specification.

19 See Maine Climate Council Buildings, Infrastructure, and Housing Working Group: Briefings on alternative fuels and beneficial electrification, April 14, 2020. Similarly, interviews with heat pump manufacturers and installers suggested that a realistic estimate of field performance may be about 10–20% below rated performance; this accounts for a number of factors, including less than ideal site conditions, improper installation, defrost cycle, age, etc.

20 Temperature data obtained from the National Solar Radiation Database (NSRDB). The temperature profile used in the analysis is based on the average historical temperatures for the 11 most populated cities in New England.

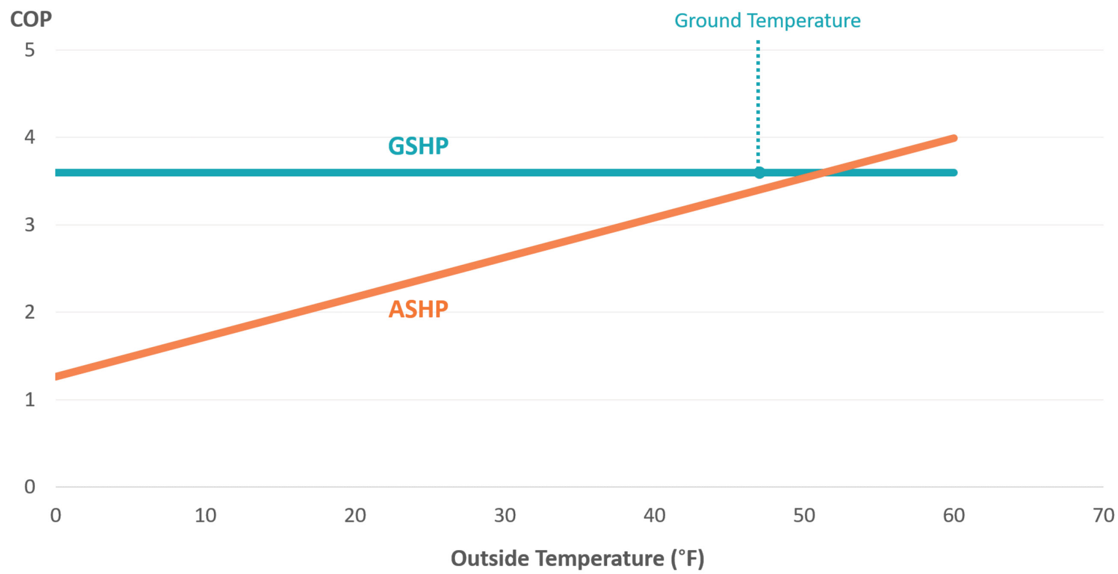

FIGURE 9: **RELATIONSHIP BETWEEN OUTDOOR TEMPERATURE AND HEAT PUMP EFFICIENCY (COP)**

C. SPACE HEATING COSTS

The core economic model of space heating costs annualizes the various costs associated with heating, levelizing the initial cost of necessary capital investments over the life of the equipment (different components may have different lives), and adding the annual operating costs (mostly fuel or electricity, with modest maintenance costs assumed). It considers relevant capital costs, including both equipment and installation costs of the heating equipment, either a furnace/boiler or electric heat pump. By including the cost of a replacement furnace/boiler in an existing home that already has one, this analysis assumes that any change of heating system would be timed to coincide with the end of life of the old system, and thus avoids the cost of replacing it. Similarly, the analysis also includes the avoidable capital cost of an assumed central A/C system for furnace/boiler systems, since heat pumps provide cooling as well as heat, and so avoid the installation or replacement cost of air conditioning equipment. For all types of heating systems, the analysis assumes cost-effective energy efficiency investments would be made by 2050. The analysis does not explicitly consider the timing or sequence of the investments, though the capital and fuel cost estimates that go into the economic model represent costs as of about 2050.

The cost of renewable fuels (for heating with furnaces or boilers using Renewable Gas or Renewable Oil) is developed by the Renewable Fuels Model. The cost of electricity for heat pumps (GSHP or ASHP) is developed by the Electricity System Model, which takes into account the additional electric load from heat pumps and how it would affect the electricity system and the delivered price of electricity. For both fuels and electricity, we estimate the split between the underlying commodity cost and the delivery cost.

The economic model also accounts for the social cost of GHG emissions, including both the direct emissions from fossil combustion (CO_2) and the GHG from methane leaks, which apply to both fossil and renewable gas.

Since this analysis takes a social perspective on costs, it uses a low social discount rate of 3% to levelize capital costs. This perspective may not accurately represent consumers' decision-making if they face these up-front costs directly, however. Consumers typically require a short payback period for energy investments (i.e., the annual savings should repay the initial investment within just a few years). This might imply that consumers have a much higher discount rate, though alternatively, their decisions may be taking into account other factors not captured in the economic analysis (e.g., the disruption and inconvenience of a construction project, the possibility that a homeowner may move and not benefit from the full long-term stream of energy savings, etc.). This potential divergence between the social cost of heating solutions and private decisions about heating investments likely points to a need for policy solutions to encourage consumer investment.

1. Capital & Installation Costs

Cost-effective energy efficiency retrofits were included in the analysis. For the representative single-family residential home analyzed, the cost of such a retrofit was assumed to be $4,200, and that it would reduce the heat energy needed for the building by 15%, consistent with experience from Rhode Island's residential energy efficiency programs.[21] For the representative larger building analyzed, the energy retrofit cost was assumed to be $12,600, proportionally smaller than for residential buildings at the larger scale, with heat energy needs also assumed to decrease by 15%. This is not a differentiating factor among the decarbonized heating solutions, since it was assumed that essentially all buildings in Rhode Island would receive such retrofits by 2050, and the cost and energy savings assumed was the same for each of the alternative heating solutions.

The capital and installation cost of space heating equipment were determined based on the assumed equipment size. For furnaces and boilers, a linear relationship was used between size and capital and installation costs.[22] We assumed that for an existing building, a furnace (or boiler) would be a simple replacement of a previous furnace (or boiler) so that other changes to the building would not be necessary (e.g., no ductwork, electrical upgrades, etc.).

For electric heat pumps, a dataset on ASHP cost from MassCEC was used to derive the relationship between heat pump capacity and cost, illustrated in **Figure 10** below.[23] Due to limited and incomplete data for GSHP, and based on interviews with installers, the cost of GSHP was assumed to follow the same relationship derived for ASHPs (i.e., the installed cost of the same size heat pump would be about the same for GSHP as for ASHP), though of course the ground loop would be a separate and additional cost for the GSHP. Ground loop cost was assumed to be $15,000 for a representative Rhode Island

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21 Calculated based on National Grid, 2018 Energy Efficiency Year-End Report, May 15, 2019, p. 8 and Table E-3. Estimate includes total program cost for EnergyWise and customer costs and therefore include program costs other than actual installation (such as program administration and the cost of energy audits).

22 This linear relationship is based on the cost ranges by equipment size provided by HomeAdvisor.
HomeAdvisor, "How Much Does A New Gas Furnace Cost?" accessed on January 31, 2020 at: https://www.homeadvisor.com/cost/heating-and-cooling/gas-furnace-prices/

23 Data on the installed cost of heat pumps in Massachusetts was obtained from the Massachusetts Clean Energy Center (MassCEC), reflecting the total cost of projects that were supported by the state.

residential home, based on interviews with installers and the limited data on total GSHP system costs.[24] To incorporate the potential for further equipment cost reductions and reductions in installation costs as the market for both ASHPs and GSHPs grows in size and matures, it was assumed that heat pump installed cost would decline at an annual rate of 1% from 2020 to 2050; this accounts for a reduction in installed cost of approximately 25% by 2050 (the ground loop cost for GSHPs is assumed to remain constant in real terms over time). The cost of installing or replacing a central air conditioning system, which can be avoided with a heat pump installation, was assumed to be $5,000.[25] Finally, it was assumed that a representative single-family residential home would require additional conversion costs of approximately $5,000 to convert the heating system from a furnace or boiler to a heat pump; this would account for electrical upgrades, ductwork work, etc., which would likely be necessary in many if not most homes.[26] The installed cost assumptions for electric heat pumps and other fuel-based heating systems are included in **Table 2**. The capital space heater costs for the representative residential single-family home shown in this table are within the range of costs presented in a study performed by NYSERDA for the state of New York.[27]

