Earnest White
Senior Consultant

EJW-1

Professional Summary

Earnest White brings experience focused in load forecasting, power market modeling, capacity expansion planning, and regulatory policy. His most recent experience was analyzing and providing expert witness testimony on integrated resource plans, renewable portfolio standard petitions, utility-scale solar certifications, general rate cases, and retail choice as staff member of the Virginia State Corporation Commission. Earnest has training and experience across several utility-specific planning platforms including PLEXOS, Aurora, PROMOD, and IMPLAN. Additionally, he has worked with SAS, R, and Python.

Experience

2022-present: Senior Consultant, Energy Futures Group, Hinesburg, VT

2017-2022: Principal Utilities Policy Specialist, Virginia State Corporation Commission, Richmond, VA

2014-2017: Lead Analyst Wholesale Markets, Tesla Forecast Solutions, Richmond, VA

2008-2014: Power Market Modeler, Tesla Forecast Solutions, Richmond, VA

Education

Master of Energy Business, University of Tulsa, 2021

Bachelor, Economics, Virginia Commonwealth University, 2009

Select Projects

- Virginia State Corporation Commission. Analyzed and provided expert witness testimony related to the load forecasting assumptions and capacity modeling of the 2018 and 2020 Dominion Energy Virginia IRPs. (2018-2020)
- CENACE. Supported the National Energy Control Center (CENACE) of Mexico's development and deployment of its national and regional power market forecasting. (2016-2017)
- Transpower New Zealand. Collaborated with New Zealand's national grid operator to develop new techniques to estimate and forecast the effects of distributed generation on net load at the transmission level. (2011-2017)
- Washington State Office of the Attorney General. Supported GTN Xpress Project: A Critical Review of Need, Cost and Impacts, prepared for the Washington State Office of the Attorney General, and filed with the Federal Energy Regulatory Commission in Docket No.CP22-2-00, on behalf of the States of Washington, California, and Oregon.

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nationalgrid

Aquidneck Island Long-Term Gas Capacity Study

Prepared by National Grid

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1. Introduction

As Rhode Island's only natural gas local distribution company, National Grid ("the Company") delivers natural gas to households and businesses to meet their essential energy needs. Roughly 270,000 residents and businesses across the state rely on the Company to provide them with safe, reliable, and affordable energy, especially to meet their heating needs during the coldest months of winter.

The following pages examine potential solutions specific to Aquidneck Island to address the gas capacity constraint and vulnerability needs faced by the island. National Grid realizes the gas service interruption event on Aquidneck Island in January 2019 raised the public's concern about reliability. National Grid is committed to ensuring customers on Aquidneck Island and across Rhode Island have access to the energy they need to heat their homes and keep their businesses running at all times, and the Company has at least a temporary solution in place today in the form of portable liquefied natural gas (LNG) on Aquidneck Island.

The Company believes that an effective long-term solution or solutions must consider a variety of factors. Safety and reliability are prerequisites for any solution. Meanwhile, the current economic crisis underscores the importance of cost and affordability. Environmental implications are also front-of-mind, as the Company is committed to the clean energy transition and working to meet Rhode Island's ambitious climate goals, including the decarbonization of its heating sector, as highlighted by Governor Raimondo's Executive Order 19-06 and the resulting Heating Sector Transformation recommendations issued in April 2020.

The goal of this study is to share with customers, regulators, policymakers, and other key stakeholders the forecasted long-term energy needs for Aquidneck Island and to evaluate a broad spectrum of potential solutions across key criteria. Our hope is that this study will help inform more discussions and enable us to gather feedback from a variety of stakeholders, so National Grid can then provide a recommendation for the most prudent path forward and pursue a long-term solution for Aquidneck Island.

The following pages present a wide array of options. Not every detail has been worked out at this stage of planning. Some options require further engineering or program design before their costs can be estimated with greater certainty and before they could be implemented. Some options might require major regulatory or policy changes. National Grid presents this study as a first step in a process to arrive at the best long-term solution for Aquidneck Island.

2. Executive Summary

2.1. Aquidneck Island households and businesses depend on National Grid for essential energy services. The Company must plan to meet customers' needs even on the coldest winter days when gas demand is highest

National Grid is the only natural gas distribution utility in Rhode Island. On Aquidneck Island, the Company serves roughly 13,800 residential and business customers who rely on National Grid for safe, reliable, and affordable service, especially keeping their homes and businesses heated on the coldest winter days.

In order to fulfill its obligation to provide reliable service to its gas customers across Rhode Island, National Grid plans to meet customers' gas demand during the coldest year (referred to as the "design year") and on the coldest day and hour (referred to as the "design day/hour") that the Company expects to occur with a given probability. National Grid sets its design day and other planning criteria transparently before the Rhode Island utility regulator, and the Company conducted a cost-benefit analysis that considers the costs of greater reliability against the benefits to customers from avoiding loss of gas supply in extreme cold. In Rhode Island, the design day has an average temperature of -3 degrees Fahrenheit and a likelihood of occurring approximately once in 60 years.

National Grid forecasts peak gas demand during these design conditions to ensure that it can reliably meet customers' needs. To meet these needs, the Company must have sufficient natural gas capacity and supply. Capacity refers to the ability to access natural gas when and where it is needed in sufficient quantities to meet customers' peak demand—i.e., to have the throughput needed to meet peak demand. In Rhode Island, National Grid's gas capacity portfolio consists entirely of interstate pipeline and LNG storage capacity. Gas supply refers to the actual natural gas volumes needed to meet customer demand, which the Company accesses via the natural gas capacity.

2.2. National Grid faces the prospect of intermittent restrictions on the interstate gas pipeline capacity serving Aquidneck Island, resulting in a gas capacity constraint where the forecasted peak demand for which the Company plans exceeds the amount of gas pipeline capacity that the Company can rely on to be available on the coldest winter days

Two interstate natural gas pipelines transport natural gas supplies to National Grid for distribution to Rhode Island customers. One of these two pipelines—Algonquin Gas Transmission, LLC (AGT)— is a Northeastern interstate natural gas pipeline that extends from New Jersey up into Massachusetts. The AGT G-system is a lateral that branches off the AGT mainline in southern Massachusetts and extends south and east to serve parts of Rhode Island and southeastern Massachusetts. The AGT G-system includes laterals that further branch off, and one of these provides natural gas deliveries to National Grid's Portsmouth take station (i.e., a point where an interstate pipeline connects with a gas distribution network) for distribution across Aquidneck Island. The geographic location of Aquidneck Island relative to AGT puts the island at the "end of a pipe" on the AGT G-system.

Historically, the Company had been able to exercise flexibility in how it takes natural gas from AGT at different take stations to meet customers' energy demand in different parts of the Rhode Island service territory. In the past, the Company could take more gas at one location, such as Portsmouth, and less at another so long as the total pipeline takes were within the aggregate volume limit with the pipeline across take stations.

However, demand for natural gas supplies in the Northeast has outpaced new pipeline infrastructure. As such, the interstate pipelines serving New England, including AGT, have become more constrained, and they have threatened to impose restrictions on the flexibility that they have historically afforded their customers, including National Grid. Since January 2019, National Grid no longer relies on this flexibility from AGT on the coldest days.

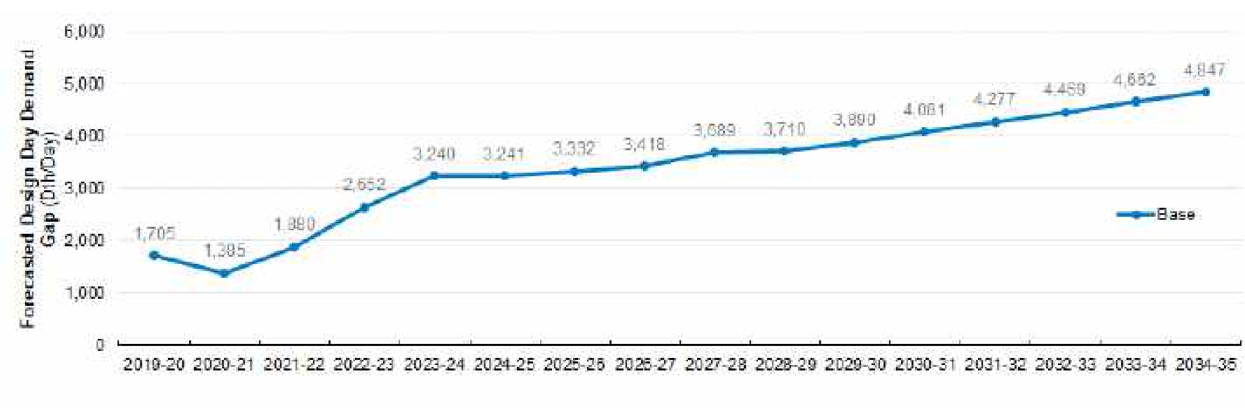
This change in approach effectively reduced the AGT capacity available to Aquidneck Island compared to the capacity available in the past. The lack of flexibility also created an immediate gas capacity constraint when projected demand is at its highest on the island under extreme cold conditions, including design day and design hour conditions.

2.3. Aquidneck faces both capacity constraint and capacity vulnerability needs

Without being able to count on having the operational flexibility with AGT that the Company had historically relied upon to meet projected peak demand under design day/hour conditions, National Grid identified a gap between the capacity available to the Company on Aquidneck Island and forecasted design day and design hour gas demand. This is the capacity constraint need that must be addressed. The gap between gas capacity and demand is only expected to occur on extremely cold days.

This need grows more severe in the future from factors such as new construction and oil-to-gas conversions on Aquidneck Island. Figure 1 shows the forecasted design day capacity constraint for Aquidneck Island based on comparing forecasted peak demand to available AGT capacity at the Portsmouth take station (not including the temporary, portable LNG on Aquidneck Island). The design day capacity constraint is projected to grow from 1,385 dekatherms per day, or Dth/day, (129 Dth/hour) for winter 2020/21 to 4,847 Dth/day (302 Dth/hour) by winter 2034/35 under the Company's base case gas demand forecast.[1] That means the capacity constraint will go from about 6% of design day demand on Aquidneck Island today to about 18% in winter 2034/35.

Figure 1: Capacity Constraint - Forecasted Gap Between Design Day Demand and Available Pipeline Gas Capacity for Aquidneck Island (Base Case Demand Forecast)



Aquidneck Island faces a second and distinct need in terms of capacity vulnerability. Even if the Company were able to match projected peak demand with available pipeline capacity after accounting for the loss of operational flexibility on AGT, there could still be unexpected upstream disruptions that would limit available pipeline capacity. Aquidneck Island has a capacity vulnerability need insofar as its position at the "end of a pipe" on the AGT G-system makes it susceptible to reductions in available capacity if there are upstream gas pipeline disturbances. Without addressing this need, such disturbances could lead to future customer service interruptions.

[1] As explained below, the Company used scenario analysis to develop three long-term gas demand forecasts—i.e., a baseline forecast and high and low sensitivities, which vary in terms of the level of underlying economic factors driving demand growth.

2.4. National Grid has taken immediate, short-term measures to address the capacity constraint and capacity vulnerability needs

National Grid mobilized a temporary portable LNG operation starting with the 2019/2020 winter season at a Company-owned site on Old Mill Lane in Portsmouth, Rhode Island. This solution was the best option to quickly address the capacity constraint and capacity vulnerability needs. The Company mobilizes this portable LNG for the duration of the winter season so that it is available, if necessary, to meet peak demand or in the event of a gas capacity disruption. It is demobilized after the end of the winter.

The temporary portable LNG operation relies on trucked LNG that can be vaporized and transferred into the Company's gas distribution network. The capacity of the portable LNG (650 Dth per hour) is sufficient to meet customers' peak gas demand on a design hour when demand exceeds the maximum capacity available to Aquidneck Island from AGT. The portable LNG also can avoid or substantially reduce customer service interruptions during the coldest conditions (and thus highest gas demand) in the face of a partial pipeline capacity disruption, depending on the severity of the disruption. This portable LNG ensures reliable service to nearly all customers on Aquidneck Island under design day conditions (i.e., -3 degrees Fahrenheit) even if there was a 50% reduction in the gas supply transported to Aquidneck Island by AGT because of an upstream disruption. Moreover, as part of the Company's commitment to having contingency gas capacity available for Aquidneck Island, the Company plans to have the portable LNG available for vaporization on days forecasted to be 20 degrees Fahrenheit or colder to provide backup gas capacity for Aquidneck Island in the event of an upstream pipeline disruption.[2] The Company's current contingency plan provides for enough LNG gas supply for two days of unexpected AGT capacity disruption.

Although National Grid stages LNG trucks at the Old Mill Lane portable LNG site when the temperature is at or below 20 degrees Fahrenheit, it has not yet had to rely on LNG vaporization for Aquidneck Island and expects to need the LNG capacity only on extremely cold days (i.e., under design day conditions, with current customer demand) or in the unlikely event of a pipeline disruption.

2.5. A long-term solution is needed for Aquidneck Island to address its capacity constraint and capacity vulnerability needs

The current temporary portable LNG solution at Old Mill Lane has advantages insofar as it addresses the capacity constraint and vulnerability needs at relatively low cost and its temporary nature provides flexibility in the midst of a clean energy transition for Rhode Island.

The temporary portable LNG at Old Mill Lane also has disadvantages in terms of its location and the legal uncertainty surrounding continued operations. The location of the Old Mill Lane portable LNG operations within the vicinity of residential neighborhoods has engendered vocal opposition from some close-by residents concerned about perceived safety and local community impacts (e.g., traffic, noise, lighting). The Company has made efforts to minimize the impact of operations on abutters and residents, including aesthetic improvements to the site and additional measures to decrease potential noise concerns. Moreover, National Grid has conducted multiple portable LNG process safety reviews to identify, quantify and manage risks

[2] On a 20-degree Fahrenheit day, the portable LNG at Old Mill Lane could supply service to all Aquidneck Island customers even if the Company lost approximately 75% of the expected supply to Aquidneck Island from the AGT pipeline due to an upstream disruption.

to employees as well as to members of the public in the nearby areas. Nonetheless, the Company is committed to looking at alternative long-term solutions that might be preferred in terms of community impacts.

In addition, the Company's legal ability to continue operating the portable LNG site at Old Mill Lane faces uncertainty. While the Company maintains that the temporary, seasonal nature of the portable LNG equipment means that it lies outside the licensing jurisdiction of the Rhode Island Energy Facilities Siting Board (EFSB), the EFSB has not yet adjudicated this legal question about its jurisdiction, and the Company presently has a two-year waiver from the EFSB to operate the portable LNG facility only through the 2020/21 heating season.

With at least a stop-gap solution that addresses the capacity constraint and vulnerability needs on Aquidneck Island for now, the circumstances call for a decision on a long-term solution to meet Aquidneck Island's needs. Having a temporary portable LNG service already in place may allow for consideration of options that have longer, multi-year implementation timelines.

2.6. A long-term solution for Aquidneck Island must support projected growth in gas demand

Any long-term solution must address the current gas capacity constraint and projected growth in energy needs on the Island. To this end, the Company has relied upon its long-term forecast of natural gas demand for Rhode Island. This forecast takes into account fundamental factors that affect gas demand (namely economic and demographic factors and energy prices).

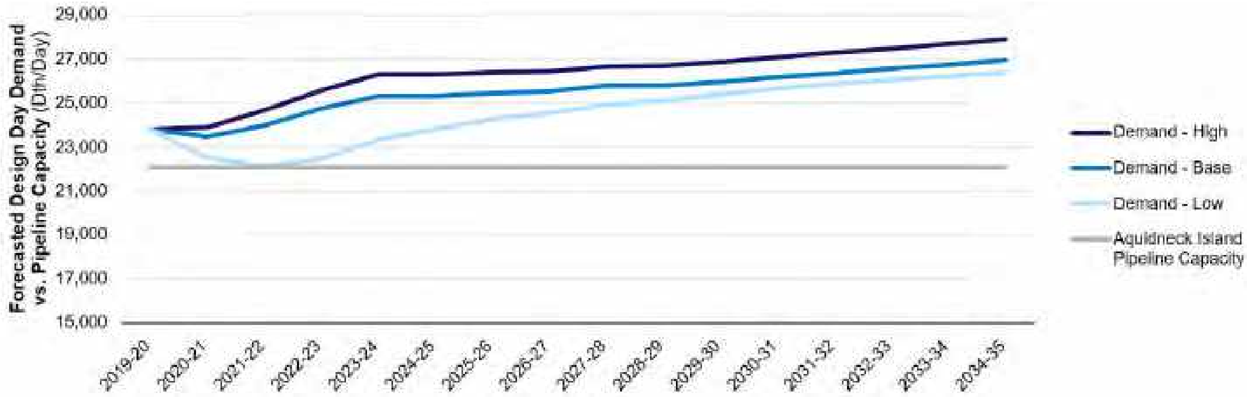
Rhode Island is a national leader in energy efficiency, ranked third in the nation in the most recent *2019 State Energy Efficiency Scorecard* report from the American Council for an Energy-Efficient Economy. The Company's long-term gas demand forecast reflects the effects of energy efficiency including assuming higher levels of savings from National Grid's future state-level gas energy efficiency programs. Taking energy efficiency into account in the forecast lowers the projected growth of gas demand over time in the Company's baseline forecast.

The Company used the historical relationship between gas demand on Aquidneck Island in relation to the rest of the state to create a long-term gas demand forecast specifically for Aquidneck Island. This study evaluates potential long-term solutions against this Aquidneck Island-specific gas demand forecast.