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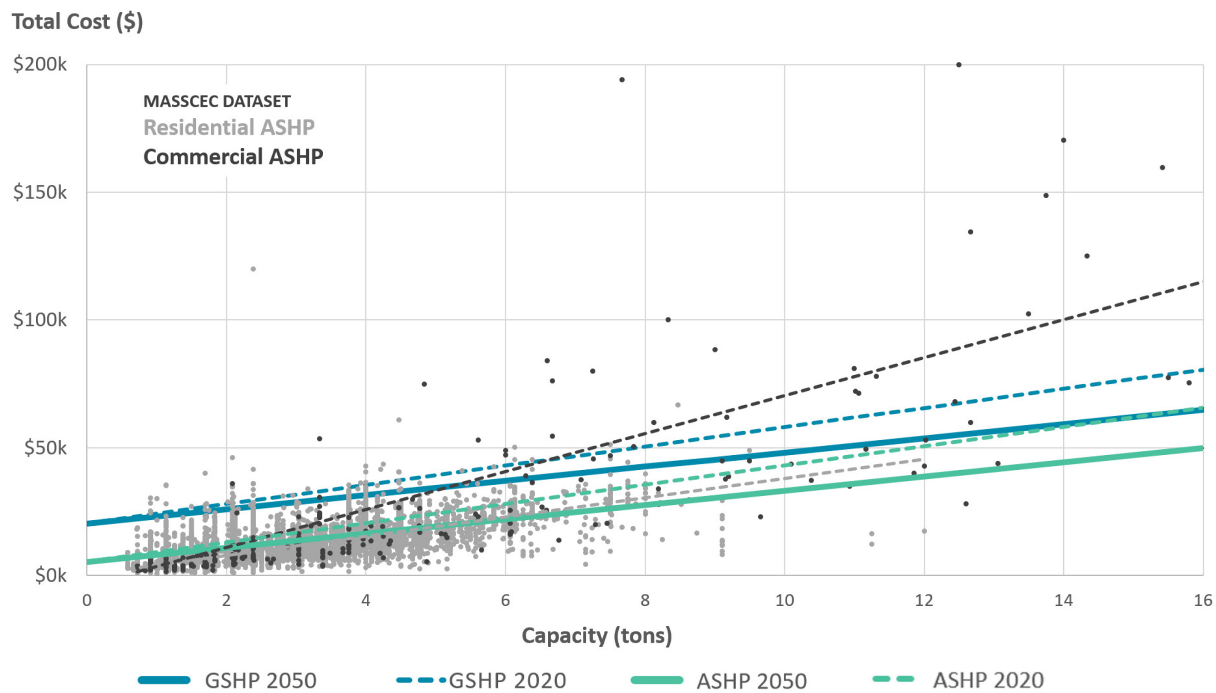
24 Reliable sources for GSHP cost data are difficult to come by, but another perspective suggests that GHSP costs vary widely, and might be somewhat lower than was assumed in the analysis. See https://www.thumbtack.com/p/geothermal-heating-installation-cost, which claims that a 2–3 ton GSHP with a horizontal ground loop to heat a 2,500 square foot home might cost as little as $15,000 installed.

25 Based on the range of estimates from HomeAdvisor. HomeAdvisor, "How Much Does It Cost To Install Central Air?" accessed January 31, 2020, available at: https://www.homeadvisor.com/cost/heating-and-cooling/install-an-ac-unit/#replace

26 The actual costs for electrical and ducting work depend on existing conditions at time of installation. Importantly, required ducting work may be limited in buildings with existing central heating or air conditioning systems. Also, in buildings with existing hydronic heating systems (using a boiler and radiators), existing heating infrastructure may be able to be repurposed by using air-to-water rather than air-to-air heat pumps. Air-to-air heat pumps (and more general forced air heating and air conditioning systems) are more prevalent in the United States residential sector, where air conditioning is common. In Europe, air-to-water heat pumps and hydronic heating systems are more widespread in the residential sector. The use of hydronic systems (using water to cool or heat spaces) is more common in the commercial building sector.

27 NYSERDA, "New Efficiency: New York. Analysis of Residential Heat Pump Potential and Economics. Final Report," January 2019.



Cost Regressions (MassCEC ASHP Dataset)

	Residential	Commercial
Sample Size	19,932	292
Formula	**HP cost = 3,762 * ton + 406**	**HP cost = 7,431 * ton – 4,004**
R^2	**0.58**	**0.48**

2020 Total Res. ASHP Cost:
(Cost of Res. ASHP) +
Conversion Costs =

(3,762 * ton + 406) + 5,000 =

3,762x + 5,406

2050 Total Res. ASHP Cost:
*(Cost of Res. ASHP) **
(Cost decline by 2050) +
Conversion Costs =

(3,762 * ton + 406) * (1-1%)$^{(2050-2020)}$ + 5,000 =

2,783x + 5,300

2020 Total Res. GSHP Cost:
(Cost of Res. ASHP) +
Conversion Costs +
Ground Loop =

(3,762 * ton + 406) + 5,000 + 15,000 =

3,762x + 5,406

2050 Total Res. GSHP Cost:
*(Cost of Res. ASHP) **
(Cost decline by 2050) +
Conversion Costs + Ground Loop =

(3,762 * ton + 406) * (1-1%)$^{(2050-2020)}$ + 5,000 + 15,000 =

2,783x + 5,300

FIGURE 10: RESIDENTIAL AND COMMERCIAL HEAT PUMP TOTAL INSTALLED COSTS, BY CAPACITY

For the representative larger building modeled (e.g., multi-family residential and commercial buildings), the same relationships were used for heating system costs, for both fuel-based systems and heat pumps. The larger heat needs would require larger, more costly equipment, though the linear cost relationships used involve a positive cost intercept, so costs scale up somewhat less than proportionally with heating system size. The ground loop cost was assumed to increase less than proportionally with the size of the system, reflecting economies of scale in drilling or digging for the ground loop. Again, see **Table 2** for the costs assumed.

	Residential			Commercial		
	Fuel-based	**GSHP**	**ASHP**	**Fuel-based**	**GSHP**	**ASHP**
Primary Heater (2050)	$6,200	$14,200	$14,200	$32,700	$100,500	$100,500
Primary Heater (2020)	$6,200	$19,200	$19,200	$32,700	$135,900	$135,900
Annual Cost Decline	0%	-1%	-1%	0%	-1%	-1%
Secondary Heater	n.a.	n.a.	$500	n.a.	n.a.	$1,500
Ground Loop	n.a.	$15,000	n.a.	n.a.	$71,200	n.a.
Electrical and Ducting	n.a.	$5,000	$5,000	n.a.	$15,000	$15,000
A/C Replacement	$5,000	n.a.	n.a.	$15,000	n.a.	n.a.
Total	$11,200	$34,200	$19,700	$47,700	$186,700	$117,000

TABLE 2: INSTALLED COST OF HEATING SYSTEMS ASSUMED FOR ANALYSIS, 2050 (2018$)

Total installed equipment costs were annualized using the economic lifespans listed below in **Table 3**, and using a (low) social discount rate of 3% to reflect society's perspective, recognizing that this discount rate will not necessarily reflect the behavior of consumers when they are choosing a heating system.

Installation Component	Avg. Economic Life
GSHP Loop	50 yrs[28]
Furnace/Boiler	20 yrs
GSHP	20 yrs
ASHP	15 yrs
Ducting/Electrical	50 yrs
Energy Efficiency	50 yrs

TABLE 3: AVERAGE ECONOMIC LIFE OF SPACE HEATING SYSTEM COMPONENTS

28 "Correctly installed, permanent loops require almost no maintenance or replacement for 50+ years." HomeAdvisor, "Install a Geothermal Heating or Cooling System", accessed March 12, 2020, available at: https://www.homeadvisor.com/cost/heating-and-cooling/install-a-geothermal-heating-or-cooling-system/#expectancy-energy

2. Maintenance Costs

This analysis assumes an average annual maintenance cost of approximately $100 for residential heat pumps and $143 for residential fuel furnaces and boilers[29] and represents periodic service visits and associated equipment testing and cleaning and occasional replacement parts. The costs are scaled similarly to capital costs for the representative commercial building analysis.

3. Delivered Commodity Cost Assumptions

Calculating annualized heating costs also requires an estimate of "fuel" costs for both traditional and decarbonized heating fuels. Fuel costs in turn include a "commodity" and a "delivery" component.

For the traditional heating fuels – natural gas, oil, and propane – estimates of delivered residential prices for 2020-2050 were obtained from the U.S. Energy Administration's Annual Energy Outlook (AEO 2019).[30] The AEO's Henry Hub spot price forecast[31] was used to estimate the commodity cost of natural gas. The AEO 2019 industrial propane price forecast was used to project the commodity cost of propane, and the heating oil 2019 average commodity price[32] was used to estimate the commodity cost of oil. Delivery cost estimates were derived by subtracting the commodity cost from the delivered prices. The delivery cost was then assumed to remain identical for renewable oil. For renewable gas, the delivery cost was also assumed to remain the same, though in addition, a sensitivity analysis was performed to estimate how per-unit delivery costs may change with changes in delivered volume.

a. Renewable Gas Price Assumptions

Renewable gas can be sourced from both biological feed stocks (e.g., animal waste, food waste, wastewater, waste biomass, and various energy crops) or synthetically via Power2Gas (P2G) technologies.

The amount of available (lower cost) biological feed stocks is very likely quite limited relative to current natural gas demand. For example, a study commissioned by the American Gas Foundation finds that, in its "high resource potential" scenario, a total of 4,510 trillion Btu of renewable gas could be produced annually by 2040, of which approximately 2,200 trillion Btu could be produced at a cost below $20/MMBtu (and of which approximately 700 trillion Btu are assumed to be produced via P2G). In the low resource potential scenario, the total potential renewable gas production (without P2G) is close to 1,500 trillion Btu.[33] This contrasts with reported total U.S. natural gas consumption of 15,850 trillion Btu per year on average between 2009 and 2018.[34] Hence, the total renewable gas potential by 2040 is estimated to represent between 9% (low resource potential) and 28% (high resource potential, including 5% from P2G) of total natural gas consumption. In addition, the approximately 2,200 trillion Btu estimated to be producible at a cost below $20/MMBtu represents only 14% of total natural gas demand and less than

[29] NYSERDA, "New Efficiency: New York. Analysis of Residential Heat Pump Potential and Economics. Final Report," January 2019, Section 6.6.

[30] U.S. EIA, Annual Energy Outlook 2019, Table 3 – Energy Prices by Sector and Source, released January 2019.

[31] U.S. EIA, Annual Energy Outlook 2019, Table 13 – Natural Gas Supply, Disposition, and Prices, released January 2019.

[32] For Heating Oil #2 (CME-NYMEX). Obtained from S&P Global Market Intelligence.

[33] See American Gas Foundation, Renewable Sources of Natural Gas, December 2019, pages 2, 60.

[34] Ibid, p. 11.

half of residential natural gas demand. Consequently, even if natural gas demand in the electricity sector declined significantly, the ability to produce renewable gas from sources other than P2G is limited and could only meet a modest fraction of the remaining natural gas demand.

Other studies have come to similar conclusions. For example, the California Energy Commission commissioned E3 to investigate the role of natural gas in California's low-carbon energy future. As part of its analysis, E3 estimated the available supply of renewable gas from various sources, assuming a proportional share of renewable gas production would be available to California. As shown in **Figure 11** below, potential biomethane supply (the green portion of the supply curve, i.e., renewable gas from biological feed stocks) is estimated to cover only about half or less of 2050 estimated California gas demand, and less than a quarter of 2017 demand.

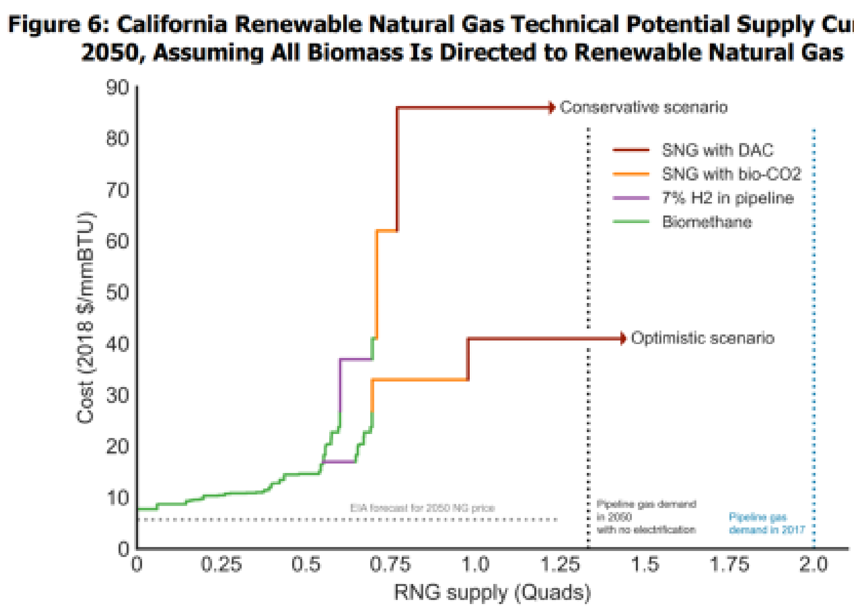


FIGURE 11: **REPRODUCTION OF E3'S RENEWABLE GAS SUPPLY CURVE FOR CEC**

Source: Reproduced from Figure 6, "The Challenge of Retail Gas in California's Low-Carbon Future," Final Project Report, California Energy Commission, CEC-500-2019-055-F, December 2019, p. 25, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf

For this reason, the analysis assumes that the marginal supply setting the price of renewable gas will be from P2G. The commodity price of renewable gas was estimated by modeling the multiple cost components of the P2G production process across a range of sensitivities, as shown in **Figure 12**.

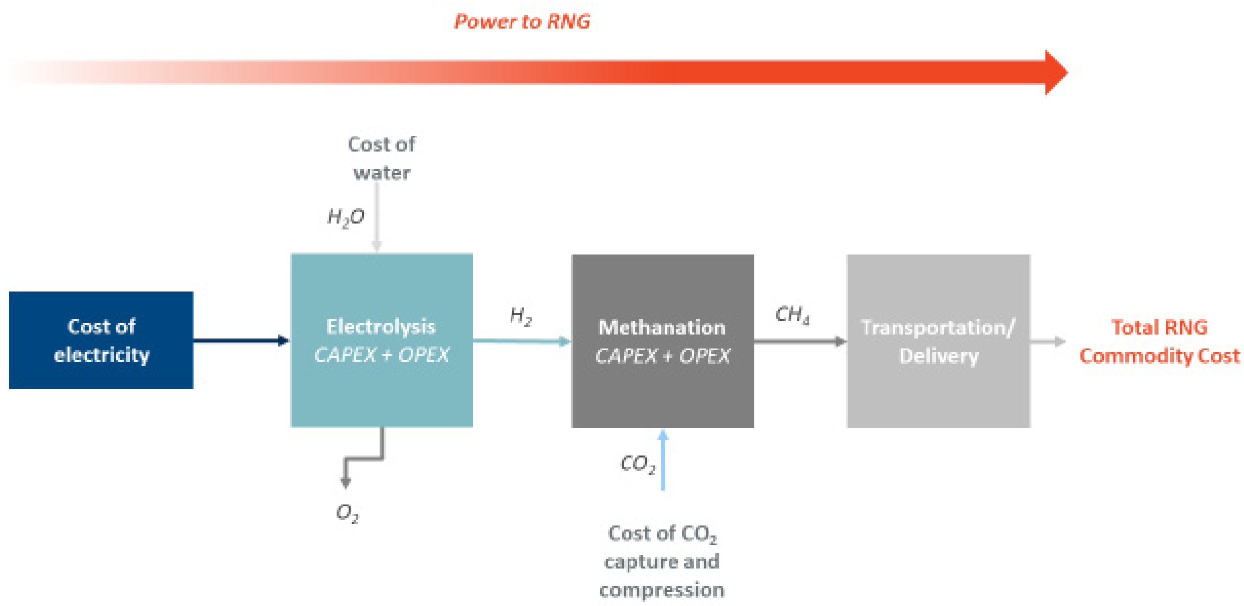


FIGURE 12: MODELED PRODUCTION PROCESS OF RENEWABLE GAS, VIA P2G

The calculation of future costs of P2G requires estimates of capital costs for electrolysis and methanation as well as operating costs, including prominently the cost of electricity, CO_2, and water as well as various other operating expenses of equipment and transport and delivery costs. Given that the P2G industry is still in its infancy, there is no reliable empirical basis for estimating P2G costs in 2050. Rather, the analysis relies on estimated costs across a number of studies.

Table 4 below summarizes the key input assumptions of the model for the high and low P2G production cost cases. The assumptions are based on the range of assumptions made in the following reports and studies on the potential cost of P2G:

- Agora Energiewende, "The Future Cost of Electricity-Based Synthetic Fuels," September 2018.
- ENEA Consulting, "The Potential of Power-to-Gas. Technology Review and Economic Potential Assessment," January 2016.
- Navigant Consulting, "Gas for Climate. The Optimal Role for Gas in a Net-Zero Emissions Energy System," March 2019.