The Company's long-term gas demand forecast projects that peak (i.e., design day) demand on Aquidneck Island, after accounting for expected gas energy efficiency savings, will grow at a compound annual growth rate of 0.8% per year from winter 2019/20 through winter 2034/35 (with low/high economic forecast sensitivities projecting growth rates of 0.7 to 1.1% per year over the same time period).[3] This projected growth rate also reflects the anticipated economic impacts from the COVID-19 pandemic.

[3] The high/low sensitivity case long-term gas demand forecasts differ from the base case only in terms of the economic projections used for the forecasts (i.e., higher relative economic growth projections vs. lower relative economic growth projections). The high/low sensitivity cases do not assume different levels of energy efficiency program or other demand reductions.

Figure 2: Forecasted Design Day Demand vs. Available Pipeline Gas Capacity for Aquidneck Island by Long-Term Gas Demand Forecast (Base Case and High/Low Sensitivity Cases)



This projected gas demand growth means that the capacity constraint under the base case demand scenario (i.e., the gap between available pipeline capacity to meet demand on Aquidneck Island and peak design day demand) will grow from the equivalent of 6% of peak demand for winter 2020/21 to 18% of peak demand for winter 2034/35, before accounting for the temporary portable LNG or any other long-term solution.

While addressing the capacity constraint is critical to reliably meeting customers' energy needs, because the capacity constraint manifests on only very cold days when demand is highest, a capacity option that is dispatched (e.g., vaporization of LNG or gas demand response events) would only be called upon infrequently. Today the Company only expects customer demand to exceed the available capacity from AGT to Aquidneck Island on the coldest day planned for (i.e., design day conditions of an average temperature of -3 degrees Fahrenheit over 24 hours). Per the Company's baseline long-term demand forecast, by 2034/35, customer demand will have grown such that on days that are 14 degrees Fahrenheit or colder, demand might exceed the available AGT capacity during at least the peak hour of the day. As such, the capacity constraint conditions will become more frequent but still be limited to very cold days. To illustrate this point, in a "normal year," the Company expects one day that averages 14 degrees Fahrenheit or colder when demand would exceed available capacity from AGT to Aquidneck Island, and in a design year, the Company projects 8 such days.

2.7. National Grid considered a wide range of potential options to provide additional natural gas capacity on Aquidneck Island or reduce gas demand on the island to address the gas capacity constraint and vulnerability needs

As a first step, the Company cast a wide net to consider a spectrum of options that could potentially—independently or in combination—address the capacity constraint and vulnerability needs on Aquidneck Island. The options evaluated are listed in Table 1 below, grouped into four categories.

Table 1: Potential Solutions Considered for Gas Capacity Constraint and Vulnerability Needs

LNG Options	Pipeline Project	Demand-Side Measures	Local Low-Carbon Gas Supply
• Old Mill Lane Portable LNG • Portable LNG at new site on Navy-owned property • Permanent LNG Storage at new site on Navy-owned property • LNG barge	• AGT project	• Gas demand response • Gas energy efficiency • Heat electrification	• Renewable natural gas • Hydrogen

The Company considered but ruled out as a viable option using its former LNG transfer station at the Navy base for reasons that include restrictions on access and lack of site availability in the long-term due to lease expiration. However, the Company has identified alternative properties owned by the Navy that could host an LNG facility, as shown above.

The Company evaluated each of these options across multiple criteria, including its estimated cost, timeline to deployment, magnitude of increased gas capacity or reduced gas demand, reliability, feasibility, community impacts, and environmental impacts.

As a second step, the Company considered how these options might be combined with one another where one option alone could not meet Aquidneck Island's needs or where options could otherwise complement one another.

2.8. Four distinct approaches to solve Aquidneck Island's needs emerged from the variety of options evaluated. There are variations within the approaches depending on specific options selected or combined.

While the Company still hopes to receive stakeholder feedback on all options, four different approaches are emerging to solve the long-term needs of Aquidneck Island, with some variations on each approach. In each approach there is a substantial role for incremental demand-side measures on Aquidneck Island.

- Implement a **non-infrastructure solution** that relies exclusively on heat electrification, gas energy efficiency, and gas demand response to reduce peak gas demand on Aquidneck Island, continuing to rely on portable LNG at Old Mill Lane until both the capacity constraint and vulnerability needs are addressed. Addressing the capacity vulnerability need means reducing overall peak gas demand on Aquidneck Island by more than 40% compared to current projected design day demand so that customer gas demand could be met even in the face of a substantial AGT capacity disruption without LNG on the island.[4] Such an aggressive level of demand reduction will require the majority of residential gas customers on Aquidneck Island to replace their existing gas heating systems with electric heat pumps. Given current up-front and operating cost

[4] This level of demand reduction makes the contingency value of the non-infrastructure solution comparable to the alternative LNG options at least up to a 50% reduction in available capacity on AGT.

differences between these technologies, this will either impose significant costs on the residents of Aquidneck Island, or require large transfers, in the form of customer incentives, from other Rhode Islanders. Incremental demands on the electric system might also eventually require incremental investments in the island's electricity distribution network, too.

- Build a **new LNG solution with the potential for innovative low-carbon gas supply**, phase out the Old Mill Lane Portable LNG operation, and pursue incremental demand-side measures to slow gas demand growth on Aquidneck Island. This approach would continue to rely on some form of LNG on Aquidneck Island, but it could vary in terms of the location and type of LNG facility. Options include a new portable LNG facility on Navy-owned property, a permanent LNG storage facility on Navy-owned property, or an LNG barge offshore of Aquidneck Island. Pairing a new LNG solution with incremental demand-side measures that slow gas demand growth would preserve the contingency capacity over time in the event of a disruption on AGT.[5] By providing a new site for Company operations on Aquidneck Island, the LNG options on Navy-owned property could potentially be a catalyst for an innovative, low-carbon hydrogen production and distribution hub.

- **Pursue an AGT project** to address the capacity constraint and vulnerability needs. At present, there is no formal project proposed by AGT, and the scope of an AGT project could range from a system reinforcement that addresses the capacity vulnerability need on Aquidneck Island to a broader G-system expansion project that would also address regional needs in Rhode Island and Massachusetts. This approach is unique among those presented insofar as it could be a broader gas infrastructure solution that addresses regional needs across multiple gas utility service territories. The variant analyzed herein assumes an AGT project of limited scope focused on resolving the capacity vulnerability for Aquidneck Island paired with incremental demand-side measures to address the capacity constraint need.

- Simply continue using the **Old Mill Lane Portable LNG setup** indefinitely as a long-term solution coupled with incremental demand-side measures to slow gas demand growth on Aquidneck Island to preserve the contingency value from the portable LNG and to limit the circumstances under which the Company would need to dispatch portable LNG. This option addresses the capacity constraint today and through the end of the gas demand forecast period in 2034/35 even before any incremental demand-side measures. It also addresses the capacity vulnerability. Demand-side measures can complement the portable LNG, slowing or offsetting projected gas demand growth and thus preserving the contingency capacity that the LNG provides now in the event of an unexpected pipeline disruption. Pairing Old Mill lane portable LNG with incremental demand-side programs also limits the degree to which the portable LNG would be needed for meeting peak demand on extremely cold days. All other approaches described above will involve some degree of reliance on Old Mill Lane Portable LNG

[5] For this study, the Company analyzed each LNG alternative option paired with incremental gas energy efficiency and gas demand response sufficient to maintain contingency capacity in the face of projected demand growth.

before it can be replaced or phased out because all other options have multi-year lead times.

2.9. National Grid evaluated the potential long-term solutions for Aquidneck Island based on a comprehensive set of criteria

The Company evaluated each of the approaches against a set of criteria as summarized below. Public safety is paramount in everything the Company does, and National Grid must be confident that any option pursued protects the safety of the public and the Company's employees. The Company did not present any options in this study that are not safe for the public and its employees. Key findings from the evaluation include:

- **Timing** – The approaches differ in terms of how long they take to replace the portable LNG at Old Mill Lane, if ever, with a purely non-infrastructure approach taking by far the longest at an estimated 13 more winters of reliance on portable LNG. Alternative LNG options could potentially phase out Old Mill Lane portable LNG after only four more winters.
- **Cost** – The approaches vary substantially in cost. Cost is treated separately below.
- **Reliability** – All of the options can provide the reliability needed for Aquidneck Island. Every option faces potential challenges to reliability that must be managed, such as upstream disruptions on gas pipelines, the operational complexity of LNG options, and the need for effective program design and successful track record of gas demand response.
- **Community Impacts** – The Old Mill Lane portable LNG option rates lowest because of existing concerns from nearby residents. Because none of the other options involve operations within similar proximity to residential neighborhoods, other options may rate more highly on community impacts. However, any of the other infrastructure options could engender similar or even greater community concern from different community members. The non-infrastructure option would require unprecedented levels of effort by community members to participate in adopting energy efficiency measures like home weatherization and replacing gas heating systems with electric heat pumps; moreover, the non-infrastructure option would require continued reliance on Old Mill Lane portable LNG for an estimated 13 more winters, with associated continued community concerns.
- **Local Environmental Impacts –** The continued use of Old Mill Lane portable LNG has no construction required since it is a temporary facility demobilized at the end of each winter. All of the other infrastructure options would have impacts from construction and operation (e.g., noise, air emissions from trucking, water impacts) that would need to be mitigated per applicable rules and regulations. Alternative LNG sites on Navy-owned property are potentially contaminated sites whose environmental remediation requirements are not yet known. Decarbonization, specifically, is considered separately below.
- **Implementation and Feasibility** – The requirements for implementation and the feasibility or likelihood of success differentiate the approaches. Long-term reliance on Old Mill Lane portable LNG faces legal uncertainty that would need to be resolved favorably. Gas pipeline projects have faced opposition that has stymied some projects recently in the Northeast. The non-infrastructure approach relies on rates of gas demand reduction and heat electrification that far exceed anything achieved historically in Rhode Island or elsewhere and assumes demand-side programs that have no current

regulatory approval or funding. The extensive heat electrification required under the non-infrastructure approach may also necessitate incremental electricity distribution network investments.

Table 2: Multi-Criteria Evaluation of Long-Term Solution Approaches

Approach	Size (Dth/day)*	Last Winter Old Mill Lane LNG Needed	Cost	Reliability	Community	Local Environmental Impacts	Implementation / Feasibility
Continue Old Mill Lane Portable LNG							
Old Mill Lane Portable LNG	15,600+ (+3,000 DSM)	n/a	◕	◑	◔	◕	◑
New LNG Solution							
LNG Barge	12,000-14,000	2023/24	◑	◑	◑	◑	◑
Portable LNG at Navy Site	12,000-14,000	2023/24	◔	◑	◑	◑	◕
Portable LNG at Navy Site transition to Permanent LNG Facility**	12,000-14,000	2023/24	◔	◕	◑	◑	◕
Permanent LNG Facility at Navy Site	12,000-14,000	2025/26	◔	◕	◑	◑	◕
AGT Pipeline Project							
AGT Project	N/A (~5,000 DSM)	2028/29	◔	●	◑	◑	◔
Non-Infrastructure							
Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification***	~14,000	2032/2033	◔	◑	◑	●	◔

* Ranges shown for the capacity provided by LNG options reflect potential impact of incremental DSM paired with LNG options. AGT project as presented would include incremental DSM to address capacity constraint need.
**In this option, the Old Mill Lane portable LNG is initially replaced by portable LNG at a new Navy site which is in turn replaced by permanent LNG storage at the new Navy site. This approach replaces Old Mill Lane portable LNG an estimated two years sooner than simply transitioning to a permanent LNG storage solution, but that comes at a higher cost from deploying the interim portable LNG at the new Navy site.
*** Reliability of non-infrastructure options could improve over time as gas demand response programs mature and have more of a track record of reliably delivering during peak demand conditions. The community rating shown for the non-infrastructure approach reflects the demand-side programs themselves; however, this approach would necessitate continued reliance on Old Mill Lane portable LNG for more than another decade, with the accompanying community impacts from that prolonged reliance on that option.

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

2.10. A choice among the long-term solution options must consider what it will take to implement the solution and key implications for customers

In evaluating the different long-term solutions for Aquidneck Island, it is important to look at what it would take to deliver each solution and what the implications would be for customers, as summarized in Table 3.

Table 3: Summary of Implementation Considerations and Implications for Customers of Long-Term Solution Approaches

Approach	Implementation (Policy, Regulatory, Permitting, etc.)	Implications for Customers
	Continue Old Mill Lane Portable LNG	
Old Mill Lane Portable LNG	Resolution of legal uncertainty re: proceeding before Energy Facilities Siting Board (EFSB) over its jurisdiction over temporary portable LNG. Will require town council / local permit approval. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Potential for continued concern from some nearby residents. Indefinite use of portable LNG to meet peak demand.
	New LNG Solution	
LNG Barge	U.S. Coast Guard permitting process required for barge as well as local construction permits. Timely permitting process depends on local stakeholder support. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Old Mill Lane portable LNG likely required for four more winters before this option is ready. Once an LNG barge solution is implemented, there is no need for LNG trucks on Aquidneck Island.
Portable LNG at Navy Site	Successful negotiation of lease with Navy for new site. Environmental site remediation (if applicable). Gas network mains extension to connect to new site. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Old Mill Lane portable LNG likely required for four more winters before this option is ready. Indefinite use of portable LNG to meet peak demand. Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.
Permanent LNG Facility at Navy Site	EFSB approval for permanent facility Successful negotiation of lease with Navy for new site. Environmental site remediation (if applicable). Gas network mains extension to connect to new site.	Old Mill Lane portable LNG likely required for six more winters before this option is ready. LNG trucking would be required for LNG storage refilling. Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.

	Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	
Portable LNG at Navy Site transition to Permanent LNG Facility	Same as two Navy site LNG options above	Old Mill Lane portable LNG likely required for four more winters before this option is ready. LNG trucking would be required for LNG storage refilling. Customers would bear the setup costs of the temporary portable LNG that would only be used before the permanent LNG storage goes into service. Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.
AGT Pipeline Project		
AGT Project	Proposal of specific project by AGT. Potential need for participation agreements with additional Massachusetts gas utilities and formal regulatory approval by Massachusetts Department of Public Utilities for a regional project or a reinforcement project that benefits customers in both Rhode Island and Massachusetts. All necessary federal and state approvals and permits obtained by AGT.	The expected in-service date of an AGT project is unknown and may depend on the scope, but the Company expects an AGT project to be in service no earlier than 2025/26, but the Company projects that it would take an additional three years for incremental demand reductions to scale sufficiently to address the capacity constraint and allow for portable LNG at Old Mill Lane to be phased out.
Non-Infrastructure		
Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification	Regulatory approval for incremental funding and new programs, including approval for heat electrification program(s) with no precedent in Rhode Island. Demand-side management program design and implementation. Workforce development and installer capacity build up specific to Aquidneck Island. Substantial heat electrification on Aquidneck Island could eventually require incremental investments in National Grid's electricity distribution network to accommodate winter load growth. Understanding the needed	Even with aggressive ramp up of demand-side programs, portable LNG likely needed for an estimated 13 more winters before it can be fully replaced by demand-side measures. Customers will have to adopt energy efficiency measures and heat electrification at unprecedented rates. These demand-side measures, even when heavily subsidized, require substantial customer effort and engagement. A non-infrastructure solution would provide qualitatively different resilience in the face of an AGT disruptions (e.g., reductions in gas demand cannot counteract the need for 100% customer

	investment would require further study. Potential for a more codes and standards-based approach to driving electrification, which would require implementation by state and local government.	service interruption if 100% of AGT capacity is lost due to a disruption). In the near term, ambitious ramp up of demand-side programs on Aquidneck island could displace resources devoted to demand-side efforts in other parts of the state which could undermine achievement of statewide gas demand reduction goals. Incremental electricity distribution network investments, if required to accommodate load growth from heat electrification on Aquidneck Island, would increase costs (not yet quantified) for Rhode Island electricity customers.

2.11. Cost-effectiveness and affordability for customers are important considerations and differentiate among the approaches

National Grid modeled the cumulative cost impacts of the different approaches through the time horizon for the study out to 2034/35 (summarized in Figure 3 below). The cost analysis included the forward-looking (i.e., not sunk) costs associated with capital investments, operating expenses, fuel costs, and third-party contracts. It also included the cost of maintaining the Old Mill Lane portable LNG for the interim periods during which it remains needed before the alternatives come online (this is why, for example, the non-infrastructure option includes a cost for infrastructure in Figure 3). Where demand-side measures include savings from avoided energy costs, those are netted out.