		Low Cost	High Cost
Electrolysis			
2020 CAPEX	$/kW$_{el}$	$800	$1,000
OPEX	% of CAPEX	1%	3%
Lifetime	years	25	20
Expected Full-load Hours	hours/year	4,000	3,000
Average Annual CAPEX Decline	%	1.5%	3.0%
2020 Efficiency	%	70%	56%
Annual Efficiency Increase	%	0.5%	0.5%
Discount Rate	%	6%	6%
Methanation			
2020 CAPEX	$/kW$_{CH4}$	$700	$1,200
OPEX	% of CAPEX	5%	8%
Lifetime	Years	25	20
Expected Full-load Hours	hours/year	5,500	4,000
Average Annual CAPEX Decline	%	1.5%	1.5%
2020 Efficiency	%	80%	80%
Annual Efficiency Increase	%	0.2%	0.1%
Discount Rate	%	6%	6%
Other			
Transport & Delivery Cost	$/MMBtu$_{CH4}$	2.8	2.8
Cost of Power			
2020	$/kWh$_{el}$	0.030	0.060
2030	$/kWh$_{el}$	0.025	0.055
2050	$/kWh$_{el}$	0.020	0.050
Cost of CO_2	ct/kWh$_{CH4}$	0.7	2.8
CO_2 Annual Cost Decline	%	2.3%	1.3%
Storage Cost for Hydrogen	ct/kWh$_{CH4}$	0.55	0.55

TABLE 4: INPUT ASSUMPTIONS FOR P2G PRODUCTION COST MODEL

Since the cost of P2G depends critically on the cost of the major input, electricity, and the utilization rate of capital equipment, the analysis further tested the sensitivity of P2G costs to these inputs. At the low end, an electricity price of zero represents the ability to take advantage of renewable electricity that would otherwise be curtailed. At the higher end, the electricity price represents a projected average cost of renewable electricity (by 2050) from wind, solar, or a combination of both (potentially with battery storage). It is likely that the number of hours during which surplus renewable electricity will be available will be limited. Hence, the combination of very low electricity prices and high operating hours is less likely to occur. Increasing operating hours would likely lead to higher electricity costs as electricity would have to be purchased when prices are positive. **Figure 13** below shows the range of resulting P2G prices. It is important to note that all inputs of the P2G production process remain highly uncertain.

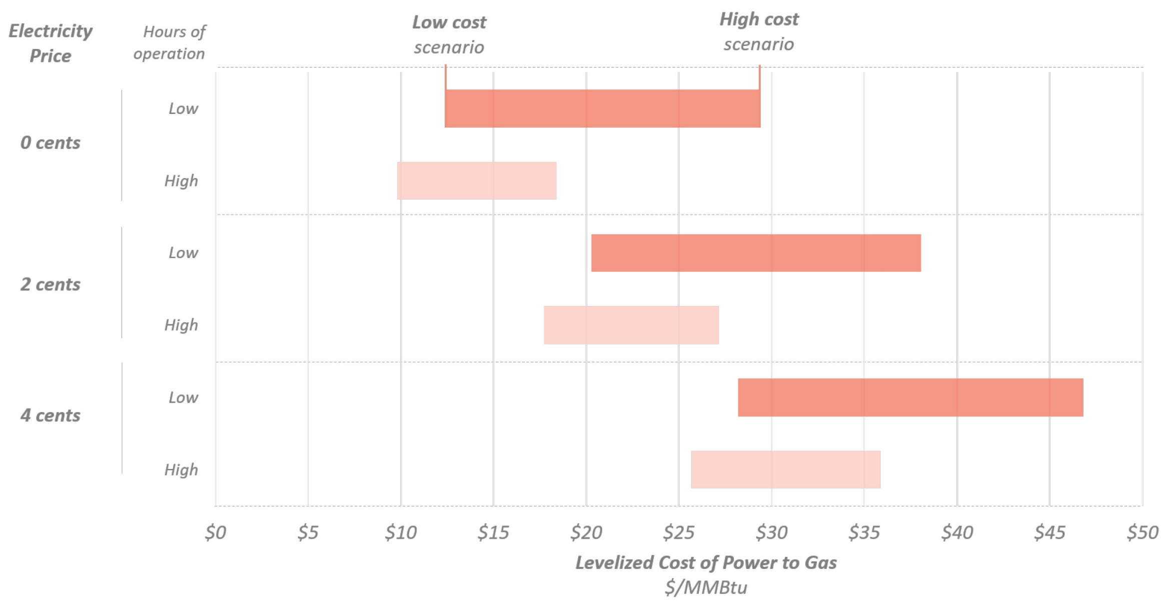


FIGURE 13: LEVELIZED COST OF POWER2GAS VARYING ELECTRICITY PRICE AND HOURS OF OPERATION

Source and Notes: Based on The Brattle Group P2G Cost Estimator; Hours of operation are 8,000 hours/yr (high) and 3,000–7,000 hours/yr (low).

These estimates do not necessarily assume that P2G is produced in New England. Rather, it could be produced where renewable electricity is cheapest and then transported via existing pipeline infrastructure.

Recognizing the tremendous range of uncertainty concerning essentially all inputs (including particularly the projections of cost declines for the major equipment involved, which in turn depends on how quickly "learning" and scaling occurs), the analysis uses a commodity price of $10/MMBtu in the low-cost scenario and $47/MMBtu in the high-cost scenario. $30/MMBtu was used as the "base case" – although this "base case" value is not assumed to be more likely than any other value in the range.

It should be noted that the P2G range overlaps with the alternative feed stocks for renewable gas discussed above, as illustrated in **Figure 14** below. The figure also includes the range of P2G costs modeled by other recent studies, notably the E3 Study commissioned by the California Energy Commission, also summarized in more detail in **Figure 11** above. Also, the low-cost case is significantly below the low end of P2G cost assumptions developed by E3. However, while the low end of the projected P2G 2050 cost range does include aggressive assumptions about the speed and rate of achievable cost declines, similar speeds and rates have been observed in other industries over the past decades, including solar PV and battery storage. Given that P2G (and more broadly, P2Fuel) are likely critical decarbonization technologies for sectors other than (but perhaps including) heating, the low P2G cost assumption therefore reflects the potential of similarly deep cost declines.[35]

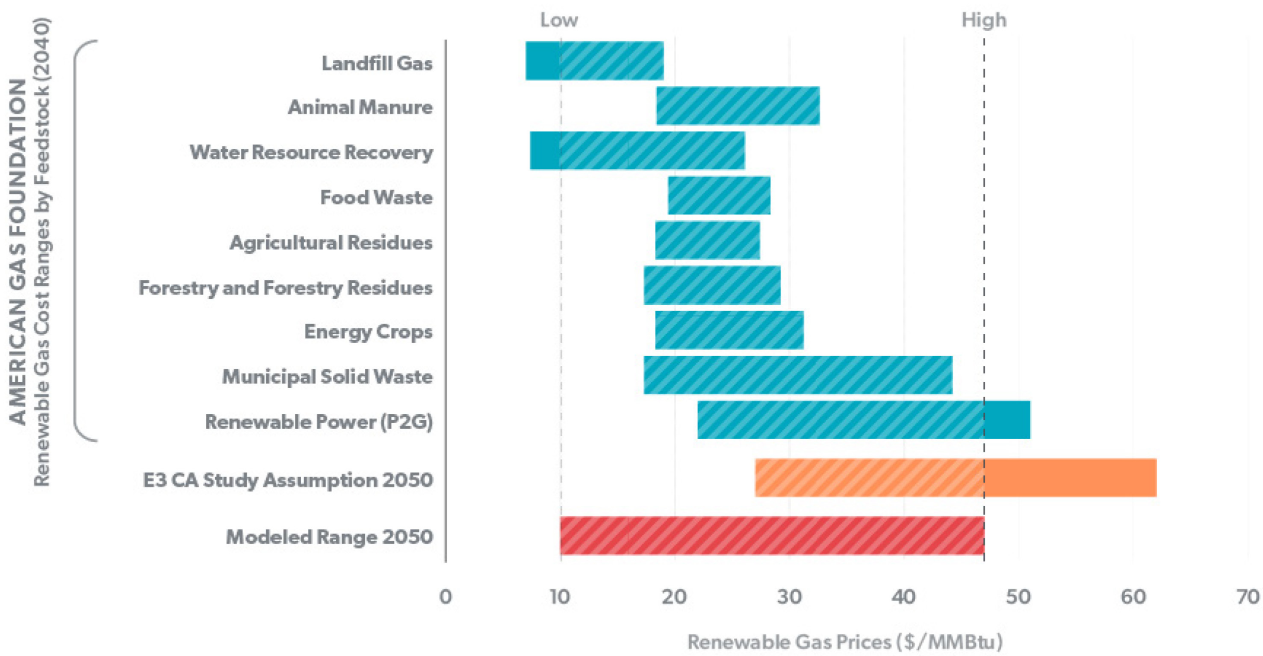


FIGURE 14: ALTERNATIVE COST ESTIMATES OF RENEWABLE GAS

Sources: American Gas Foundation, Renewable Sources of Natural Gas, December 2019, E3. Future of Natural Gas Distribution in California, December 2019.

b. Renewable Oil Price Assumptions

No separate model was developed to project the cost of renewable oil. However, as with renewable gas, it was assumed that the price of renewable oil would be driven by P2L since biological (and potentially lower cost) feed stocks will be insufficient to meet future demand for renewable liquid fuels, which will include demand from sectors other than heating, such as transportation (air, ships, potentially trains, heavy-duty road) and perhaps certain industrial applications.