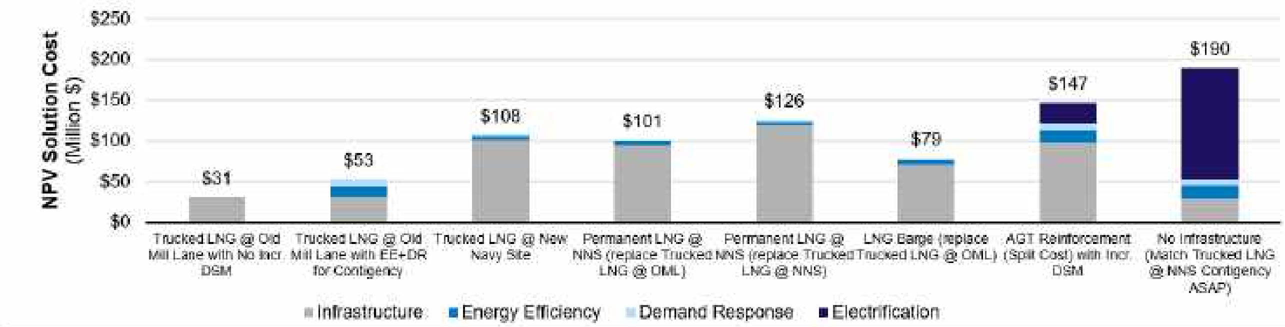
Figure 3 below presents the cumulative net present value (NPV) of estimated costs for the different approaches through the winter of 2034/35. For this cost analysis each of the infrastructure options has been paired with complementary incremental demand-side programs.[6]

All costs are subject to uncertainty, and in some cases rely on conceptual engineering cost estimates for major capital projects. The AGT Project cost is for a project of limited scope focused on system reinforcement; moreover, the cost of a larger AGT Project that would also address regional needs would not be directly comparable to the other options because it would solve other needs in Rhode Island in addition to those on Aquidneck Island. For the non-

[6] Each of the LNG options presented as alternatives to Old Mill Lane portable LNG is paired with incremental gas energy efficiency and gas demand response on Aquidneck Island. The Company set the level of incremental demand-side programs to preserve the contingency capacity offered by the LNG option over time in the face of projected gas demand growth. The level of contingency capacity in each case is benchmarked to what the portable LNG at the new Navy site would provide when it goes into service. Even without being paired with incremental demand-side programs, the portable LNG at Old Mill Lane exceeds this level of contingency capacity. The Company analyzed an option where continued reliance on portable LNG at Old Mill Lane is paired with aggressive incremental gas energy efficiency and demand response on Aquidneck Island which approximately offsets projected gas demand growth and maintains the current level of contingency capacity provided by the Old Mill Lane portable LNG.

infrastructure approach, the Company has assumed a programmatic approach. A more codes and standards-based implementation might have a different cost profile. The non-infrastructure approach does not reflect any incremental costs from electric distribution network investments that the Company expects would eventually be necessary given the level of heat electrification required for that approach.[7]

Figure 3: Net Present Value of Net Utility Implementation Costs for Aquidneck Island Solutions through 2034/35 (Baseline Demand Scenario)[8]



Notes: Net present value of costs up to 2034/35, using a 7.54% discount rate and 2.00% inflation rate. Infrastructure costs include fixed annual costs and net commodity costs, assuming normal year usage. Demand side resource costs include incentive costs and non-incentive program costs, net of gas commodity savings through 2034/35, monetized using the 2018 AESC. Note that any incremental electric infrastructure costs are not included. These are based on demand forecasted in a base economic scenario.

As Figure 3 shows, continued reliance on Old Mill Lane portable LNG (with or without complementary incremental demand-side measures) is estimated to be the least-cost option with the LNG barge option the lowest cost option among the alternatives, followed by the new Navy site LNG options.[9] The AGT project and the non-infrastructure approaches are the most costly. For the purposes of the study's modeling analysis, the AGT project was paired with demand reductions exclusively on Aquidneck Island, but an AGT system reinforcement would allow the capacity constraint need to be met with demand reductions upstream on AGT in certain other parts of Rhode Island, which would create the potential for a lower cost for achieving the needed demand reductions than presented above. The non-infrastructure approaches have lower total costs than shown in Figure 3 when assessed through the Rhode Island benefit-cost framework currently used for energy efficiency.

The methodology used to calculate these net implementation costs aligns with looking at the costs would that flow through to gas customers' bills through 2034/35. The Company also conducted a cost analysis that accounted for impacts on electricity customers, environmental benefits that do not affect customer bills, and benefits that extend beyond 2034/35 from

[7] As both the electric and gas distribution utilities on Aquidneck Island, National Grid did conduct a preliminary, high-level review of the ability of the electric distribution network on Aquidneck Island to support heat electrification and found that individual sections of the electric network would likely experience load growth from heat electrification that would require incremental network investments, but identifying the expected investments and their costs would require further study beyond the scope of this study.

[8] Old Mill Lane. NNS = New Navy Site. Portable (Trucked) LNG at Old Mill Lane is shown with and without incremental demand-side measures, where the latter approach offsets projected demand growth to preserve the benefit of the contingency capacity provided by the portable LNG.

[9] The cost analysis finds the Permanent LNG option to be lower cost than the portable LNG at the new Navy site because the former takes longer to go in-service and thus includes two additional years of reliance on the low-cost portable LNG at Old Mill Lane.

investments made during that period. This broader societal cost analysis substantially changes the relative ranking of the non-infrastructure option. Details on this cost analysis are presented below.

While the net implementation cost analysis above provides a useful “apples-to-apples” comparison across the options in terms of cumulative costs over time, National Grid also estimated the average cost impact on Rhode Island gas customers for the different approaches. Per the standard regulatory cost recovery, the Company assumed that the cost of any solution to the Aquidneck Island needs would be recovered from National Grid gas customers across Rhode Island.[10] While a detailed bill impact analysis is beyond the scope of this study, the table below estimates for each option how the average annual cost per customer compares to the current average total costs paid by all Rhode Island gas customers for their service (gas delivery and the gas commodity)—i.e., about $1,700 per year across residential and business customers.

Table 4: Net Utility Implementation Cost per Customer through 2034/35

<table>
<tr><th colspan="2">Approach</th><th>Average 15-Year Annual Cost per Customer ($ per year)</th><th>Average 15-Year Annual Cost per Customer as % of Average Current Total Cost per Customer</th></tr>
<tr><td colspan="2">Continue Old Mill Lane Portable LNG (without Incremental Demand-Side Measures)</td><td>$10</td><td>0.6%</td></tr>
<tr><td colspan="2">Continue Old Mill Lane (with Incremental Demand-Side Measures)</td><td>$18</td><td>1.0%</td></tr>
<tr><td rowspan="4">New LNG Solution (with Incremental Demand-Side Measures)</td><td>Portable LNG at Navy Site</td><td>$37</td><td>2.2%</td></tr>
<tr><td>Permanent LNG Facility at Navy Site</td><td>$36</td><td>2.1%</td></tr>
<tr><td>Portable LNG at Navy Site transition to Permanent LNG Facility</td><td>$44</td><td>2.6%</td></tr>
<tr><td>LNG Barge</td><td>$27</td><td>1.6%</td></tr>
<tr><td colspan="2">AGT Project (with Incremental Demand-Side Measures)</td><td>$51</td><td>3.0%</td></tr>
<tr><td>Non-Infrastructure</td><td>Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification</td><td>$63</td><td>3.7%</td></tr>
</table>

Notes: The table above ignores nuances in how different cost components for different options might vary in how they are recovered from certain customer types. The analysis excludes capacity-exempt customers.

2.12. The long-term solutions address the Aquidneck Island capacity vulnerability and reduce the potential for future customer service interruptions from an upstream capacity disruption

The portable LNG now in place at Old Mill Lane provides contingency gas capacity. The Company has estimated that even under design day conditions (i.e., with a temperature of -3

[10] However, any incremental investments needed in the Aquidneck Island electric distribution network to support heat electrification, which would be borne by Rhode Island electricity customers and not gas customers. As noted above, such costs are yet to be quantified.

degrees Fahrenheit), with the portable LNG in operation at Old Mill Lane, National Grid could continue to meet nearly all customer demand on Aquidneck Island even if up to half of the AGT gas capacity on which the Company relies was disrupted.

The other LNG approaches would provide similar contingency capacity and resilience to capacity vulnerability as portable LNG at Old Mill Lane and through the same mechanism (i.e., back-up, local gas capacity and supply). However, the Old Mill Lane site is optimally located on National Grid's gas distribution network for this purpose, and the LNG options at the new Navy-owned property would be limited to less capacity.

As the number of customers and customer gas demand on Aquidneck Island grow over time, an LNG solution can support a smaller percentage of total customer demand in the face of a severe capacity disruption on AGT. As such, the Company has presented solutions where the LNG options are paired with incremental demand-side measures on Aquidneck Island that reduce the growth of gas demand. Reducing the growth of gas demand means that over time the LNG options continue to enable the Company to avoid customer service interruptions in the event of an AGT capacity disruption to hold the level of reliability for customers roughly constant.

While the AGT project does not yet have specific details, National Grid expects that it would include reinforcements that would address the root cause of the capacity vulnerability for Aquidneck Island.

For the non-infrastructure approach to address the capacity vulnerability need, demand-side measures would need to not only offset all projected gas demand growth on Aquidneck Island but to reduce total projected peak demand in 2034/35 by half. With this level of peak demand reduction, the Company would have sufficient headroom on AGT at the Portsmouth take station such that the Company could continue to serve customers even in the face of disruptions to AGT gas capacity of near 50% on design day conditions. However, there are limits to the contingency value of such aggressive demand side measures. To illustrate this, with LNG capacity available on Aquidneck Island, the Company could continue to serve a portion of customers even in the face of a complete disruption of gas capacity from AGT. In contrast, a complete loss of AGT capacity to Aquidneck Island would lead to a service interruption for all gas customers on the island in the case of a purely non-infrastructure solution.

2.13. A long-term solution to Aquidneck Island's capacity constraint and vulnerability needs should align with Rhode Island's decarbonization goal

A decision on a long-term solution for Aquidneck Island needs to consider the implications of Rhode Island's long-term decarbonization goal. The Resilient Rhode Island Act (enacted in 2014) established a goal of 80% economy-wide greenhouse gas (GHG) emission reductions relative to a 1990 baseline by 2050 with interim targets of 10% reductions by 2020 and 45% reductions by 2035.

A growing body of evidence—from future energy system studies to technology demonstration projects—shows that gas networks like National Grid's in Rhode Island can play a significant role in decarbonization by transitioning over time to delivering low-/zero-carbon fuels, namely biogas and hydrogen, instead of traditional natural gas.[11] This transition to lower-carbon fuels

[11] See section 11.1 for a sampling of studies.

would complement continued improvements in energy efficiency under Rhode Island's nation-leading programs and some degree of heat electrification to achieve the required overall GHG emission reductions from Rhode Island's heating sector.

In the context of meeting Aquidneck Island's capacity constraint and vulnerability needs, three main findings emerge related to decarbonization:

- **The gas network can be decarbonized** – The gas distribution network can deliver increasingly decarbonized fuels in the future with a transition to biogas and hydrogen in order to meet Rhode Island's decarbonization goals. This means that addressing Aquidneck Island's capacity constraint and vulnerability needs today through LNG or pipeline infrastructure does not "lock in" GHG emissions from traditional natural gas in the future.
- **Demand-side measures can complement gas infrastructure solutions** – Pairing demand-side measures with LNG options or an AGT project to meet today's gas capacity constraint and vulnerability needs can provide GHG emission reductions from energy efficiency and heat electrification, as long as the demand-side programs on Aquidneck Island are incremental to state-wide demand-side programs.
- **A new National Grid facility at a Navy-owned site could grow into an innovative local hydrogen hub** – The LNG options that make use of a new site on Navy-owned property would provide unique opportunities to deploy innovative local low-carbon gas supply technology and potentially lead to the long-term development of a hub for low-carbon gas production, storage, and distribution. Investments to build out the gas network to connect to a new Navy-owned site and to prepare the site for use would not only enable the LNG options there. Those investments would also provide a new location with land that could be used to initially site a hydrogen production facility that could generate and inject low-carbon gas into the Aquidneck Island gas supply. This could grow over time to include hydrogen storage, more hydrogen production capacity, and eventually distribution of hydrogen as a low-carbon fuel. Providing such a suitable site for local low-carbon gas supply is a unique benefit of pursuing a new LNG option at a Navy-owned property.

2.14. National Grid seeks input from Aquidneck Island stakeholders and will recommend a solution after engaging with stakeholders

The Company has released this study so that the general public and interested stakeholders can understand the needs on Aquidneck Island and provide input on their preferred long-term solutions in light of a robust evaluation of different options.

After a period of stakeholder engagement during which the Company looks forward to receiving input and answering questions, the Company will make a recommendation on how it intends to proceed with a long-term solution for Aquidneck Island.

The next steps and timing in terms of regulatory filings or approvals to implement a long-term solution will depend on the solution pursued and in some cases the pathway to implementation may be uncertain at present. Moreover, there may be value for customers in terms of deliberately preserving optionality and not "over deciding" now but rather narrowing the set of potential long-term solutions initially, refining cost estimates and implementation requirements, and possibly even advancing some options—to at least limited degrees—in parallel.

3. Background – An Overview of the Natural Gas System, National Grid's Role, and the Aquidneck Island Service Territory

3.1. Overview of the Natural Gas Industry Structure

In the United States natural gas supply chain, there are three major roles:

- **Production**, which is the upstream extraction of natural gas from the ground and any necessary processing to make it a usable fuel, including liquefaction to create LNG
- **Transmission**, which involves moving the gas from the point of production to where it can be distributed out to customers. This often occurs through pipelines, though it could also occur through trucking or shipping of compressed or liquefied natural gas from the point of production.
- **Distribution**, which involves moving the natural gas from transmission connection points out to commercial, industrial, and residential end users. This is done through a network of gas mains. Before LNG can be distributed to customers for their use through the gas network, it needs to be re-gasified/vaporized. As explain more below, this segment of the natural gas supply chain is where National Grid operates as a gas distribution utility in Rhode Island.

The figure below provides an overview of how this supply chain operates.

Figure 4: United States Natural Gas Supply Chain

3.2. National Grid's Role and Its Rhode Island Service Territory

As the only natural gas local distribution company (LDC) in Rhode Island, National Grid provides natural gas sales and transportation service to approximately 270,000 residential and commercial customers in 33 cities and towns in Rhode Island. The current breakdown of Rhode Island gas customers is summarized in Table 5.

Table 5: National Grid Rhode Island Gas Customer Meter Count[12]

Customer Type	Meter Count
Residential Non-Heating	16,272
Residential Heating	227,624
Commercial and Industrial	24,207
Other	845

National Grid provides natural gas distribution and is served by transmission pipelines. As Rhode Island's gas LDC, National Grid owns, operates, and maintains the gas distribution network that delivers natural gas to its customers, with the responsibility to ensure safe, reliable, affordable, and environmentally sustainable service. National Grid's terms of service and its prices are regulated by the state of Rhode Island. Through its regulated prices, National Grid charges its customers for the costs of delivering natural gas to them. National Grid earns a regulated rate of return (i.e., a regulated profit margin) on the capital it invests in the gas distribution network. The commodity cost of delivered natural gas and gas pipeline transmission charges are a "pass-through" item for the Company to its customers.

3.3. Aquidneck Island Service Territory

Aquidneck Island is the largest island in Narragansett Bay and home to 60,000 residents (about 6% of Rhode Island's total population) across three towns: Portsmouth, Newport, and Middletown. The island's main industries are tourism and hospitality, with limited industrial activity. The Navy operates a base at Naval Station Newport. The Navy is also National Grid's largest gas customer on the island.

National Grid is responsible for distributing natural gas to residents and businesses on Aquidneck Island. The Company serves about 12,500 residential customers and 1,800 business customers.

3.4. Our Service Obligations

In general, gas utilities have an affirmative duty to provide service to qualifying applicants in their service territories. In Rhode Island, the Company is required to furnish gas service to applicants under its filed rates.[13] For both residential and non-residential applicants, National Grid is required to connect and service all customers that request gas service in Rhode Island, unless precluded by certain conditions, such as the incomplete construction of necessary facilities, insufficient supply, or considerations for public safety.

[12] Commercial and industrial meter count includes sales and FT1 and FT2 meter counts. Per Exhibit 5 to National Grid's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 (filed 6/30/20), available in Docket No. 5043 before the Rhode Island Public Utilities Commission at http://www.ripuc.ri.gov/eventsactions/docket/5043page.html

[13] This obligation is set forth in Rhode Island General Laws §§ 39-2-1 and 39-3-10, and further defined in the Rhode Island Division of Public Utilities and Carriers Standards for Gas Utilities, Master Meter Systems and Jurisdictional Propane Systems, 815-RICR-20-00-1, and the Terms and Conditions of the Company's gas tariff, R.I.P.U.C NG-Gas No. 101, Section 1.

4. Study Methodology

4.1. Gas Planning Standards to Ensure Reliability for Customers

When looking at natural gas demand, supply capacity, and different alternatives, it is important to compare them on an "apples to apples" basis. This study expresses natural gas demand and capacity in terms of units of energy, measured in dekatherms (Dth), that are available during the coldest periods for which the Company plans, when it expects customers' gas demand to be highest, measured in Dth/day or Dth/hour.

The Company plans its gas supply resource portfolio and its gas distribution network to standards that define: the coldest year for which the Company plans, known as the "design year;" the coldest day for which the Company plans, known as the "design day;" and the hour of the design day with the highest demand, known as the "design hour."[14] Natural gas utilities define these design standards in terms of heating degree days (HDD).[15] The Company defines its design day standard at 68 HDD, which has a probability of occurrence of once in approximately 59 years. The Company defined this design day standard transparently before the Rhode Island Public Utilities Commission and conducted a cost-benefit analysis to evaluate the cost of maintaining the natural gas supply and capacity resources necessary to meet design day demand requirements versus the cost to customers of experiencing service interruptions.[16]

Within the design day, the Company must ensure that there is enough capacity during peak hours–when maximum demand for natural gas occurs, as customers are heating their homes and businesses, cooking, and using gas for hot water heating. If customers used the same volume of gas each hour, it would be sufficient to look at the daily demand and divide by 24 to ensure the system could provide that amount of gas each hour. The reality is that customers tend to use more gas in the early morning hours, typically 6 – 10 a.m., and again in the evening from 4 – 8 p.m. To ensure that the Company can provide the gas needed by customers during those time periods, the Company looks at its gas capacity needs during the design hour (i.e., the hour on the design day with the highest demand). Based on the intraday variation in customer's demand for natural gas demand, the Company uses a design hour planning standard equal to 5% (i.e. 1/20th) of the design day natural gas demand.

[14] The Company also evaluates its supply/capacity portfolio under a cold snap weather scenario. For the cold snap weather scenario, the Company uses a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year by evaluating weather data over a long-term horizon (for the Company's Long-Range Resource and Requirements Plan submitted in June 2020, this period was 1977/78 to 2016/17). The Company uses the results of the cold snap scenario to test the adequacy of natural gas storage inventories and refill requirements.

[15] A heating degree day compares the mean outdoor temperature recorded for a location over a 24-hour period to a standard temperature, 65° Fahrenheit in the United States. The lower the outside temperature, the higher the number of heating degree days. For example, a day with a mean temperature of 40°F has 25 HDD. Two such cold days in a row have a total of 50 HDD for the two-day period. See "Units and Calculators Explained: Degree Days," U.S. Energy Information Administration, available at https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php.

[16] For more details on how the Company developed its design standards, see Section III.E in National Grid's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 (filed 6/30/20), available in Docket No. 5043 before the Rhode Island Public Utilities Commission at http://www.ripuc.ri.gov/eventsactions/docket/5043page.html.

4.2. Identifying Needs to be Met and Looking at Potential Solutions

The sections below explain in detail the following approach taken by the Company:

- Project long-term future natural gas demand for Rhode Island and use that to create a forecast specific for Aquidneck Island
- Identify natural gas capacity-related needs for Aquidneck Island and show how they change over time with the long-term gas demand forecast
- Investigate and detail a broad array of potential options that could play a role in addressing needs on Aquidneck Island
- Consider how those individual options could be combined to provide complete solutions to the needs on Aquidneck Island and identify the different fundamental approaches from among which to choose
- Evaluate the options across multiple criteria, including cost, reliability, feasibility, etc.

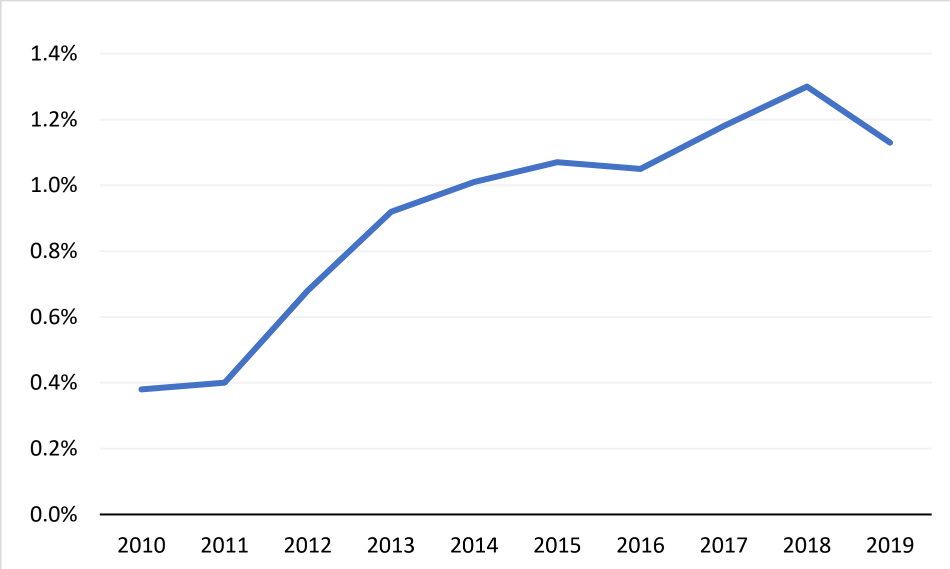
5. Projected Natural Gas Demand through 2034/35 on Aquidneck Island

5.1. Background: Energy Efficiency and New Customer Growth

Over the past ten years in Rhode Island, National Grid has seen a compound average annual growth rate of 1.1% in its number of natural gas customers. The growth in customers is driven by new construction and households and businesses converting from other fuels (e.g., fuel oil and propane) to natural gas.

Rhode Island is a national leader in energy efficiency, ranked third in the nation in the most recent *2019 State Energy Efficiency Scorecard* report from the American Council for an Energy-Efficient Economy. National Grid has implemented comprehensive natural gas energy efficiency programs in Rhode Island. Energy efficiency offerings provide solutions for commercial and industrial, residential, and income eligible customers to reduce their energy consumption by providing incentives for customers to install higher efficiency equipment, to weatherize their buildings, and to motivate behavioral changes. The programs have generated significant and growing natural gas savings (i.e., reduced demand) across the state over the past decade.

Figure 5: Rhode Island Natural Gas Energy Efficiency Savings, as % of Forecasted Sales (Dth)



5.2. 2020/21-2034/35 Gas Demand Forecast at System Level for Rhode Island

National Grid employs a comprehensive methodology for forecasting customer gas demand using a series of econometric models to determine the annual growth expected for Residential Heating, Residential Non-Heating, Commercial, and Industrial markets. To determine the projected growth over the forecast period, the econometric models use economic, demographic, and energy price historical and forecasted data along with weather data to forecast total energy demand before any incremental demand reduction policies and programs beyond what have been in place in the past. The Company then analyzes incremental gas load reductions it expects to achieve through the implementation of its future energy-efficiency programs. The Company's gas demand forecast is based on the April 2020 economic forecast from Moody's Analytics, Inc. that includes the projected impacts that the COVID-19 pandemic will have on the Rhode Island economy. The Company's gas demand forecasting methodology is described in detail in Section III of its Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25.[17]

The company projects 0.8% design day demand CAGR from 2020-2035 in the base demand scenario. This compares to historical CAGR of 1.5% for design day demand from winter 2009/2010 to 2019/2020 in Rhode Island.

5.3. 2020/21-2034/35 Gas Demand Forecast Downscale to Aquidneck Island

For the purposes of addressing the gas capacity needs on Aquidneck Island specifically, the Company needed to downscale the Rhode Island system-level long-term gas demand forecast described above to develop a forecast specific to Aquidneck Island.[18] To do this, the Company

[17] Docket No. 5043 - The Narragansett Electric Co. d/b/a National Grid's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 (filed 6/30/20), available at http://www.ripuc.ri.gov/eventsactions/docket/5043page.html.

[18] As explained in Section III.G in National Grid's long-range plan, the Company develops a spatial gas demand forecast at the zip code level. The zip code-level forecast enables the Company to build gas network reinforcements to address gas demand growth where it is happening. For example, in the case of

decomposed its daily gas sendout on Aquidneck Island by sales category and then forecasted gas demand in the future on Aquidneck Island based on the projected annual growth rates of sendout for each sales category from the Rhode Island system-level forecast described above.

The Company also developed forecasts for Rhode Island that looked at high and low economic outlooks; in these forecasts, the Company uses the projections of economic and demographic data under high and low economic outlooks from Moody's Analytics, Inc. As described above, the Company similarly downscaled these high and low scenarios to Aquidneck Island. Table 6 shows the projected level of growth in peak day gas demand for Aquidneck Island.

Table 6: Aquidneck Island-Specific Long-Term Forecast of Design Day Gas Demand (Dth)

Demand Scenario	2019/20	2024/25	2029/30	2034/35	15-Year CAGR
High	23,794	26,297	26,872	27,898	1.1%
Base	23,794	25,330	25,979	26,936	0.8%
Low	23,794	23,816	25,396	26,395	0.7%

6. National Grid's Natural Gas Supply Capacity in Rhode Island and Aquidneck Island

6.1. Rhode Island Gas Supply Capacity

The Company maintains a natural gas resource portfolio that includes pipeline transportation, underground storage, and peaking resources (e.g., LNG) to meet customer requirements on the forecasted design hour, design day, design year, and normal year including a mid-winter cold snap. Pipeline transportation is available year-round. Underground storage is generally depleted in the heating season and refilled in the non-heating season. Peaking resources such as LNG are often only available for a very limited number of days during the heating season and are used during the coldest days of the year.

The Company has multiple interconnections, also known as city gates or take stations, with the Tennessee Gas Pipeline (TGP) and AGT that provide deliveries from various upstream supply sources and storage facilities. On a design day, the Company expects that approximately 70% of customer requirements will be met with supplies delivered via these interstate pipelines, while the remaining 30% will be met with supplies vaporized from the Company's LNG supply resources.

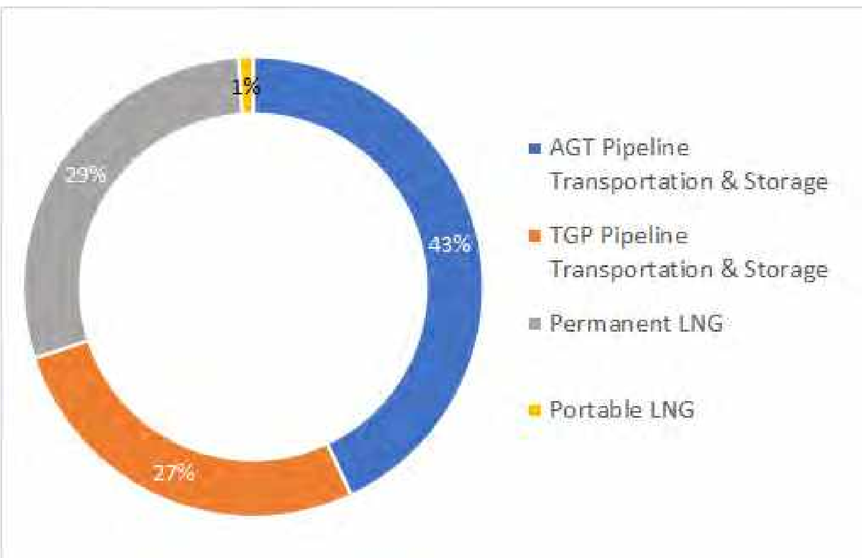
AGT is a Northeastern interstate natural gas pipeline that extends from New Jersey up into Massachusetts. The AGT G-system is a lateral that branches off of the AGT mainline in southern Massachusetts and extends south and east to serve parts of Rhode Island and

Aquidneck Island, the zip code-level forecast helps the Company to determine what the projected gas demand growth is in the towns of Portsmouth, Middletown and Newport. However, this zip code-level forecast only looks at design hour demand and does not provide the 365-day, daily gas demand forecast required to ensure that solutions can address not just the design hour need but also the design year need. For this reason, the Company downscaled its Rhode Island system-level long-term gas demand forecast to create a forecast specific to Aquidneck Island. See National Grid's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 (filed 6/30/20), available in Docket No. 5043 before the Rhode Island Public Utilities Commission at http://www.ripuc.ri.gov/eventsactions/docket/5043page.html southeastern Massachusetts, including Cape Cod. The AGT G-system includes laterals that further branch off, and National Grid's Portsmouth delivery point on Aquidneck Island is served by the G-4 lateral off of the AGT G-system. The Portsmouth delivery point on Aquidneck Island connects to the AGT system via AGT's single 6-inch main crossing the Sakonnet River.

The Company and its affiliate have two permanent LNG facilities in Rhode Island that include storage located in Exeter and Providence. The storage tanks at these facilities are currently refilled in the summer via trucked LNG, with gas stored for use during the subsequent winter season. The Company also uses portable LNG at locations in Cumberland and Portsmouth during the winter season. These locations do not include a significant amount of onsite storage and rely on deliveries via truck during the winter season if the LNG must be used.

An overview of the Company's design day resource allocation is shown below. This resource allocation applies to the Company's full service and capacity eligible transportation load.

Figure 6: National Grid Rhode Island Design Day Resource Allocation: 2020/2021



6.2. Aquidneck Island

Some of the natural gas supplies needed to meet customers' needs in Rhode Island are delivered from AGT. This gas enters the Company's gas distribution system through several take stations connected to AGT – most of which are on Algonquin's G-system.

While the Company's full supply capacity portfolio for meeting the gas demand for all of its Rhode Island gas service territory incorporates TGP supplies, AGT supplies, and LNG supplies, only a small subset of the Company's total AGT capacity and the temporary LNG vaporization equipment in Portsmouth supply Aquidneck Island.

The Company's transportation contracts with AGT provide for deliveries of up to 22,089 Dth per day and up to 1,045 Dth per hour to Aquidneck Island via the single Portsmouth take station on the island. To the extent that customer requirements exceed these limits, the Company presently relies upon portable LNG supply injected into the distribution system at the Old Mill Lane location. The Old Mill Lane portable LNG is described in more detail below; however, it can provide up to 650 Dth per hour of gas supply capacity based on the capacity of the LNG vaporization equipment that has been deployed there.

7. Identified Needs on Aquidneck Island

7.1. Current Needs

Aquidneck Island residents and businesses need access to safe, reliable, and affordable heating. To meet those needs, two challenges must be addressed regarding the long-term natural gas capacity available to the island:

- **The existing gap between gas demand and available gas pipeline capacity on extremely cold winter days.** Currently, projected peak demand on Aquidneck Island during the coldest conditions for which the Company plans exceeds the gas capacity on which the Company can rely from AGT to serve the island via the Portsmouth take station.
- **The system's downstream positioning makes it especially vulnerable to upstream interruption on AGT.** The Portsmouth take station's downstream location at the "end of a pipe" on a branch of the AGT G-system makes it the low-pressure point on the pipeline system, which, combined with having one point of interconnection with AGT through a 6-inch diameter pipe delivering gas into the Portsmouth take station, makes Aquidneck Island vulnerable to upstream disruptions on AGT. Reductions in available natural gas throughput from AGT into Portsmouth could lead to customer service interruptions.

7.2. Gap Between Demand and Pipeline Capacity

As described above, the Company can only count on having access to a certain maximum capacity of natural gas capacity from AGT at the Portsmouth take station on Aquidneck Island (up to 22,089 Dth/day and up to 1,045 Dth/hour), and this maximum capacity alone cannot currently meet Aquidneck Island's projected design day or design hour demand. The projected natural gas demand growth for Aquidneck Island described above will only exacerbate this gap between the projected peak gas demand on the island and the AGT pipeline capacity on which the Company can rely:

- For winter 2020-2021, the design day gap between projected Aquidneck Island gas demand and the available capacity on the AGT pipeline at the Portsmouth take station is 1,385 Dth/day (6% of the available pipeline capacity at the Portsmouth take station). The Company's long-term gas demand forecast projects that the design day gap will grow to 4,847 Dth/day (22% of current pipeline capacity available at the Portsmouth take station) by winter 2034-2035 (see Figure 7 and Figure 8).
- For winter 2020-2021, the design hour gap is 129 Dth/hour (12% of the available pipeline capacity at the Portsmouth take station). The Company's long-term gas demand forecast projects that the design hour gap will grow to 302 Dth/hour (29% of the available pipeline capacity at the Portsmouth take station) by winter 2034-2035 (see Figure 9 and Figure 10).[19]

[19] The differences in percentages between design day and design hour gaps relative to available AGT capacity are because design hour demand is 5% of design day demand, but the maximum hourly

As explained in the following section, the current gap between available firm pipeline capacity for Aquidneck Island and the peak gas demand on the island is not a result of recent growth in customer demand. Rather, changes in AGT operating practices effectively limited the pipeline capacity that the Company can count on during periods of extreme cold. In essence, a gas capacity/demand gap materialized "overnight" with a change in AGT practice that limited how much capacity the Company can plan to use to meet customer needs when demand is highest. This necessitated the portable LNG operations at the Old Mill Lane facility in Portsmouth, which presently fill the capacity/demand gap.