P2L cost projections are also highly uncertain. They depend on long-term forecasts of the cost of renewable electricity as well as the evolution of capital costs for technologies that are still in the early stages of commercial development. Based on the range of P2L cost estimates presented in various

35 For a good discussion of the prospects of P2G, including potential 85% cost declines relative to present costs, see https://www.powermag.com/why-power-to-gas-may-flourish-in-a-renewables-heavy-world/.

publications,[36] the heating cost analysis assumes a cost of P2L of $5/gallon (corresponding to $1.25/liter, at the low end of the P2L cost projections).[37]

Figure 15 shows the resulting estimates of the range of potential 2050 delivered costs of renewable gas and renewable oil, each compared to their current fossil fuel equivalent.

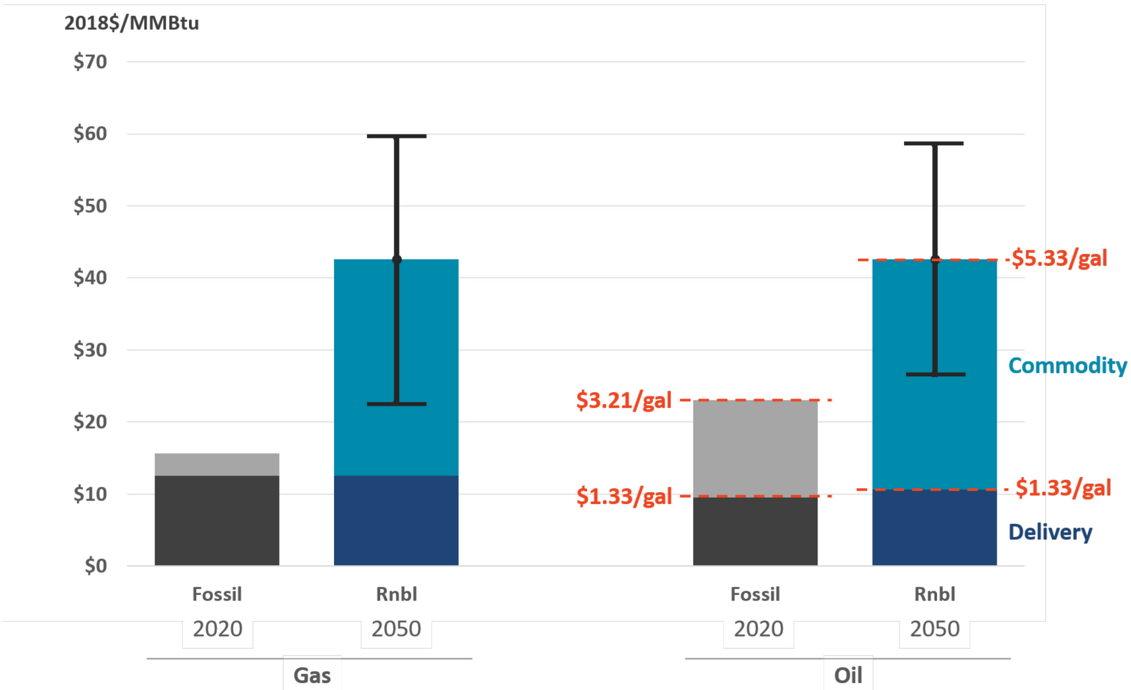


FIGURE 15: COMPARISON OF 2020 FOSSIL TO 2050 RENEWABLE FUEL PRICE PROJECTIONS

Note: Assumes 10% less energy per volume for renewable oil, relative to fossil heating oil.

As can be seen, relative to today, when natural gas has a significant cost advantage over liquid fuels, the 2050 prices of renewable gas and renewable oil are much more closely aligned. This is because the analysis assumes that the price of either renewable fuel will be set by a P2Fuels supply, which is generally similar for both renewable gas and renewable oil (with renewable oil requiring an additional transformation step).

36 See for example Ralph Uwe Dietrich, "Synthetic jet fuel from renewable energy sources for sustainable aviation," 6th International Conference on Petroleum Engineering, June 29–30, 2017, Madrid, Spain; Mahdi Fasihi, et al., Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants, Energy Procedia 99 (2016) 243 – 268, which estimates the cost of P2L at $135/barrel of oil equivalent, or roughly 2.7 times the current oil price of approximately $50/barrel. Since a barrel contains 42 gallons, a crude oil price of $50/barrel translates into a diesel price of $1.20/gallon (ignoring different energy content). Since current diesel prices are approximately $2.75/gallon, delivered diesel prices include an implied delivery charge of $1.55/gallon. A cost of $135/barrel of P2G biodiesel implies a commodity cost of $3.21/gallon. Including the implied delivery cost of $1.55/gallon would result in a delivered P2G diesel price of $4.76/gallon, close to the $5/gallon assumed in this report. See also Fasihi et al, Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants, Energy Procedia 99 (2016) 243–268.

37 See Ralph Uwe Dietrich, "Synthetic jet fuel from renewable energy sources for sustainable aviation," 6th International Conference on Petroleum Engineering, June 29–30, 2017, Madrid, Spain, p. 25–27.

c. Electricity Price

Like other fuel costs, delivered electricity prices consist of two components: commodity (generation) and delivery (transmission and distribution) costs. The development of each of these components is explained below.

Generation costs are based on The Brattle Group's DEEP Model,[38] which develops a clean power supply portfolio to meet economy-wide decarbonization targets, and estimates the total annual cost of the power supply portfolio. DEEP reflects the evolution of electricity demand, particularly in characterizing new electrification loads that result from decarbonizing the transportation and heating sectors via electrification. DEEP is used here to characterize the New England electric system under 2050 economy-wide decarbonization targets, applying similar electrification assumptions across all of New England. DEEP is used to develop several scenarios reflecting different degrees of GSHP and ASHP adoption. In all these heating scenarios, transportation is assumed to be mostly electrified (90% of light-duty vehicles (LDV) and 80% of medium (MDV) and heavy-duty vehicles (HDV). An hourly charging profile was used for each vehicle class (LDV, MDV, and HDV) to characterize the electricity demand from transportation.[39] The "baseline" electricity consumption (and its hourly shape) is assumed to benefit from continuing efficiency improvements, leading to a total decline in baseline electricity demand of approximately 13% by 2050.

To construct the "book-end" scenarios, three DEEP demand scenarios were developed, assuming (i) 100% ASHP heating across New England, (ii) 100% GSHP, and (iii) no electric heating in New England. The fourth scenario, the Mixed Scenario (which characterizes a mix of heating solutions), was based on the electrification of one-third of New England heat with ASHPs, another third with GSHPs, and the final third being supplied by (renewable) fuel. For each of these four scenarios, DEEP was then used to develop a clean generation portfolio and estimate the average cost of electricity with that portfolio.

For each of these scenarios, DEEP was used to develop a power supply portfolio that would meet the hourly load profile of the scenario. DEEP begins with nuclear and hydro generation, allocating the hourly output of these. [40] The generation portfolio was developed by beginning with a set of fixed capacity ratios for renewable generation types – land-based wind (3%), offshore wind (24%), and solar (59%) – as well as short-term storage (15%), with each type of renewable generation assigned an hourly generation profile based on data from NREL. The total renewable/storage portfolio was scaled so that its total generation (MWh) would be sufficient to meet the total annual load of that scenario, after accounting for nuclear

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[38] DEEP was used to develop "Achieving 80% GHG Reduction in New England by 2050," prepared for the Coalition for Community Solar Access by The Brattle Group, September 2019. A detailed description of DEEP and underlying assumptions are contained in the technical support document to that report. Both documents are available at: https://www.brattle.com/news-and-knowledge/news/brattle-study-achieving-new-englands-ambitious-2050-greenhouse-gas-reduction-goals-will-require-keeping-the-foot-on-the-clean-energy-deployment-accelerator.

[39] For more detail, see "Achieving 80% GHG Reduction in New England by 2050," Technical Appendix, pages 23–24.