Figure 7: Forecasted Design Day Demand vs. Available Pipeline Gas Capacity for Aquidneck Island

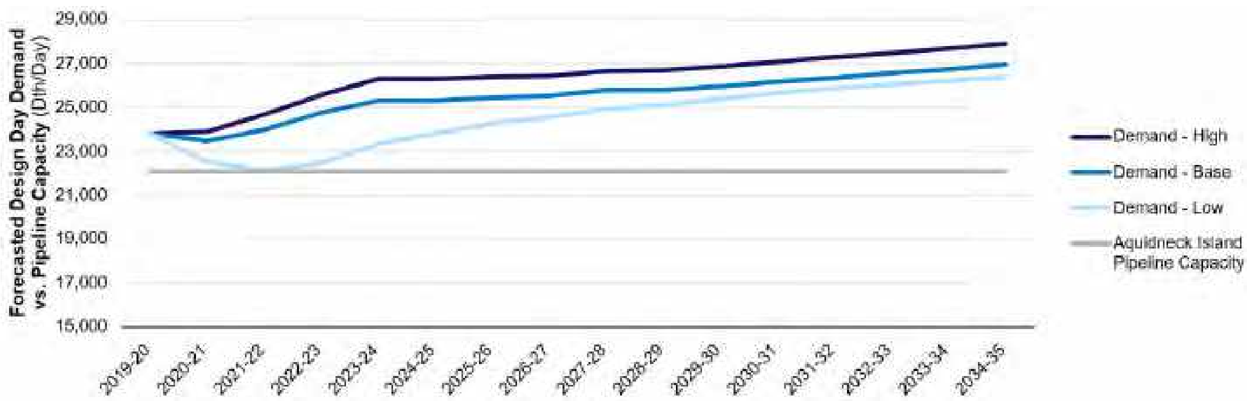
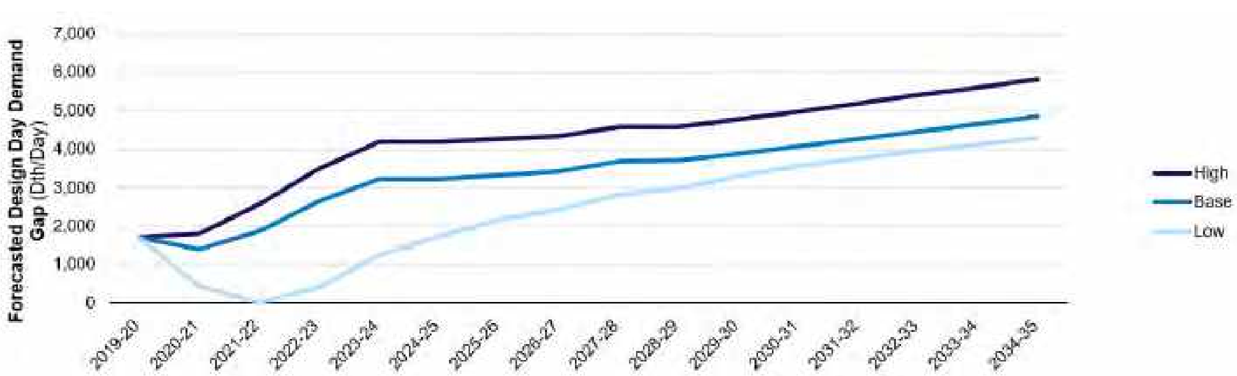


Figure 8: Forecasted Gap Between Design Day Demand and Available Pipeline Gas Capacity for Aquidneck Island



capacity on which the Company can count from AGT at Portsmouth is only 4.7% of the maximum daily capacity.

Figure 9: Forecasted Design Hour Demand vs. Available Pipeline Gas Capacity for Aquidneck Island

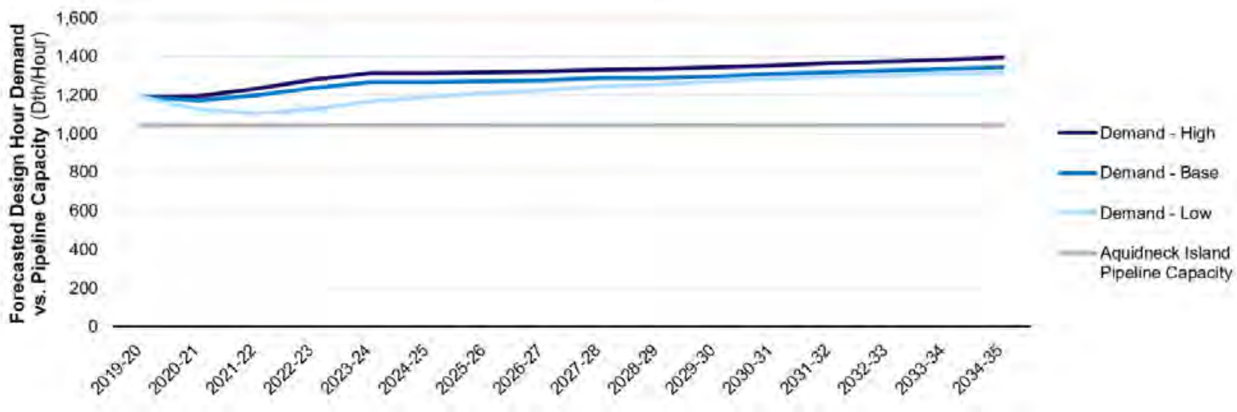
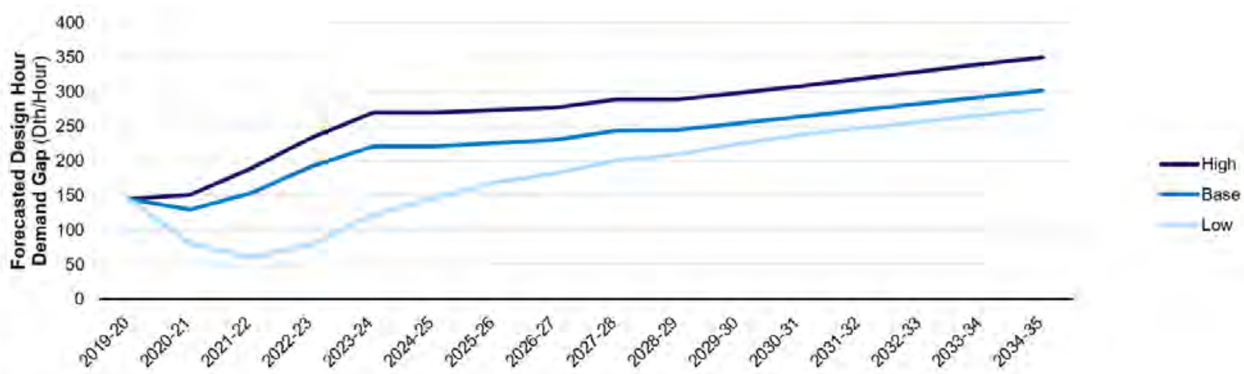


Figure 10: Forecasted Gap Between Design Hour Demand and Available Pipeline Gas Capacity for Aquidneck Island



7.3. Vulnerability of Gas Supply Capacity - Upstream Pipeline Reliability

Although interstate natural gas transportation pipelines traditionally offer strong reliability, Aquidneck Island faces multiple reliability challenges that render its gas supply more potentially vulnerable to disruptions than other areas served by such pipelines.

Historically, the Company has had the operational flexibility with AGT to balance its natural gas deliveries across its multiple take stations on AGT, within the limits of its total contracted capacity on the pipeline. This flexibility allowed the Company to meet the peak demand needs on Aquidneck Island with the AGT capacity available at the Portsmouth take station. However, after AGT experienced a period of high hourly demand on its G system in January 2019, AGT warned that it would restrict or eliminate this flexibility. At that time, AGT notified the Company (and all AGT customers served by AGT's G Lateral) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. For Aquidneck Island, the limits are 22,089 Dth/day and 1,045 Dth/hour, which are less gas capacity than the Company historically has planned to have for Aquidneck Island. AGT's ability to impose the limits is provided for in AGT's tariff approved by the Federal Energy Regulatory Commission (FERC). The Company is not aware of any material improvements to AGT's system that would ameliorate the conditions that prompted the warning in 2019. As such, the Company now makes its planning decisions to prepare for the potential interruption of operational flexibility by AGT, which AGT could impose at any time.[20] This new need to plan for reduced gas capacity available at the Portsmouth take station is what created the present gas capacity constraint need for Aquidneck Island described above.

Even with the Company planning for the lower capacity at the Portsmouth take station of 1,045 Dth per hour, in light of potential restrictions from AGT described above, the Company's ability to meet customer requirements is at risk in the event of an interruption to pipeline gas supply. Although interstate pipelines remain a highly reliable means of transporting natural gas, National Grid has observed issues across the natural gas pipeline industry with compressor failures, ruptures, and unplanned outages. The Company has exposure to such issues across its gas network in the event an interstate pipeline suffers such a disruption, but Aquidneck Island is particularly vulnerable given its location at the "end of a pipe" on the AGT G-system. The Portsmouth take station that serves Aquidneck Island is at the end of the AGT G-4 lateral, which is itself supplied by the G lateral on AGT. This lateral-off-a-lateral configuration downstream of various interconnects and take stations results in greater risk of interruption for customers on Aquidneck Island if there is a pipeline disruption, even if the disruption is well upstream of Portsmouth.

In addition to its vulnerability to upstream disruptions, the Portsmouth take station is connected to the AGT pipeline system via a single 6-inch main crossing the Sakonnet River. This creates the risk of a single point of failure in terms of that main. While this is by no means unique in terms of National Grid's gas network, a long-term solution that would mitigate this single-point-of-failure risk would provide an ancillary benefit in addition to addressing the vulnerability to upstream capacity disruptions.

To address the capacity constraint and vulnerability needs, as described in more detail below, the Company has agreed to temporarily utilize portable LNG operations on Aquidneck Island as

[20] On January 29, 2019, AGT notified the Company (and all AGT customers served by AGT's G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes (i.e., gas withdrawals from the pipeline) to calculated hourly flow limits at each take station. Under the Company's contracts with AGT, those calculated hourly flow limits are either 1/24th or 6% of the Maximum Daily Quantity (MDQ, i.e., the maximum quantity of gas that can be delivered to the Company from the pipeline in a 24-hour period) under each contract. The total calculated hourly flow limits for each take station are then equal to the combined calculated hourly flow limit for all contracts providing deliveries to each take station. For Aquidneck Island, the limits are 22,089 Dth/day and 1,045 Dth/hr. Historically, AGT has not imposed any requirements that its customers manage hourly takes to fall within the calculated hourly flow limits, nor has AGT restricted the Company's ability to balance its overall takes across all take stations. The January 29, 2019, notice expired on April 1, 2019, and, due to the overall mild winter of 2019/20, AGT did not reissue it. However, the Company reasonably expects that AGT may issue a similar notice in the future. AGT may even issue the types of orders described in the January 29, 2019, notice without first issuing another warning should extreme cold temperatures or system issues arise. Accordingly, the Company is making planning decisions so that it is able to comply with any such future orders. Because the Company's peak hour is greater than the daily 1/24th and 6% combination, the Company will now need to ensure that it has sufficient deliverability to meet the peak hour requirements of all of its customers.

a contingency in the event of Company or non-Company upstream issues that affect pipeline deliveries into Portsmouth.

7.4. Customer Service Interruptions as a Result of Supply Capacity Disruptions

In light of the capacity constraint and vulnerability needs described above, the Company has analyzed the number of customers likely to have their natural gas service interrupted in the event of different levels of disruption to the gas throughput on AGT based on the Company's ability to shut-off service to specific large customers or sections of the Aquidneck Island distribution network to reduce demand. This analysis is meant to be indicative of the magnitude of customer service interruptions and not a definitive analysis.[21,22]

The Company analyzed different levels of reductions of AGT pipeline throughput of 25%, 50%, 75%, and 100% of the maximum available capacity of 1,045 Dth/hour.

Table 7 shows how Old Mill Lane portable LNG provides sufficient capacity presently to largely avoid customer service interruptions even in the face of the loss of nearly 50% of the expected gas capacity from AGT at Portsmouth during extremely cold conditions (i.e., design day conditions of 68 HDD, -3 degrees Fahrenheit). Even with loss of 100% of AGT capacity due to a disruption, Old Mill Lane LNG could support the majority of customers on Aquidneck Island. As demand is projected to grow over time, for any given level of AGT capacity disruption, expected customer service interruptions would grow, all else equal.

Table 7: Estimated Customer Service Interruptions in a Contingency Event (AGT Disruption) under Design Day Conditions with Old Mill Lane Portable LNG in Service

% Reduction in Capacity Available from AGT during Design Day (68 HDD) Conditions	Estimated % of Customers with Service Interrupted with Loss of AGT Capacity	
	Old Mill Lane Portable LNG 2020/21	Old Mill Lane Portable LNG 2034/35
0%	0%	0%
25%	0%	0%
50%	1%	16%
75%	24%	36%
100%	44%	57%

7.5. Current Aquidneck Island Winter Reliability Measures

This section outlines the measures currently being taken by the Company on Aquidneck Island in order to meet the capacity constraint and vulnerability needs.

[21] This analysis looks at distributions systems on the island that could be shut down relatively quickly; it did not look at targeted prioritization of large customers for load-shedding in a contingency event.
[22] For the purposes of this study, Company updated an initial customer service interruption analysis done in 2019 for upstream issues that reduce pipeline gas deliveries into Portsmouth as well as for the loss of the Old Mill Lane portable LNG operations. The original analysis evaluated interrupting service to a combination of large-use customers, individual distribution systems, or areas/zones of the low-pressure system in Newport. Regarding the Newport low-pressure system, three zones of approximately 4,000, 1,500, and 1,100 customers were identified based on 16 existing distribution valves that have been confirmed for availability/operability.

Portable LNG equipment has been set up on the Company's Old Mill Lane property in Portsmouth, Rhode Island, to address the projected peak-hour hour usage on Aquidneck Island over and above the AGT capacity on which the Company can plan to have available at the Portsmouth take station. The portable LNG at Old Mill Lane also serves as a contingency in the event of upstream issues affecting pipeline deliveries into Portsmouth. In order to address the capacity vulnerability and to provide contingency capacity in addition to meeting peak demand, the Company plans to have portable LNG operations fully staffed and available for vaporization at 45 HDD (20°F) conditions or colder with a vaporization capacity of 650 Dth per hour. The vaporization capacity of 650 Dth per hour provides approximately 75% of the hourly customer demand on Aquidneck Island at 45 HDD conditions and approximately 50% of the hourly customer demand at 68 HDD (-3°F) conditions, where the latter is the design day planning standard.

National Grid also utilizes three forms of expanded demand-side initiatives in order to slow gas demand growth, reduce demand for gas during peak times and enhance the reliability of gas capacity on Aquidneck Island: (1) a "community initiative" marketing program for energy efficiency offerings; (2) a gas demand response pilot program; and (3) interruptible customer load.

1. The Company has partnered with all three municipalities on Aquidneck Island through the Company's "Community Initiative" marketing program. This program delivers coordinated customer outreach and marketing between Company efforts and municipal partners, with a goal of increasing residential and commercial and industrial (C&I) customer participation in existing gas and electric energy efficiency programs and providing financial incentives to municipalities who achieve stretch goal targets for expanded customer participation. While these measures are not exclusively focused on peak gas demand reductions, customer implementation of weatherization and gas equipment related measures offer the complementary benefit of reducing not only overall gas consumption, but also gas demand during peak times. The Company is exploring measures to re-imagine this program to account for the impact of COVID-19, which has affected local, on-the-ground events for community engagement.

2. The Company currently offers a gas demand response pilot. Under the terms of this pilot, C&I customers can receive financial incentives for curtailing gas usage during peak periods. These reductions are typically delivered through deferring the utilization of gas for use in industrial processes, through adjusting thermostat settings during peak periods, or through temporarily switching to alternative heating sources. Presently, two customers on Aquidneck Island participate in the gas Extended Demand Response pilot, contributing 640 Dth/day of demand reduction by changing to a backup fuel (oil) to reduce demand over the course of the gas day. An additional two customers participate in a Peak-Period Demand Response program, in which the facilities reduce demand during the peak morning hours (6AM-9AM) without the use of backup fuels. Despite the reduction during the Peak Period, these facilities typically do not produce a reduction in terms of total gas day consumption due to pre- and post-event heating.

3. The Naval Station Newport is the only customer on the Aquidneck Island system that can be interrupted during cold weather periods. The base is expected to stop using gas

at temperatures of 25 degrees Fahrenheit or colder (upon notification from National Grid gas control). As a non-firm customer, this Navy account is already excluded from the Company's long-term natural gas demand forecast, and the associated demand is not included in the capacity constraint or capacity vulnerability needs analyses above.

Lastly, the Company also has "contingency plan" procedures in place should customer load shedding prove necessary, with both voluntary load shed and strategic service interruption procedures that the Company could opt to implement to proactively interrupt service to customers based on usage. Both procedures rely on predetermined customer lists established each fall in preparation for the upcoming winter. These more targeted approaches can be used to lessen the chances of enacting broader geographic service interruption approaches.

8. Options to Meet Identified Needs

8.1. Overview and Categories of Options

The Company has looked at an extensive set of options that might be used to address the capacity constraint and/or the capacity vulnerability needs on Aquidneck Island. The Company sought to include a wide range of technically feasible options, even where some options may not have clear implementation pathways or may face substantial hurdles, so as not to prejudge options that might ultimately prove to be appealing on key evaluation criteria or that might garner substantial stakeholder support and thus warrant regulatory or other changes that would enable their implementation.

The options evaluated below fall into several general categories:

- LNG Infrastructure – these options all involve having local LNG capacity in some form on Aquidneck Island (i.e., portable LNG, permanent LNG storage, or an LNG barge)
- AGT Project – this option involves an as-yet unspecified project on AGT that could range in scope from system reinforcement targeted to address the capacity vulnerability need to a broader project to meet regional needs on the AGT G-system from multiple natural gas utilities in Rhode Island and Massachusetts
- Demand-side measures – these options reduce natural gas demand. They include incremental gas energy efficiency (above and beyond planned programs), gas demand response, and heat electrification (both conversion of existing gas customers to electric heat pumps and diversion of new construction and oil/propane heating conversions to electric heat pumps in lieu of becoming new gas heating customers)
- Low-carbon local gas supply – these options provide zero- or low-carbon gas supply on Aquidneck Island from biogas or hydrogen.