[40] All existing New England nuclear plants will reach the end of their current license lives by 2050 (Millstone 2 and 3 in 2035 and 2045, respectively, and Seabrook 1 in 2050). This analysis assumes that Millstone 2 and 3 are retired by 2050, but that Seabrook 1's license is extended beyond 2050. Hydro consists of existing resources plus some assumed new hydro imports from Canada. This hydro energy is assigned according to monthly hydro generation profiles, allocating on average 30% of the energy in a flat hourly shape, and the remaining flexible hydro in a heuristic hourly shape within the month to roughly match load. Additional imports and exports are not characterized beyond the Canadian hydro imports.

and hydro generation. Of course, the hourly output profile of the intermittent renewable generation in this initial portfolio does not match the profile of hourly load. To accommodate this, DEEP simulates the charging and discharging of the short-term storage in the portfolio to improve the match between generation and load, to the extent this is possible. This will still fall short of fully matching generation with load, so DEEP determines how much additional clean thermal generating capacity (a mix of CC and CT resources, fired by renewable gas or renewable oil) is needed to close this remaining gap, and also provide the necessary planning reserve margins.

Because of how this portfolio is constructed, although a large amount of thermal capacity is necessary, it has very low utilization (providing less than 5% of total energy).[41] The system thus characterized – the load with the generating portfolio developed – is broadly feasible (at the level of detail characterized here), though the resulting generation portfolio is not optimized. That is, there may be a different, less costly mix of resources that would meet the scenario's load equally well. The supply portfolios developed using the methodology outlined above are summarized in **Table 5.**

		2050			
	2018 Actual	**No Electrified Heat**	**Mixed Portfolio**	**100% GSHP**	**100% ASHP**
Total and Peak Load					
Annual Load (TWh)	121	210	229	234	242
Peak Demand (MW)	25,547	35,377	44,703	44,440	72,992
Load Factor (%)	54%	68%	58%	60%	38%
Capacity (GW)					
Solar		93.4	102.0	104.2	107.8
Onshore Wind		4.0	4.3	4.5	4.6
Offshore Wind		37.8	41.3	42.2	43.6
Storage		24.1	26.3	26.9	27.8
Gas		27.9	28.4	35.7	64.0

TABLE 5: DEEP ELECTRIC LOAD AND SUPPLY PORTFOLIOS BY SCENARIO

Given this feasible generation portfolio for a particular scenario, the total annualized capital and fixed O&M costs of all the resources in the portfolio was estimated, as well as the variable O&M and fuel costs

41 Additional information on DEEP is available at: "Achieving 80% GHG Reduction in New England by 2050: Technical Appendix." https://brattlefiles.blob.core.windows.net/files/17245_achieving_80_percent_ghg_reduction_in_new_england_by_2050_technical_appendix.pdf

of the renewable thermal resources, to develop the overall cost of the generating portfolio. **Table 6** below summarizes the costs used for the renewable resources, and **Table 7** summarizes the cost and performance parameters of the renewable thermal resources. Once the total annual cost is developed, it was divided by the total annual load of the scenario to express cost on a unit basis, in ₵/kWh of generation cost.

	CAPEX 2018$/kW	Lifetime Years	Discount Rate %	FOM 2018$/kW/yr
Solar	$860	30	7%	$22.46
Onshore Wind	$1,200	20	7%	$48.42
Offshore Wind	$2,800	20	7%	$80.14
Storage	$850	10	7%	$36.32

TABLE 6: RENEWABLES AND STORAGE CAPITAL COST AND FOM CALCULATION INPUTS

Source: Capital Cost (CAPEX) based on average costs from 2020 to 2050 from NREL Annual Technology Baseline (ATB) 2019 cost database. Fixed O&M (FOM) from EIA, Cost and Performance Characteristics of New Generating Technologies, Annual, Energy Outlook 2019.

	CONE 2018$/kW/mo	Heat Rate Btu/kWh	Rnbl Gas Price $/MMBtu	FOM 2018$/kW/yr	VOM 2018$/MWh
CC	$9.42	6,546	$31	$56.65	$3.64
CT	$7.58	9,220	$31	$40.08	$4.68
Average	$8.50	7,883	$31	$48.36	$4.16

TABLE 7: GAS PLANT COST CALCULATION INPUTS

Note: Assuming 50/50 split between CCs and CTs. Sources: Cost of New Entry (CONE), heat rates, Fixed Operating and Maintenance Cost (FOM), and Variable Operating and Maintenance Cost (VOM): Concentric Energy Advisors, "ISO-NE CONE and ORTP Analysis," December 2, 2016. Renewable gas price is consistent with base case renewable gas assumption used in this study: $30/MMBtu (commodity cost) + $1/MMBtu (pipeline delivery cost).

The electricity system delivery (T&D) cost for each of the scenarios modeled begins with the embedded cost of the existing system, assuming that this system could continue to deliver the same level of service at approximately the same cost into the future. Of course, the existing T&D system would be unable to accommodate the higher peak loads of the four scenarios, which are driven primarily by the additional electrification loads. The incremental T&D capacity required for each scenario was estimated, accounting for changes in both the summer peak and the winter peak, as well as the fact that the T&D system can carry 20–25% more power in winter because of lower ambient temperatures. The cost of this incremental T&D capacity is not well understood for large increases in capacity; this was estimated based on National Grid's 2018 AESC and its embedded costs.[42] **Table 8** summarizes the calculation of the T&D cost impact of the four scenarios.

[42] National Grid provided its 2018 Avoided Energy Supply Components cost of $83.26/kW-year; this cost is used to estimate the benefits of avoided distribution costs from efficiency and demand reduction programs, which involve small changes to the T&D system. National Grid judged that the additional distribution costs associated with a large increase in system peak would be "significantly higher" than the AESC. The AESC is well below National Grid's embedded distribution cost, estimated at $291/kW-year. (The embedded cost estimate is based on estimated 2018 total distribution charges, from 2018 load and the 34% share of National Grid's Rhode Island's customer costs accounted for by distribution from EEI's Typical Bills Book, allocated on a per kW-year basis.) The midpoint of the AESC value and the estimated embedded cost was used to estimate the cost for incremental distribution system capacity. Similar information was not available for transmission cost, which was assumed to be affected in proportionally the same way as distribution costs. To estimate the Low and High ends of the uncertainty range on electricity price, the AESC and the embedded cost values were used, respectively.

	2018 Actual	2050			
		No Electrified Heat	Mixed Portfolio	100% GSHP	100% ASHP
Total and Peak Load					
Annual Load (TWh)	121	210	229	234	242
Peak Demand (MW)	25,547	35,377	44,703	44,440	72,992
Load Factor (%)	54%	68%	58%	60%	38%
T&D Multiplier Calculation					
Winter/Summer Peak?	Summer	Summer	Winter	Winter	Winter
T&D Peak Demand (MW)*	25,547	35,377	36,492	36,277	59,585
T&D Peak Demand Diff. (MW)**	n.a.	11,796	13,134	12,877	40,846
Incremental Distribution Cost ($B/yr)					
High ($291/kW-yr)	n.a.	$3.4	$3.8	$3.7	$11.9
Med ($187/kW-yr)	n.a.	$2.2	$2.5	$2.4	$7.7
Low ($83.26/kW-yr)	n.a.	$1.0	$1.1	$1.1	$3.4
Total Dist'n Cost ($B/yr)					
High	n.a.	$10.8	$11.2	$11.1	$19.3
Med	$7.4	$9.6	$9.9	$9.8	$15.1
Low	n.a.	$8.4	$8.5	$8.5	$10.8
T&D Multiplier (on embedded total T&D cost)					
High	n.a.	1.46	1.51	1.50	2.60
Med	1.00	1.30	1.33	1.32	2.03
Low	n.a.	1.13	1.15	1.14	1.46

TABLE 8: T&D COST IMPACT CALCULATION, BY SCENARIO

Source: 2050 scenario characterization from the DEEP model; 2018 values from ISO NE.

Notes: *If winter peaking, Dist'n Peak Demand = Peak Demand / (1 + 22.5%), based on the estimated 20–25% increase in distribution capacity during the winter season relative to summer, from National Grid. **Dist'n Peak Dmd Diff. = (2050 Dist'n Peak Dmd – 2018 Dist'n Peak Dmd) * (1 + 20%), to include 20% capacity margin. Incremental Dist'n Cost = Dist'n Peak Dmd Diff. x Incremental Dist'n Cost ($/kW-yr). Total Dist'n Cost =2018 Dist'n Cost + Incremental Dist'n Cost. T&D Multiplier = Total Dist'n Cost / 2018 Dist'n Cost.

Table 9 below summarizes the components and total for electricity price in the various decarbonized 2050 scenarios, alongside the 2018 total price.

	2018 Actual	2050			
		No Electrified Heat	Mixed Portfolio	100% GSHP	100% ASHP
Total Generation Costs	9.58	17.15	17.14	17.60	19.51
RE Portfolio	n.a.	12.41	12.41	12.41	12.41
CAPEX	n.a.	9.46	9.46	9.46	9.46
FOM	n.a.	2.95	2.95	2.95	2.95
Gas Portfolio	n.a.	2.78	2.77	3.23	5.14
CAPEX	n.a.	1.36	1.27	1.56	2.70
FOM	n.a.	0.64	0.60	0.74	1.28
VOM	n.a.	0.01	0.02	0.02	0.02
Fuel (Renewable Gas)	n.a.	0.76	0.89	0.92	1.15
Other Generation Costs	1.96	1.96	1.96	1.96	1.96
Total Transmission Costs	2.43	1.82	1.71	1.67	2.47
Total Distribution Costs	6.13	4.60	4.33	4.21	6.23
Total Electricity Price	18.14	23.57	23.18	23.49	28.22

TABLE 9: ELECTRICITY PRICE BREAKDOWN BY SCENARIO (CENTS/KWH)

4. Carbon Cost

To allow for a better comparison of fossil with decarbonized heating options, the annualized cost analysis also includes the assumed cost of carbon emissions. The analysis uses a cost of $75/metric ton, in line with current benefit-cost analyses performed by the state.[43] This cost is applied to the net GHGs from the

[43] A carbon value of $75/metric ton ($68/short ton) is used currently as the avoided carbon value in evaluating Rhode Island's energy efficiency programs. Synapse Energy Economics, "Avoided Energy Supply Components in New England: 2018 Report," prepared for AESC 2018 Study Group, originally released March 30, 2018 (amended October 24, 2018), available at:

combustion of fuel (assumed to be zero for the renewable fuel options, which implies that the fuel would be carbon neutral, though that may not always be the case today), and also the GHG contribution of methane leaks (at the current leak rate).[44]

Renewable gas includes the leak component as well, since even if the source gas itself is carbon-neutral when combusted, methane leaks still create GHG emissions; methane is a much more potent greenhouse gas than CO_2. The analysis assumes a 100-year global warming potential for methane of 30; alternatively, a 20-year GWP of 85; current leak rates are estimated at 2.7%.[45] It is necessary to adjust for the different masses of methane and CO_2. GWPs are expressed per ton of gas, and one ton of methane accounts for 2.75 tons of CO_2, based on the ratio of the molar masses of methane (16) and CO_2 (44). Thus, using a 100-year GWP of 30, a 2.7% leak rate, and a mass conversion of 16/44, the additional GHGs contributed by leaks can be calculated as:

> 2.7% Leak Rate * (16/44) tons methane/ton CO_2 * 30 GWP = +29.5% of the combustion CO_2.

This suggests that methane leaks from the distribution system can add roughly 30%–85% to the GHG of the CO_2 in the combustion products, based on a 100-year or 20-year GWP for methane. Gas leaks have already been reduced in recent years throughout the natural gas supply chain. In the distribution system, "The decrease in distribution emissions is largely attributed to increased use of plastic piping, which has lower emissions than other pipe materials, and station upgrades at metering and regulating (M&R) stations."[46] Successful efforts to further reduce leaks would reduce the GHG contribution and social costs of methane leaks correspondingly.

D. ENERGY WALLET

To compare overall energy expenditures in a decarbonized future, in the context of the alternative decarbonized heating solutions, the analysis began with the heating costs of the various solutions from

http://rieermc.ri.gov/wp-content/uploads/2019/04/aesc-2018-17-080-oct-rerelease.pdf. For purposes of this analysis, the same value is used for 2050 comparisons even though, as described above, the value of avoided carbon emissions is likely to increase as reflected in rising values of the social cost of carbon over time.

44 Natural gas leak rates are estimated at 2.7% by "Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study," September 2019, Stockholm Environment Institute, et al. See also Kathryn McKain, et al., "Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts," *Proceedings of the National Academy of Sciences* 112, no. 7 (2015): 1941–1946, at: https://www.pnas.org/content/pnas/112/7/1941.full.pdf.

45 Based on the EPA range of 28–36 for the 100-year GWP of methane, and 84–87 for the 20-year GWP. EPA, "Understanding Global Warming Potentials," available at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials. This is consistent with IPCC estimates of methane's GWP (IPCC, Fifth Assessment Report, Chapter 8: Anthropogenic and Natural Radiative Forcing, p. 714, Table 8.7).

46 U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2016," p. 2–16.

the economic model, and added the cost of personal vehicle fuels (gasoline in 2020 or electricity in 2050, excluding vehicle cost), as well as the cost of electricity for today's traditional "baseline" uses. Energy wallet costs for 2020 were evaluated using the current electricity price (for baseline electricity use) and the 2018 average Rhode Island gasoline price as a proxy for 2020 for transportation costs.[47] Costs in 2050 were based on the electricity price that results in the Mixed Scenario, for both baseline and transportation (EV charging). Baseline electricity consumption, excluding space heating and transportation, used the average monthly electricity consumption of 589 kWh per customer in Rhode Island.[48] Vehicle miles traveled were 17,400 per household per year[49]; vehicle efficiency is assumed to be 3.5 miles per kWh for 2050 electric vehicles (with 15% charging losses),[50] and 25.1 miles per gallon for in 2020 internal combustion engine vehicles.[51]

E. COST SENSITIVITY ANALYSIS

High- and Low-cost scenarios on the total economic cost of heating were examined, illustrated in Figures 23, 24, 26, 27, and 28 of the Report. These reflect plausible high and low-cost estimates based on reasonable estimates of the uncertainty in future installed cost for equipment (heat pumps), and uncertainty in the price of renewable fuels and electricity.

For these, several parameters that affect costs in the scenarios were varied to reflect the range of plausible values. The high and low parameter values on these dimensions are presented in **Figure 9** below. The outer limits of the uncertainty ranges that are illustrated by the uncertainty bars in Figures 23, 24, 26, 27, and 28 of the Report are determined by simultaneously moving all the relevant parameters to their respective High or Low values.

The high and low electricity price estimates reflect a +20% (high) to -20% (low) change in the generation component. These also reflect the cost estimates of the transmission and distribution system, with required T&D expansions to meet increased load evaluated at National Grid's approximate embedded T&D cost of $291/kW-year (high case), at National Grid's Avoided Energy Supply Components value of $83.26/kW-year (low case), and at the midpoint of the two ($187/kW-

47 U.S. Energy Information Administration, Motor gasoline consumption, price, and expenditure estimates, 2018. https://www.eia.gov/state/seds/sep_fuel/html/pdf/fuel_mg.pdf

48 EIA, 2018 Average Monthly Bill – Residential.

49 Federal Highway Administration (FHA) data reports 8 billion vehicle miles traveled in Rhode Island, at: https://www.fhwa.dot.gov/policyinformation/statistics/2018/vm2.cfm. Approximately 89% of total miles driven in the U.S. correspond to light-duty vehicles, according to the FHA data, at: https://www.fhwa.dot.gov/policyinformation/statistics/2018/vm1.cfm. This is equivalent to approximately 7.2 billion vehicle miles in Rhode Island. Buro Happold Engineering's building stock model shows 412,000 residential households in Rhode Island, yielding approximately 17,400 VMT per household.

50 National Renewable Energy Laboratory, Electrification Futures Study Technology Data, 2017. Average for light-duty cars and light-duty trucks in 2050. Charging loss based on review of studies by the VEIC and the National Center for Sustainable Transportation: Vermont Energy Investment Corporation (VEIC) Transportation Efficiency Group, "An Assessment of Level 1 and Level 2 Electric Vehicle Charging Efficiency," March 20, 2013 (Revised); and National Center for Sustainable Transportation, "Exploring Electric Vehicle Battery Charging Efficiency," September 2018.

51 Based on U.S. national average fuel economy in 2018. U.S. Environmental Protection Agency, "The 2019 EPA Automotive Trends Report," available at: https://www.epa.gov/automotive-trends/download-automotive-trends-report

year) for the nominal estimate. The variation in renewable gas prices reflects the possible increase in the delivery price of natural gas due to a decrease in natural gas volumes.