As the Company moves to examining specific projects and investments, the level of attractiveness for each individual option has been evaluated considering multiple factors. To make it easier to compare, each of these options is presented in a consistent format, covering the following:

- **Overview** – a description of the infrastructure that would need to get built, or the program that would need to be implemented

- **Size** – Design day capacity (Dth/day), total volume/frequency of use (throughout the year, or just to meet peak demand), and timing of capacity availability (e.g., does it all become immediately available, or is there a build of capacity over time)
- **Cost** – cost to implement the solution, which includes infrastructure and/or program costs and adjustments for commodity costs
- **Safety** – all options evaluated meet safety requirements; additional detail is included to describe the types of safety measures involved.
- **Reliability (certainty of meeting demand)** – likelihood that the option will be able to deliver on its projected capacity, and the risks that it might not deliver
- **Requirements for implementation** – not only technical feasibility, but location siting; hiring for construction/program implementation; requirements to place equipment orders; reliance on customer adoption; etc.
- **Permitting, policy and regulatory requirements** – permits that will need to be approved, policy changes that could enable the option, and regulatory approvals needed or changes that might be required
- **Local environmental impact** – options may have impacts on local air quality, water, noise, etc. Decarbonization implications are considered separately at the end of this study
- **Community impact / attitudes** – impact on business growth and development, and on customer convenience and choice; how components such as location of infrastructure and amount of LNG trucking impact affected communities; community support / opposition
- **Summary table** – following the detailed description of each option, a summary is provided to facilitate comparison of the options

8.2. Temporary Trucked LNG for Temporary Portable LNG Operation on Company-Owned Property at Old Mill Lane

Overview

The Old Mill Lane portable LNG operation was mobilized in anticipation of the 2019/2020 winter season on a 5-acre Company-owned parcel located in Portsmouth, Rhode Island. The portable LNG operation occupies approximately 3,000 square feet of the property. The property is located adjacent to where the distribution system connects to the AGT gas pipeline that supplies Aquidneck Island.[23]

National Grid has contracted with a vendor, Prometheus, with experience with portable LNG for equipment and services at Old Mill Lane. In addition to the trucked LNG, equipment required for portable LNG operation includes portable equipment (i.e., vaporizers, booster pumps, storage tanks, electric generator, and odorizer) deployed to support operations. Additionally, a mobile

[23] The property is also the former propane tank site that provided peaking capability for the Aquidneck Island natural gas distribution system until Providence Gas expanded its pipeline supply capability on the Algonquin pipeline in the late 1980's. The propane tanks were removed from the site in 2014, and the site was vacant until the spring of 2018.

operations trailer is staged for onsite personnel. If National Grid were to continue to operate portable LNG for many years, the Company would consider owning, operating, and maintaining the on-site equipment.

Once the equipment is delivered to the property, a private security guard is always present. Additionally, when the equipment is operational, there is always at least one National Grid employee and a private security officer present on the property. Moreover, one representative of the owner of the vaporization equipment is also scheduled to be onsite whenever equipment is being used.

The Company plans to continue to have Old Mill Lane LNG operations fully staffed and available for vaporization at 45 HDD conditions or colder as a contingency for any upstream issue that adversely impacts pipeline deliveries to the Portsmouth Take Station.

In an “average” year, the Old Mill Lane facility would often never be used (it was not used in 2019-2020), and even in a design year the facility might only be used a few days each winter, with limited (if any) trucking traffic. However, the Company’s contingency planning includes planning for two days of substantial upstream disruption, under which Old Mill Lane’s capacity would be maximized to replace pipeline capacity. This would add up to a total of 48 hours and a total volume of 31,200 Dth, which would require 34 LNG trailer truck deliveries with a total LNG volume of 32,000 Dth. Having sufficient notice to prepare for such a scenario would be important, as it would likely require supplemental technician support, and incremental staging for truck deliveries.

Size

The vaporization capability of 650 Dth/hour currently provides nearly 50% of the required Aquidneck Island volume for a 68 HDD and 75% of the required volume for a 45 HDD. The vaporization capability would provide almost 100% of the required volume on a 30 HDD. A volume of 15,600 Dth (24 x 650 Dth/hour) provides ~ 60% daily volume required for a 68 HDD and ~ 90% daily volume required for a 45 HDD.

Cost

Annual ongoing cost is estimated at ~$3M per year, with a cumulative expenditure of $50M by 2035. There are three components to the cost of constructing, testing and operating each LNG site:

- Capital Investment – Includes engineering and design, development, real estate acquisition, material procurement, site preparation, construction of the LNG assets, testing and commissioning. As the site is already in operations, additional capital costs are negligible.
- Operating and maintenance expenses – Includes contracts with LNG vendors and operation for each cold weather event. Internal labor costs to support operations and maintenance associated with these activities.
- Gas supply costs – Includes the costs of LNG supply and trucking from the point of purchase to the Company’s equipment. Commodity costs assumed to be higher than pipeline.

Safety

Operation of the portable LNG sites for Winter 2020/21 is supported by firms specializing in portable LNG transportation and operations. National Grid will staff each site with qualified personnel to oversee and monitor the operation including flow, temperature and pressure regulation of the gas at the injection point, as well as communicating with Gas Control. Like any satellite operation, difficult operating conditions (weather) for equipment and personnel can introduce the potential for added risk. National Grid has developed comprehensive Emergency Procedures and has coordinated with the local fire department to assist in creating evacuation procedures based on rigorous process safety evaluations and calculations.

Multiple process safety reviews were conducted to identify, quantify and manage risks to employees as well as to members of the public in the nearby areas of each site. This included facility siting assessments to understand and reduce the potential risk associated with the Old Mill Lane location, which is near a public road. It also included process hazard analyses of the injection stations' design to understand and reduce the potential risks that could occur during the unloading and injection process. Additionally, a third-party independent assurance assessment is being performed for each site to review design, construction, LNG filling operations, transportation and LNG site operation and injection into National Grid's systems.

Reliability

Portable LNG has historically been viewed as a contingency operation to augment baseload supply or capacity in the event of an unplanned shortage or in support of planned pipeline maintenance operations requiring interruption of supply to National Grid. As a contingency, this capacity option is reliable, and National Grid has a demonstrated history of successful deployments of portable LNG and CNG operations across its service territory. These operations have been successful in both short-term and longer-term applications ensuring customer reliability during off-peak and peak periods of demand. Portable solutions are most viable to support contingency and peaking options for supply capacity–i.e., to be available to support firm gas demand during the coldest winter periods. Additionally, in certain applications, portable facilities can support emergency operations. However, staffing levels and availability of real estate must be carefully planned to site any long-term portable pipeline operation.

Inherent with this option is the necessity to procure LNG supply upstream of National Grid's system and transport the supply to the portable LNG site. The transportation could be impacted by multiple events (e.g., road/bridge closures due to automobile accidents or construction, high winds, and inclement weather) with the risk of a customer service interruption if supply cannot be delivered on-time to meet the demand. The portable LNG equipment deployed at Old Mill Lane considers those risks, and the operation includes onsite storage to mitigate the transportation risks associated with inclement weather and other transportation impacts allowing greater flexibility of operations. The National Grid operations team works from a multi-day forecast that provides the transportation vendor an ability to preposition vehicles ahead of any impending cold or inclement weather. Additionally, National Grid has previously conducted quantitative risk assessments for similar transportation operations and as a result has incorporated additional procedures and controls including regular audits of LNG transportation with our vendors.

Requirements for Implementation

<u>LNG Operational and Emergency Response Plan</u>

The portable LNG operations at Old Mill Lane will be used to address peak-hour usage on Aquidneck Island above the contract maximum daily hourly quantity (MDHQ) and as a contingency in the event of upstream issues, both Company and non-Company, affecting pipeline deliveries into Portsmouth.

The parameters that determine when the site will be put into operation are as follows (this describes the arrangement with Prometheus under the current contract with the Company, which may change in the future):

- If weather forecasts predict 45 HDD conditions or greater, Prometheus personnel will be on-site at Old Mill Lane to operate the facility.
    - If weather forecasts predict 61 HDD conditions (4 degrees F) or colder, the Company will start vaporizing LNG as needed to ensure that the MDHQ is not exceeded. At 68 HDD (-3 degrees F) design conditions, 4 hours of LNG operations are required for a total of 350 Dth, which one (1) LNG Trailer Truck can provide. The site was setup with a storage capacity of approximately 68,000 gallons of LNG which can supplement a significant portion of the peak day demand.
    - In the event that there is an upstream disruption affecting pipeline gas deliveries, the Company will commence portable LNG operations at Old Mill Lane.
- In addition, if weather forecasts predict less than 45 HDD, Prometheus personnel will not be on site but are available within 1-hour if there is an upstream service disruption.

The LNG Portable Operation at Portsmouth (Old Mill Lane) was setup pursuant to the requirements of 40 CFR 193.2019 and the associated safety provisions described in NFPA 2-3.4 (2001). In regard to emergency response, site specific procedures have been established for emergency site access, fire, major leak or spill, emergency evacuation plan, extinguishers and combustible gas detectors and will be kept on site. In addition, the corporate response to an LNG incident at the Portsmouth (Old Mill Lane) facility is documented in the Rhode Island Gas Emergency Response Plan.

Permitting, Policy and Regulatory Requirements

The portable LNG operation is operating under a two-year RI EFSB waiver, which is effective through the winter 2020-2021 heating season. The Company is drafting a Petition for Declaratory Order to the RI EFSB seeking a ruling that temporary portable LNG operations like Old Mill Lane are not “major energy facilities” and thus do not require EFSB approval. In the absence of EFSB jurisdiction, the Company would need to secure town council / local permit approval to establish the site for longer-term operations.

Environmental Impact

The Project is not expected to have any environmental impacts or social impacts beyond the setup and removal of the Equipment, the traffic increase from people working on the site, and the delivery of LNG to the site. For the same reasons there are no anticipated impacts to the public health, safety, and welfare. In addition, the setup and operation of the Equipment will be completed in a manner that meets or exceeds the federal regulations for Mobile and temporary LNG facilities, 49 C.F.R. § 193.2019. It should be noted that during the winter 2019-2020 mobilization, the Project was not needed to supplement natural gas capacity.

Community Impact / Attitudes

As described above, the Old Mill Lane site is within the vicinity of residential neighborhoods, and has ongoing operations (on-site personnel, limited traffic, facilities work) even when LNG is not being vaporized. Residents have complained about noise from a generator than ran 24/7 on-site and from the regular venting of LNG tanks. Other complaints include aesthetics and lighting. To mitigate these concerns, National Grid is installing an electric service to reduce ongoing noise from on-site electricity generation and constraining any essential venting operations to weekdays. The Company also agreed to install landscaping and fencing to screen the facility from view. Existing on-site lighting has been positioned inward to minimize impact on neighbors.

Portable LNG is only needed on the most extreme cold winter days or in the event of a pipeline capacity disruption. The Old Mill Lane deployment includes onsite storage of liquid volume to manage the volume of trucking and allowing for flexibility of operations for short duration events thereby minimizing LNG trucking operations. If there were a pipeline disruption event that required using the portable LNG to meet customer gas demand, trucking of LNG would be necessary for any prolonged periods of operation.

The site is also demobilized after the end of the winter.

Summary

The table below summarizes the assessment of the option to continue using trucked LNG at the Old Mill Lane site as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 8: Temporary Trucked LNG for Temporary Portable LNG Operation on Company Owned Property at Old Mill Lane Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Continue to operate portable LNG at Old Mill Lane, Portsmouth, to meet peak demand and provide contingency capacity.
Size	Up to 15,600 Dth/day	Hourly capacity is determined by current contracted vaporization capacity, not limits of system takeaway capability. Daily capacity is based on operating the vaporizers at 100% capacity for 24 hours on a design peak day.
Timeframe	---	In operation.
Safety & Reliability		
Safety	---	The Company conducted a series of safety reviews to identify and mitigate risks of a satellite operation, including a third-party independent assessment. National Grid has staffed Old Mill Lane with qualified personnel to ensure safe operations.
Reliability	◑	Reliable source of capacity; however, would be susceptible to weather events (e.g. blizzards) affecting trucked LNG to replenish onsite storage and impact on personnel to operate during these conditions
Project Implementation & Cost		
Cost	◕	Ongoing cost of ~$3M per year.
Requirements for Implementation	◑	Currently in operations.
Permitting, Policy and Regulatory Requirements	◑	Have approval under a RI EFSB two-year waiver to operate temporary portable LNG at Old Mill Lane, Portsmouth, covering the 2019/20 and 2020/21 heating seasons. Current plan is to submit a Declaratory Order to the RI EFSB that temporary portable LNG operations are not within their jurisdiction. If approved, will be able to

		operate portable LNG at this location and other locations in RI.
Environmental & Community Impact		
Environmental Impact	◕	Environmental impacts are not expected.
Community Impact / Attitudes	◔	There is local opposition to operating at current location, which is near a residential neighborhood (only operational in winter months). Regulators have requested the Company evaluate options to relocate operation to an alternate location.

8.3. Trucked LNG for Temporary Portable LNG Operation at a New Navy Site

Overview

The temporary portable LNG operation includes the continued use of portable LNG to serve Aquidneck Island at the current location at Old Mill Lane, Portsmouth, or a potential alternative location on a Navy-owned property. Due to local opposition to operating temporary portable LNG at current location, the Company is exploring alternate locations to operate temporary portable LNG. The best available alternate locations are several parcels available for lease from the Navy. The Company requires to continue temporary portable LNG operation at Old Mill Lane until temporary portable LNG operations are in-service at an alternate location.

The proposed scope of work to relocate the temporary portable LNG operations to one of the available Navy parcels includes:

- Environmental site remediation if needed, civil site preparation for temporary portable LNG use and purchase of equipment for the portable LNG operation.
- Installing almost 5 miles of 16 inch 99 psig steel main to interconnect to existing 99 psig system.[24]
- Installing a new 99 psig to 55 psig district regulator in the vicinity of the parcel.

The Company requires portable LNG operations fully staffed and available for vaporization at 45 HDD conditions or colder as a contingency for any upstream issue that adversely impacts pipeline deliveries to the Portsmouth Take Station. The Company contingency planning includes planning for two such days of continued upstream disruption, under which a Portable LNG site's capacity would be maximized to replace pipeline capacity. This would add up to a total of 48 hours and a volume of 24,000 Dth needed. Based on calculations, this requires 26 LNG trailer truck deliveries with a total LNG volume of 24,700 Dth.

Size

A vaporization capacity of 600 Dth/hour provides a daily volume of 12,000 Dth (20 x 600 Dth/hour).

For LNG options at a potential Navy site or a potential LNG barge, daily capacity will likely face an upper bound due to the resource's 'downstream' positioning on the distribution system (as compared to Old Mill Lane's 'upstream' position at the Portsmouth take station). Daily capacity was sized at 20x design hour capacity (equivalent to the ratio between design day demand and design hour demand).

[24] Psig = Pounds per square in gauge, a measure of pressure.

Cost

Annualized cost was estimated at ~$15M, with a cumulative expenditure of ~$180M (excluding any additional demand side measures) by 2035. There are three components to the cost of constructing, testing and operating each LNG site:

- Capital Investment – Includes engineering and design, development, real estate acquisition, material procurement, site preparation, construction of the LNG assets, testing and commissioning.
- Operating and maintenance expenses – Includes contracts with LNG vendors and operation for each cold weather event. Internal labor costs to support operations and maintenance associated with these activities.
- Gas supply costs – Includes the costs of LNG supply and trucking from the point of purchase to the Company's equipment. Commodity cost assumed higher than pipeline.

Safety

When the alternate site for relocation is selected, the Company will staff each site with qualified personnel to oversee the operation including temperature and pressure regulation of the gas at the injection point, monitor flows and pressures on site and communicate with Gas Control. Like any satellite operation, difficult operating conditions (weather) for equipment and personnel will add to the risk of operations.

Multiple process safety reviews will be conducted to identify, quantify and manage risks to employees as well as to members of the public in the nearby areas of each site. This includes facility siting assessments to understand and reduce the potential risk associated with the particular location. It also includes process hazard analyses of the injection stations' design to understand and reduce the potential risks that could occur during the unloading and injection process. Additionally, a third-party independent assurance assessment will be performed for each site to review design, construction, LNG filling operations, transportation and LNG site operation and injection into National Grid's systems.

Reliability

Notably, this capacity option has historically been viewed as a contingency operation to augment capacity in the event of an unplanned shortage. As a contingency, this capacity option is reliable. However, as an option for natural gas baseload capacity, this option is medium to low in reliability.

Due to the transportation-focused nature of this option, LNG capacity could be impacted by multiple events (e.g., road/bridge closures due to automobile accidents or construction, high winds, and inclement weather). Additionally, future LNG supply issues may arise as demand for LNG supply and transportation increases over time. Scalability of this option also impacts its viability as a long-term solution for Rhode Island.

Requirements for Implementation

<u>LNG Operational and Emergency Response Plan</u>

When the temporary portable LNG operations are relocated, the requirements will be similar to Old Mill Lane, however, the vaporization capability is lower at the available Navy parcels The portable LNG operations at the proposed alternate locations will be used to address peak-hour hour usage on Aquidneck Island above the contract maximum daily hourly quantity (MDHQ) and as a contingency in the event of upstream issues, both Company and non-Company, affecting pipeline deliveries into Portsmouth.

The parameters that determine when the alternate site will be put into operation are as follows:

- If weather forecasts predict 45 HDD conditions or greater, the Company will have personnel will be on-site at alternate site to operate the facility. Weather conditions will need to be determined when the alternate site is in-service.
- The alternate site is proposed to have a storage capacity of approximately 80,000 gallons of LNG which can satisfy a significant portion of the peak day demand.
- In the event that there is an upstream disruption affecting pipeline gas deliveries, the Company will commence portable LNG operations at the alternate site.
- In addition, if weather forecasts predict less than 45 HDD, the Company personnel will not be on site but are available within 1-hour if there is an upstream service disruption.

When the temporary portable LNG operation is relocated to the alternate site, the LNG Portable Operation will be setup pursuant to the requirements of 40 CFR 193.2019 and the associated safety provisions described in NFPA 2-3.4 (2001). In regard to emergency response, site specific procedures will be established for emergency site access, fire, major leak or spill, emergency evacuation plan, extinguishers and combustible gas detectors and will be kept on site. In addition, the corporate response to an LNG incident at the alternate location will be documented in the Rhode Island Gas Emergency Response Plan.

The Company is drafting a Petition for Declaratory Order to the RI EFSB with the position that temporary portable LNG operations are not a "major energy facility" and are not subject to the jurisdiction of the EFSB. If the RI EFSB agrees that temporary portable LNG operations are not a "major energy facility", relocation to an alternate site will not require RI EFSB approval.

Environmental Impact

Similar to temporary portable LNG operations at Old Mill Lane, relocating to an alternate location is not expected to have any environmental impacts or social impacts beyond the setup and removal of the Equipment, the traffic increase from people working on the site, and the delivery of LNG to the site. For the same reasons there are no anticipated impacts to the public health, safety, and welfare. In addition, the setup and operation of the Equipment will be completed in a manner that meets or exceeds the federal regulations for Mobile and temporary LNG facilities, 49 C.F.R. § 193.2019. It should be noted that during the winter 2019-2020 mobilization, the Project was not needed to supplement natural gas capacity.

Community Impact / Attitudes

As described above, cold weather events necessitating capacity to ensure system reliability will require a volume of LNG tractor trailer trucks traveling on the interstate highways, over bridges, and on local roads to access each site to support site operations. The existing site is within the vicinity of located in residential neighborhoods. The Company will make efforts to minimize the impact of operations to abutters and residential neighborhoods.

Summary

The table below summarizes the assessment of the option to use trucked LNG at a Navy-owned property as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 9: Summary of Trucked LNG at Navy-Owned Property Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description

Overview	---	Due to local opposition, relocate portable LNG operation to a Navy-owned parcel. Relocation could require environmental site remediation and preparation for portable LNG operation 2-4 miles of 16in steel distribution main extension and new district regulator. Portable LNG operation at Old Mill Ln will be required until new portable LNG location is in service.
Size	12,000 Dth/day	Hourly capacity is based on June 2019 forecast with complete system interconnect to 99 psig system and 55 psig system. The system takeaway capability is dependent on the demand forecast.
Timeframe	---	Approximately 4 years to implement
Safety & Reliability		
Safety	---	Site analysis will involve stringent evaluation of safety measures
Reliability	◑	Reliable source of capacity; however, would be susceptible to weather events (e.g. blizzards) affecting trucked LNG to replenish onsite storage and impact on personnel to operate during these conditions
Project Implementation & Cost		
Cost	◔	Estimated cost for relocation is $15M per year.
Requirements for Implementation	◕	To operate on Navy parcels, will require a lease to use land, an easement to install main in their streets and security clearance for all Company and contractor personnel.
Permitting, Policy and Regulatory Requirements	◑	Current strategy is to submit a Declaratory Order to the RI EFSB that temporary portable LNG operations are not within their jurisdiction. If approved, will be able to operate portable LNG at this location and other locations in RI. Will need to operate portable LNG at current location until a new location is in service. Will require a lease and easement from the Navy. All employees and contractors requiring access to facility will require Navy vetting/background check to gain security clearance. Security clearance is good for six months and will require Navy vetting/background check for renewal. Could require a permit or easement for main extension because of a site's proximity to state owned railroad. Will require municipal permit for main extension within municipal ROW.
Environmental & Community Impact		
Environmental Impact	◑	Mitigation measures will be put in place to address environmental impact.
Community Impact / Attitudes	◑	Aware of local opposition to some aspects of solar farm development on a Navy parcel within vicinity.

8.4. Permanent LNG at a New Navy Site

Overview

Adding fixed LNG peaking capacity involves construction of a new LNG peak shaving plant and related infrastructure (e.g., tanks, structure, vaporization, etc.). The Company could additionally investigate liquefaction capabilities. The peak-shaving plant would allow for storing LNG and vaporizing and injecting that supply for use during peak times (e.g., during colder temperatures when the base load capacity cannot meet the required demand). Currently, there are two LNG facilities in the Rhode Island National Grid territory—the NG Providence LNG Plant, which is adding liquefaction equipment, and the Exeter LNG Plant—and this proposal is for a third (though smaller) facility. It is important to note that this project would require approval from the RI EFSB.

Size

The plans for this option would potentially supply up to 12,000 Dth / day of capacity with 600 Dth capacity in the design hour.

For LNG options at a potential Navy site or a potential LNG barge, daily capacity will likely face an upper bound due to the resource's 'downstream' positioning on the distribution system (as compared to Old Mill Lane's 'upstream' position at the Portsmouth take station). Daily capacity was sized at 20x design hour capacity (equivalent to the ratio between design day demand and design hour demand).

Cost

Annual cost is estimated at ~$18M per year, with a cumulative cost (excluding additional demand side measures) of ~$180M-$215M depending on whether the site replaces Old Mill Lane or portable Navy site operations. While a location for a permanent site hasn't been finalized (additional feasibility studies would need to be performed to revise high-level estimates), there are three components to the cost of constructing, testing and operating an LNG location:

- Capital Investment – Includes engineering and design, development, real estate acquisition, material procurement, site preparation, construction of the LNG assets, testing and commissioning.
- Operating and maintenance expenses – Includes contracts with LNG vendors and operation for each cold weather event. Internal labor costs to support operations and maintenance associated with these activities.
- Gas supply costs – Commodity cost would likely be lower than portable LNG operations.

Safety

Construction and use of this new facility will require significant stakeholder involvement, specifically with local zoning boards as well as local fire departments similar to what is done for our existing LNG facilities. Each LNG facility constructed after March 31, 2000 must comply with requirements of 49 CFR 193 subpart D and NFPA 59A, which states: a plant and site evaluation shall identify and analyze potential incidents that have a bearing on the safety of plant personnel and the surrounding public. The plant and site evaluation shall also identify safety and security measures incorporated in the design and operation of the plant considering the following: 1) Process hazard analysis, 2) Transportation activities that might impact the proposed plant, 3) Adjacent facility hazards, 4) Meteorological and geological conditions, and 5) Security threat and vulnerability analysis.

Reliability

LNG facilities are extremely reliable and in service across the country. National Grid has significant operations and maintenance experience with 12 facilities in service across the Massachusetts, Rhode Island, and Downstate NY areas.

Requirements for Implementation

Operating on Navy parcels will require a lease to use land, an easement to install main, and security clearance for all Company and contractor personnel. When an in-service date is identified, additional requirements for implementation will be evaluated.

Permitting, Policy, and Regulatory Requirements

This option will require RI EFSB approval.

Environmental Impact

Local environmental impacts, beyond initial construction of the site, are not expected.

Community Impact / Attitudes

For this option, the Company will endeavor to fill onsite storage prior to when vaporization is need for cold weather events. If the inventory is depleted, refill during the winter may be necessary. As described above, cold weather events necessitating capacity to ensure system reliability will require a volume of LNG tractor trailer trucks traveling on the interstate highways, over bridges, and on local roads to access each site to support site operations. The Company will make efforts to minimize the impact of operations to abutters and residential neighborhoods.

Summary

The table below summarizes the assessment of the option to use a Permanent LNG site on Navy-owned property as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 10: Summary of Permanent LNG at Navy-Owned Property Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Construct and operate a permanent LNG facility on a Navy-owned parcel. Construction will require new LNG facility construction, 2-4 miles of 16in steel distribution main extension and new district regulator; could require environmental remediation. Will require to operate portable LNG, at Old Mill Lane or new location, until permanent LNG facility is in service.
Size	12,000 Dth/Day	System capacity estimated; full daily capacity unknown until site surveying / engineering can determine capabilities.
Timeframe	---	Approximately 6 years to implement.
Safety & Reliability		
Safety	---	Plant and site analysis will involve stringent evaluation of safety measures.

Reliability	◕	Permanent LNG facilities have historically been very reliable – National Grid has extensive experience in this area.
Project Implementation & Cost		
Cost	◔	Annual cost estimated around $18M per year—conceptual estimate will need to be validated with further assessment / site finalization.
Requirements for Implementation	◕	To operate on Navy parcels, will require a lease to use land, an easement to install main in their streets and security clearance for all Company and contractor personnel.
Permitting, Policy and Regulatory Requirements	◕	RI EFSB approval required for new permanent LNG facility. Will need to operate portable LNG at current location until a new location is in service. Will require a lease and easement from the Navy. All employees and contractors requiring access to facility will require Navy vetting/background check to gain security clearance. Security clearance is good for six months and will require Navy vetting/background check for renewal. Could require a permit or easement for main extension because of a site's close proximity to state owned railroad. Will require municipal permit for main extension within municipal ROW.
Environmental & Community Impact		
Environmental Impact	◑	Local environmental impacts are not expected.
Community Impact / Attitudes	◑	Assessment based on opposition to temporary portable LNG operation, though this site would be further removed from residential areas and permanent.

8.5. LNG Barge

Overview

The LNG Barge option would include contracting with a third-party owner for one (or more) specialty LNG Barge(s). These barges can be sized and designed for function to serve Rhode Island's peak capacity needs as well as other markets for the barge owner. Vaporization, metering, and odorant equipment will be integrated into the design providing a small-scale LNG peak shaver. In this configuration, these are referred to as Floating Storage and Regassification Barges (FSRB). FSRBs are further categorized as either (1) tow barges where a tugboat tows the vessel or (2) an Articulated Tug/Barge Unit (ATB) where the tugboat connects with pinions to a notch in the FSRB stern. For Aquidneck Island service, a shallow water offshore location within 3 miles of the coast would benefit the region with minimal on-land construction needed and appropriate clearance from shipping lanes, marine commerce, and the coast. Utilizing an FSRB is a new concept for the U.S. market; however, one such barge was delivered in 2018 and is currently transporting LNG from the U.S. gulf to Puerto Rico to "bunker" or fuel ships.

Two other barges are in construction in U.S. shipyards. Rhode Island could model the solution based on these projects.

This is an emerging market in the US driven by UN Climate Policy, through the International Maritime Organization (IMO) to reduce CO_2 emissions in the marine transportation sector. LNG bunkering barges are being built to refuel ships that have historically powered by oil. Prior to this change, the limiting factor to this market has been the US Jones Act Law (1920) that requires coastwise trade to be on ships or vessels built in the U.S., owned by U.S. companies (i.e. US Flagged) and operated by U.S. crew. Since all worldwide LNG trade is on non-Jones Act ships, LNG cannot be legally moved from one U.S. port to another without an emergency waiver as is used during national emergencies. To date, the market for U.S. owned/operated barges is small, but this is changing as the U.S. industry continues to grow. For Rhode Island, a compliant Jones Act barge is needed. There are three potential types of U.S. sources of LNG under consideration: 1) US or Canadian east coast terminals such as Cove Point, MD and Elba Island, GA, 2) from a passing LNG tanker at sea, or 3) by LNG truck to be loaded at a remote site.

Size

National Grid can request a purpose-built barge for this market. A barge size we are considering is one of the models being used today in the US holding approximately 50,000 Dth, the equivalent of 50 LNG trucks, and could be outfitted to deliver the required peak service listed in this study for a period of up to 10 days before replenishment is required. The physical size of this barge example is roughly 200 feet long and less than 50 feet wide (beam).

For LNG options at a potential Navy site or a potential LNG barge, daily capacity will likely face an upper bound due to the resource's 'downstream' positioning on the distribution system (as compared to Old Mill Lane's 'upstream' position at the Portsmouth take station). Daily capacity was sized at 20x design hour capacity (equivalent to the ratio between design day demand and design hour demand).

Cost

To prepare the gas system for the offshore barge connection, a tee on the existing system and pipe leading out to the buoy is needed. The cost for construction and materials for this pipe and buoy is expected to be a rate-based asset similar to any other gas main. The anticipated commercial model for the barge, operations, and LNG capacity would be a service rate model where the supplier is paid a reservation charge for the annual service covering the provider's costs. We expect the LNG used would be offered at a market price to be negotiated. Given the nature of this type of operation, the reservation charge is anticipated to be higher than that of traditional pipeline supply but given the small annual volumes needed, the total annual cost of this option including the permanent rate based pipe is expected to be approximately $10M, with a cumulative cost (excluding additional demand-side measures, and including cost of interim solutions) of ~$125M by 2035. National Grid would run a competitive solicitation to select a provider based on price and qualifications.

Safety

US Coast Guard (USCG) and US Maritime Administration (MARAD) will conduct a security / safety review as part of the federal permitting process. A process safety approach is used to identify, quantify and manage risks by these agencies. Once in operation, the FSRB will be subject to a specifically designed USCG Security Zone per 33 CFR Part 165 Subpart D. Furthermore, the USCG manages a rigorous barge inspection and regulation program codified by US safety codes under 33 CFR Section 83. This includes mandates to inspect barges on an annual basis for material condition, safety functions, operations, security programs, and crew training.

During the siting review, the barge developer will be required to provide a process safety and general safety assessment that must be approved by the USCG LNG Center of Excellence as part of the Waterways Suitability Analysis (WSA) process. The assessment must consider all the leak scenarios identified in the extensive research performed by Sandia National Laboratories in 2004 and 2008. As a result of the increased interest in LNG import facilities in the US during the early 2000’s, the US DOE sanctioned the work at Sandia Labs. Examples of these scenarios include large breaches due to terrorism, ramming, and the largest physically possible leaks based on the design of the barge. Only when these worst-case scenarios are satisfied and proven safe for the public, can the permitting proceed. It should be noted that the scenarios were developed for large LNG tankers but will be conservatively applied to the smaller LNG barge in the same manner.

Reliability

The interconnection to the Aquidneck Island gas system has been selected to most effectively provide pressure and supply support near the end of the gas system. On board the barge, the integrated systems are very similar to those used by LNG Operations at National Grid’s own LNG plants. From a capacity standpoint, barged LNG provides a near coast supply without the climate-based risks associated with Hurricane Sandy-type events. With advanced notice of a storm, the FSRB can be easily transported away from coast and returned to supply gas immediately after the storm without the risk of damage to the FSRB or the underwater pipe it connects with. In some respects, an FSRB offers more reliability than a coastal facility as storm damage can be avoided. The barge will be crewed and dispatched on site during the heating season by National Grid’s planners to standby like any other commercial vessel.

Requirements for Implementation

Currently, the total lead time for delivery is approximately two years. The USCG permitting process is anticipated to take 1-2 years which includes the local permits identified above. The barge would not be ordered, nor seasonal construction of the connection until permits were secured. The entire project is expected to take 3-4 years from start.

Permitting, Policy, and Regulatory Requirements

Permitting the barge would follow the USCG process resulting in an approved WSA. As the lead Federal Agency, the USCG seeks stakeholder input from state agencies responsible for managing Federal Laws. The Rhode Island DEM would likely review the project for a Water Quality Certificate and the RI Coastal Resources Management Council would review the project for coastal zone impacts. Local construction permits are expected as well.

Environmental Impact

The only construction that would be required is a short pipe connection to a shore connection point. The resulting facility will be an underground pipe connection to the existing gas system.

A horizontal directional drill (HDD) will be required from the land connection to an area away from the near coast. This method is common to avoid erosion and disruption of the coastal zone. The depth of the pipe using the HDD will protect both the pipe and the environment by eliminating erosion potential. Temporary impacts of an HDD include the need for a pipe laydown area and the excavation of the drill site. Companies that specialize in coastal HDD activities use approved methods to receive the drill (such as gravity cells) and prevent temporary sedimentation of the water. Once completed the drill pulls the gas main back to the initial hole. Any extension of the gas main would be built out from the water end of the new pipe using permit approved methods to bury the pipe in the seabed. The last section of pipe would include a valve system and flex pipe anchored to the sea floor. This flex pipe would be lifted onto the deck of the barge for connection when the barge arrives on site. The underwater construction would result in temporary impacts including decreased water quality and sediment introduced into the marine environment, noise, and waste generation. The land side construction would be isolated to the drill location and connection to the existing main. Typical impacts include temporary increased stormwater runoff, noise, and air pollution from construction equipment. All these impacts would be mitigated by control measures during construction.

Once operational, there would be limited impacts from the transport of LNG by barges. While these vessels would disrupt ecological habitat, most of their operation would occur in well-used marine space and are no different than any similar sized commercial vessels.

Community Impact / Attitudes

Since the barge would be moored offshore in the winter months, there would be minor visual impacts from the sight of the barge on water views. Additionally, there may be potential loss of waterside recreation use when the barge is on site in the immediate area due to the security perimeter protocols developed during the siting process. Stakeholder impacts of the security zone (typically 500 yards) will be a consideration when identifying the specific mooring location. Given the summer tourism and commercial season on Aquidneck Island, construction of the tie in pipe would be planned for the offseason.