	Cost Case		
	Low	**Baseline**	**High**
Electricity Price *($/kWh)**			
ASHP (Bookend)	$0.22	$0.28	$0.35
GSHP (Bookend)	$0.19	$0.23	$0.28
ASHP/GSHP *(Mixed)*	$0.19	$0.23	$0.28
Average Economic Life *(years)*			
ASHP	25	15	10
GSHP	30	20	10
Annual Cost Decline			
ASHP/GSHP	-2%	-1%	-0.5%
Renewable Gas Price *($/MMBtu)*			
Commodity	$10	$30	$47
Delivery *(Bookend)*	$13	$13	$13
Total *(Bookend)***	$23	$43	$60
Delivery *(Mixed)*	$13	$26	$39
Total *(Mixed)***	$23	$56	$86
Renewable Oil Price *($/gal)*			
Commodity	$2.00	$4.00	$6.00
Delivery	$1.33	$1.33	$1.33
Total	$3.33	$5.33	$7.33

TABLE 10: COST PARAMETERS FOR HIGH- AND LOW-COST CASES

Notes: *ASHP *(Bookend)* based on "100% ASHP Heat" scenario, GSHP *(Bookend)* based on "100% GSHP Heat" scenario, and ASHP/GSHP (Mixed) based on "Mixed Heat Portfolio" scenario. **Total = Commodity + Delivery.

IV. Water Heating

The water heating cost analysis compares the cost of a 50-gallon residential water heater powered by a range of technologies: direct fuel burning (with gas or oil, both either renewable or fossil), electric resistance, and electric heat pump. It also assumes that the annual water heating energy consumption of a single-family residential home is 15 MMBtu.[52] The water heating analysis focuses on analyzing three main types of costs: the capital cost of the water heater, the operating costs, which depend on total energy consumption and delivered fuel or electricity price, and the carbon costs associated with fuel combustion and gas methane leaks.

The annualized capital costs were estimated based on the capital cost and average economic lives of the existing technologies, summarized in **Table 11**. As in the space heating analysis, it is assumed that the installed cost of heat pumps declines at an annual rate of 1% from 2020 to 2050, which results in a reduction in installed costs of approximately 25% by 2050. The analysis assumes a (social) discount rate of 3%.

	2050 Capital Costs	Avg. Econ. Life	Efficiency
	2018$	Years	%
Gas (Renewable and Fossil)	$1,265	13	67%
Oil (Renewable and Fossil)	$2,000	13	67%
Electric Resistance	$700	13	95%
Electric Heat Pump	$1,110	10	200%

TABLE 11: WATER HEATER CAPITAL COSTS AND AVERAGE ECONOMIC LIFE

Sources: ENERGY STAR® Residential Water Heaters: Final Criteria Analysis, April 1, 2018. Gas: based on "High- Performance" gas water heater assumptions in Table 2; electric resistance: based on "High-Performing" electric water heater in Table 1; electric heat pump: based on "HPWH" electric water heater in Table 1. Oil: capital costs from Home Advisor, based on heater average cost range of $1,000 – $3,000. (https://www.homeadvisor.com/cost/plumbing/install-a-water-heater/#propane) Note: Oil-fired water heaters fall on the expensive end of the spectrum, but offer an alternative to electricity and natural gas for rural and off-grid homes.

The average water heater efficiencies were used to convert the annual water heating energy consumption for a residential single-family home, 15 MMBtu per year, into fuel or electricity demand. The water heating analysis uses the same fuel and electricity prices as in the space heating analysis, summarized in Table 12.

52 ENERGY STAR® Residential Water Heaters: Final Criteria Analysis, April 1, 2018. Buro Happold's analysis shows a similar average value for a single-family home – 17.8 MMBtu/year.

	Commodity	Delivery	Total
Gas (Fossil)	$4.9/MMBtu	$12.6/MMBtu	$17.4/MMBtu
Gas (Renewable)	$30/MMBtu	$12.6/MMBtu	$42.6/MMBtu
Oil (Fossil)	$2.8/gal	$1.3/gal	$4.1/gal
Oil (Renewable)	$4.0/gal	$1.3/gal	$5.3/gal
Electricity	16.7¢/kWh	5.9¢/kWh	22.6¢/kWh

TABLE 12: WATER HEATING DELIVERED FUEL PRICES IN 2050 (2018$)

Sources: See Section III.C.3.

The water heating analysis also uses the same carbon cost assumptions as in the space heating analysis and described in Section III.C.4: a carbon price of $75/ton, a methane leakage rate of 2.7% for fossil and renewable gas, and a methane 100-year global warming potential of 30.

V. Industrial Heat

The report highlights that solutions for decarbonizing heating in the industrial sector are likely very idiosyncratic not only based on the industry in question, but also the particular facilities involved. Information about heat use within the industrial sector is relatively incomplete. Rhode Island is not a heavily industrialized state, and the core industrial sector represents a relatively small portion of its economy. **Table 13** below provides an overview of employment in Rhode Island as of December 2019, with industrial sectors highlighted.

	Employment	of Private
Total Nonfarm	506,300	
Total Private	444,800	
Mining & Logging	200	0.04%
Construction	19,200	4.32%
Manufacturing	39,200	8.81%
Durable Goods	24,800	5.58%
Non-Durable Goods	14,400	3.24%
Trade, Transportation & Utilities	13,700	3.08%
Wholesale Trade	17,700	3.98%
Retail Trade	48,800	10.97%
Transportation & Utilties	13,700	3.08%
Information	6,200	1.39%
Financial Activities	35,900	8.07%
Finance & Insurance	28,400	6.38%
Professional & Business Services	69,500	15.63%
Professional, Scientific & Technical Services	25,400	5.71%
Management of Companies	13,300	2.99%
Administrative & Waste Services	30,800	6.92%
Education & Health Services	110,600	24.87%
Educational Services	26,200	5.89%
Health Care & Social Assistance	84,400	18.97%
Leisure & Hospitality	60,300	13.56%
Arts, Entertainment & Recreation	9,600	2.16%
Accommodation & Food Services	50,700	11.40%
Other Services	23,500	5.28%
Government	61,500	13.83%
Federal Government	11,100	2.50%
State Government	16,500	3.71%
Local Government	33,900	7.62%

TABLE 13: **EMPLOYMENT IN RHODE ISLAND BY SECTOR**

Source: RI Department of Labor and Training.

As can be seen, the vast majority of employment in the "industrial" sector is in the service sectors (which would typically be housed in commercial buildings). Activities where process heat may be required, notably certain manufacturing activities, represent about 9% of total employment. **Table 14** provides a more detailed summary of activity within the manufacturing sector.

	Employment
Durable Goods Manufacturing	
Wood product manufacturing	461
Nonmetallic mineral product manufacturing	678
Primary metal manufacturing	1,441
Machinery manufacturing	1,971
Computer and electronic product manufacturing	3,492
Electrical equipment and appliance manufacturing	1,138
Transportation equipment manufacturing	5,624
Furniture and related product manufacturing	1,174
Miscellaneous manufacturing	5,095
Total	25,787
Nondurable Goods Manufacturing	
Food manufacturing	3,193
Beverage and tobacco product manufacturing	512
Textile mills	1,874
Textile product mills	533
Apparel manufacturing	109
Leather and allied product manufacturing	104
Paper manufacturing	1,312
Printing and related support activities	1,730
Petroleum and coal products manufacturing	81
Plastics and rubber products manufacturing	2,147
Total	14,546

TABLE 14: BREAKDOWN OF EMPLOYMENT IN MANUFACTURING SECTOR

Source: RI Department of Labor and Training, Rhode Island Manufacturing Sector by Component 2018.

Very few of these sectors have potentially material demands for process heat. They include primary metal manufacturing, chemical manufacturing, food manufacturing, nonmetallic mineral product manufacturing, paper manufacturing, plastics, and rubber products manufacturing and to a lesser degree, the other industries active in Rhode Island.

For these industries, the use of heat is highly process-specific and at least some of the decarbonized heat solutions analyzed – namely heat pumps – are generally not a realistic decarbonization pathway, since heat pumps cannot provide high-temperature heat. In addition to the use of drop-in fuels such as renewable oil or gas (or hydrogen, which is an intermediate product), various electrification approaches also exist. In addition, a number of process-specific energy efficiency measures may be available to reduce the amount of energy needed for process heat requirements.[53]

Also, decarbonizing process heat via either energy efficiency measures or technology-switching, i.e., by replacing natural gas boilers with induction heating, can require the disruption of often well-established manufacturing processes, with corresponding risks. The costs associated with business interruptions or failures by a new (decarbonized) approach to deliver expected results can be significant, and thus the adoption of decarbonization strategies that involve such switching will likely face particularly high adoption hurdles.

Because process heat decarbonization is highly application-specific and because it represents a relatively small share of total heating demand in Rhode Island, this report does not present a quantitative analysis of various decarbonization options for the industrial sector(s).

[53] Efficiency improvements for both "fuel-based" and electricity-based process heating have been proposed. For electricity-based system, they include the use of induction heating, microwave and laser processing, etc. See for example U.S. Department of Energy, "Improving Process Heating System Performance: A sourcebook for industry, 2nd Edition," 2007.