Summary

The table below summarizes the assessment of the option to use LNG Barges as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 11: Summary of LNG Barge Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Flexible near shore option providing the benefits of LNG peaking with minimal safety impact potential. Emerging market with potential to uniquely support capacity constraint.
Size	12,000 Dth/day	Capable of serving the 2035 peak daily need (gap) of 4,850 Dth/day & 300 Dth/hr
Timeframe	---	~ 4 years
Safety & Reliability		
Safety	---	A thorough safety analysis is provided by the applicant and approved by the USCG taking into account numerous specific scenarios including but not limited to terrorism and accidents. A properly designed offshore location fully mitigates public safety concerns.
Reliability	◑	Only limitation would be a disruption in supply over the water. Once on station, the barge is sized to support 10 full days of supply, at-sea replenishment responsibility of supplier.
Project Implementation & Cost		

Cost	◑	The annual cost of this option including, the tie in pipe, the reservation charge and commodity is expected to be ~$10M.
Requirements for Implementation	◑	Numerous, similar barges have been built worldwide and recently in US shipyards solving Jones Act concerns. Multiple reputable suppliers have expressed interest which would facilitate a competitive RFP. Construction of an offshore tie required for connecting to 99 psi system. Requires stakeholder support—without support, significant delays to deliver.
Permitting, Policy and Regulatory Requirements	◑	USCG is the governing authority. State permits for Section 401 WQC and CRMC approval for pipe construction from shore to water. Gubernatorial support required for successful WQC and CRMC approvals.
Environmental & Community Impact		
Environmental Impact	◑	Low impact to land, street connection to system required. Potential HDD to water with underwater main and shallow water integrated pipeline end manifold (PLEM). Siting lead by USCG process with local approvals through RI DEM and RI CRMC.
Community Impact / Attitudes	◑	On surface, mention of floating LNG likely to garner negative stakeholder response based on previous efforts to build import terminals at Providence & Weavers Cove. Significant stakeholder efforts required to educate stakeholders on this different delivery method. Option has much less safety impact and permitting challenges than land-based LNG operations due to well established USCG Waterway Suitability Assessment (WSA).

8.6. AGT Reinforcement Project

Overview

Aquidneck Island receives its gas pipeline deliveries through the Portsmouth take station, which is at the downstream end of the AGT G-Lateral system. The Portsmouth delivery point on Aquidneck Island connects to AGT via AGT's single 6-inch main crossing the Sakonnet River.

There is no specific project proposed by AGT at this time. The Company and Algonquin have been exploring the possibility of pursuing an infrastructure enhancement project to mitigate the potential delivery challenges that could arise with AGT's gas delivery to the Portsmouth delivery point because of the potential constraints caused by AGT's 6-inch main.

A system reinforcement project might construct new main to Aquidneck Island and related investments on other affected areas on the AGT G-lateral, which would reduce the potential for delivery constraints and, thereby increase the reliability of the gas capacity to Aquidneck Island. A system reinforcement project would likely involve investments that would also benefit Massachusetts gas customers.

An AGT project could also have a broader scope and be designed to provide additional gas capacity to meet growing customer demand on the part of National Grid in Rhode Island as well as other gas utilities that take service from AGT in Massachusetts.

Size

An AGT project focused only on system reinforcement would not provide additional gas capacity to Aquidneck Island directly. However, the Company expects that such a project would enable it to shift contracted capacity from upstream take stations on the G-lateral to Portsmouth on Aquidneck Island if it were available. That means that the capacity constraint on Aquidneck Island could be addressed by reducing demand upstream (or increasing local low-carbon gas supply upstream) or by reducing demand on Aquidneck Island.

An AGT project that addressed broader regional needs for Rhode Island and Massachusetts would likely create additional gas capacity to meet the supply constraint on Aquidneck Island and elsewhere in Rhode Island, but there is no detail yet on such a project.

For the purposes of this study, the Company assumed that an AGT project of limited scope focused on system reinforcement would not address the capacity constraint need on Aquidneck Island itself but would need to be paired with incremental demand reductions.

Cost

While there is no actual AGT project proposed at this point for which to present cost information, based on recent pipeline projects in the northeast, it is estimated that a system reinforcement project could have a cost of roughly $15M a year in terms of the Rhode Island share if other AGT customers are to participate in the project (absent this, cost could range higher to approximately $30M a year), with a cumulative cost (including interim portable LNG but excluding additional demand side measures) of ~$180M by 2035. That cost would be paid for by Rhode Island gas customers via a contracted rate with AGT for pipeline service.

Safety

An AGT project's plans, development, operation, and maintenance would be reviewed by the Pipeline and Hazardous Materials Safety Administration (PHMSA)—a US Department of Transportation agency responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of pipeline transportation.

Reliability

Historically, AGT and similar pipelines serving the Company have been very safe and reliable. The overwhelming majority of the Company's gas supplies are delivered reliably via the interstate pipeline network. Disruptions such as valve malfunctions on the pipeline systems can occur but are rare. Modern pipeline technology is designed to withstand a variety of environmental and man-made conditions. Above ground weather events (e.g., blizzards, hurricanes) and man-made events (e.g., traffic, automobile accidents) would not impact availability of the natural gas capacity.

An AGT project would provide a reliability benefit for Aquidneck Island compared to existing infrastructure, particularly by mitigating the risk of a single point of failure on the six-inch main that crosses the Sakonnet River.

Requirements for Implementation

The lead time for an AGT project is at least four years. If it were to move forward with an AGT project, pursuant to the Company's agreement with its regulators, the Company would execute one or more Precedent Agreements with AGT, subject to review with the Rhode Island Division of Public Utilities and Carriers. AGT would complete final engineering and other studies and begin the FERC application process as well as applying for other necessary permits. Upon receipt of required approvals and permits, construction would then commence. The Company does not expect an AGT project to be in service before the fourth quarter of 2024.

In order to begin construction of an AGT project, AGT would be required to satisfy all conditions precedent in an agreement with the Company, including the receipt of its FERC Certificate and any and all necessary governmental authorizations, approvals, and permits required to construct and operate the facilities.

Permitting, Policy, and Regulatory Requirements

AGT and National Grid teams (on behalf of both Rhode Island and Massachusetts customers) continue to discuss the potential for an AGT project to meet gas capacity needs in both states. If AGT proposes a project and the option evaluation effort in Rhode Island supported by this study and similar option evaluation for Massachusetts determine that an AGT project is the best alternative for Massachusetts customers, National Grid will seek regulatory approval of a pipeline contract in each state. In Massachusetts, Boston Gas will file a Precedent Agreement with the Massachusetts Department of Public Utilities (DPU) for review of the project. That review process typically takes nine months from the date of filing. Narragansett Electric will submit a Precedent Agreement to the Rhode Island Division of Public Utilities and Carriers for review at least six months before the date by which it is seeking approval. If the DPU approves the project, then Narragansett Electric will seek the Division's express support of the Precedent Agreement and associated costs, which Narragansett Electric would recover through a future Gas Cost Recovery filing with the Rhode Island Public Utilities Commission.

Once AGT receives commitment from the required gas utilities for their participation in a project, which could be more than just National Grid in the case of an AGT project that addresses regional needs, AGT will seek receipt of its FERC certificate and any and all necessary governmental authorizations, approvals, and permits required to construct and operate the facilities contemplated by the AGT project.

Environmental Impact

As part of the Permitting, Policy and Regulatory Requirements described above, AGT would be required to complete an environmental assessment for the AGT project which would address GHG emissions and climate change as well as proposed mitigation techniques associated with the project.

Community Impact / Attitudes

Without specifics on an AGT project in terms of the type of pipeline investments, their scale, and their location, it is difficult to assess community impacts from initial construction of the project. However, pipeline assets are typically not visible to the public, which might limit community impacts compared to LNG options.

Summary

The table below summarizes the assessment of an AGT project as a means of meeting the capacity constraint and vulnerability needs on Aquidneck Island.

Table 12: Summary of AGT Reinforcement Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Scope not yet determined, but could range from system reinforcements to address capacity vulnerability to broader project to address regional gas capacity needs in Rhode Island and Massachusetts
Size	N/A	Depends on project scope. A limited system reinforcement project scope would allow for capacity on AGT to be shifted downstream to Portsmouth take station; for purposes of this study, the Company assumed a limited AGT project that would not directly address capacity constraint but would be paired with additional demand side options.
Timeframe	---	To be scoped.
Safety & Reliability		
Safety	---	Historically, interstate pipelines have operated safely; safety is regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA)—a US Department of Transportation agency.
Reliability	●	Historically, interstate pipelines have been highly reliable; as fixed, largely underground assets, they are not subject to some risks that affect other gas capacity options.
Project Implementation & Cost		
Cost	◔	Cost will depend on the ultimate project scope and whether multiple gas utilities participate in the project; current estimate is ~$15M a year (though no project is currently proposed).
Requirements for Implementation	◑	The Company would need to obtain regulatory support in Rhode Island for a long-term contract with AGT and contract approval would be required for any participating Massachusetts gas utility. AGT would need to get a FERC certificate and any permits required for construction.
Permitting, Policy and Regulatory Requirements	◑	See above.
Environmental & Community Impact		
Environmental Impact	◑	An environmental assessment would need to be done by AGT before it could be approved.
Community Impact / Attitudes	◑	Any potential constructions impacts are yet to be determined, but ongoing community impacts would likely be lower than portable LNG.

8.7. Incremental Energy Efficiency

Overview

National Grid will build upon its existing nation-leading energy efficiency programs with a targeted and more aggressive program offering that reduces annual energy consumption and design day demand on Aquidneck Island. The nature of this initiative will be the utilization of enhanced, geographically targeted incentives and customer outreach and engagement approaches that emphasize robust and aggressive natural gas efficiency savings, with a key focus on a set of intensive weatherization and HVAC measures for both residential and commercial customers.

The magnitude of the gap between design day demand and natural gas capacity in the near- and medium-term will require extensive customer and trade ally engagement and training, door-to-door neighborhood campaigns, and customer concierge and financial and contractor coordination services to help facilitate increased adoption of efficiency measures. These efforts will need to be sustained throughout the forecast period in order to sustain incremental adoption by a declining remaining addressable market. In addition, this will require localized, dramatic increases in incentives offered to participating customers. While for the purposes of this study these costs and efforts are considered to be purely incremental, as a practical matter these efforts will likely have the effect, in the near term, of displacing implementation efforts from other parts of the state in order to increase delivery capacity of energy efficiency on Aquidneck Island. Over the long-term, these costs could also have the impact of displacing more cost-efficient spending on the pursuit of energy efficiency measures elsewhere in the state, having the statewide impact of reducing the overall adoption of energy efficiency measures and those measures' resulting benefits.

In lieu of funding these incremental expenses through the Company's statewide energy efficiency plans, an alternative approach would be to request funding for this initiative as a "non-pipes alternative" project, under the System Reliability Procurement mechanism as provided for in the State's recently revised Least Cost Procurement Standards.[25] In this option, which could also encompass demand response and electrification, the delivery of incremental energy efficiency projects on Aquidneck Island would still be coordinated with the energy efficiency programs and rely on many of the same delivery channels. Notably, customer collections to fund this investment would also be collected through the same System Benefit Charge (the "SBC surcharge") that also funds statewide energy efficiency programs.

Size

The size of the energy efficiency resource was built from an analysis of data from the recently completed Rhode Island Market Potential Study.[26] This study presented three levels of achievable energy efficiency for the 2021-26 time period: low, mid, and max. Two scenarios were created for energy efficiency savings in this study: a moderate scenario (the difference between the potential study mid and low cases) and an aggressive scenario (the difference between the potential study max and low cases). Amounts of efficiency savings related to these scenarios were blended into the various solutions modeled for this analysis. Up to six years may be needed to ramp up to sustained levels of participation in both scenarios.

The range of design day Dth/day presented below are incremental over current baseline amounts of efficiency and are achieved by increasing customer participation and/or by reaching higher levels of savings from customers who were already expected to participate. Annual savings per customer were adopted from recent National Grid historical data and increased by 10% in the moderate scenario and 25% in the aggressive case. These annual savings are then converted to design day savings using a design day factor of 1.3% and adjusted to wholesale

[25] See, for example, pages 1 and 2 of the revised standards in Docket 5015, accessed at http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards%20Draft_5-29-2020.pdf, amended as recorded by Open Meeting minutes of July 23 at 1 pm, accessed at http://www.ripuc.ri.gov/eventsactions/minutes/Minutes%20July%2023,%202020%20PM.pdf

[26] https://rieermc.ri.gov/rhode-island-market-potential-study-2021-2026/

savings values using a factor of 102%, which is slightly higher than the lost and unaccounted-for gas (LAUF) to match the factors used in the demand forecasts.

Depending on the level of EE incorporated into the various solutions, the adoption of energy efficiency measures results by 2035 results in up to ~35% of commercial customers and ~80% of residential customers on Aquidneck Island participating in the baseline and incremental HVAC upgrades and/or weatherization programs. Some customers are expected to have completed both weatherization and HVAC upgrades while some will do only HVAC upgrades.

The aggregated savings from this initiative across all customers leads to an annual incremental savings as a percent of sales between 0.3% and 0.6%. When combined with base goals currently being modeled by National Grid for its 2021-23 Three-Year Energy Efficiency and Conservation Procurement Plan, this implies a maximum savings as a percent of gas sales of 1.4% to 1.7% in the Aquidneck communities. More details on savings and participation assumptions for efficiency may be found in the Technical Appendix.

Cost

The NPV of energy efficiency costs ranges from $5 million to $16 million depending on the solution. Costs are a combination of aggressive incentives paid to customers, administrative costs, and customer costs for installation costs not covered by incentives and, in some cases, remediation of pre-weatherization barriers.

- Incentive costs per MMBtu are based on data from the Market Potential Study. As assumed in the Rhode Island Market Potential Study, a substantial increase in the rate of customer adoption of energy efficiency measures will require equally substantial increases in the incentives offered to all customers. 2019 costs are escalated to 2021$ using a 1.5% escalation rate and escalated forward from 2021 using an assumed annual inflation rate of 2%.
    - The most aggressive energy efficiency scenarios assume that all customers receive incentives that cover 100% of the incremental cost of the assumed implemented energy efficiency measure. In reality, it is likely that some portion of the assumed incremental volume of participating customers in the most aggressive scenarios could be induced to adopt measures at some incentive level between current incentives and the assumed 100% of incremental cost incentive. Energy efficiency programs are typically ‘standard offer’ programs, however. The Company has limited ability to price discriminate and offer differential incentives to different customers based on assumed or observed customer economic requirements. While it is likely that some fraction of the incremental energy efficiency in the maximum scenarios could be achieved at a greater than proportional cost reductions, the Company has no basis on which to estimate this relationship, and any reduction in assumed energy efficiency contributions would either require additional electrification and/or a deferral of the phasing out of portable LNG at Old Mill Lane. As such, for the purposes of this study, the Company based estimated energy efficiency costs on the 100% incremental cost incentive assumption, and would anticipate continually evaluating and refining incentive levels and all other go-to-market strategies and approaches over the 15 year time frame over which incremental energy efficiency measures and participation are assumed in order to maximize the cost efficiency of the portfolio of delivered solutions.

- Administrative costs were added such that 9.5% of the total implementation costs were attributable to administrative costs. This is in line with data from National Grid's 2019 Year End Report.
- For solutions including moderate energy efficiency, customers would be responsible for paying for the portion of project costs not covered by incentives. Based on historic program data, the portion covered by incentives ranges between 70% and 95% for the proposed incremental measures. To account for the customer contribution, utility incentives are divided by the appropriate percentages for the selected measures to determine the full incremental equipment installation costs for the selected solution. In aggressive scenarios, there is no customer contribution because the incentive covers 100% of the incremental installation cost.
- In order to achieve the greater levels of participation and savings, pre-weatherization barriers such as removal of asbestos and/or knob-and-tube wiring will need to be addressed. To account for remediation of pre-weatherization barriers, a cost premium of approximately 7% is added across residential and C&I installation costs. There is minimal data about the need for pre-weatherization remediation for commercial installation. The addition of the cost premium based on residential pre-weatherization remediation is therefore a conservative assumption.

Safety

Like any customer service offering, safety is increased with proper participant and trade ally education, awareness, and training. Only contractors licensed by the State of Rhode Island can install equipment or provide services offered through the EE programs. National Grid will need to work with state and local government, educational institutions, and industry partners to expand the existing trade ally network and include extensive trade ally training. In addition, as part of intensive energy efficiency projects, it will be important to continue to utilize safety and quality control procedures adhere to statewide standards in reviewing statistically valid samples of projects to ensure safety and quality standards are being met. The need for an expansion of these efforts contributes to the estimated increase in administrative costs to deliver this initiative.

Reliability

Weatherization and HVAC efficiency installations will lead to passive energy and design day savings. Once installed, an EE measure typically requires no action on the part of the building occupant for savings to persist and be a reliable source of gas demand reduction. (The exception to this is controls-related savings, which depend on users' behavior.) Like other EE programs, National Grid will need to verify measures are installed and savings are achieved. In addition, information from evaluation, measurement, and verification (EM&V) efforts will inform changes to program design to tailor the selection of which measures are installed and the targeted number of homes and buildings on Aquidneck to realize the targeted design day savings.

Permitting, Policy, and Regulatory Requirements

National Grid will require Rhode Island PUC approval for the enhanced efficiency and weatherization programs, incentives and total investments before these can commence, as with all EE filings made pursuant to Least Cost Procurement; deployment of these initiatives would be dependent on their being included in those filings.[27] If a System Reliability Procurement investment is chosen as the pathway, that proposal may be filed at any time. Under current protocols, National Grid will need to provide updated cost and benefit estimates for these programs as part of future annual regulatory approval processes.

The magnitude of the energy efficiency program envisioned will impact permitting, policy, and regulatory activities at the local and state level.[28] At the local level, contractors will be responsible for obtaining local permits for the retrofits of homes and businesses. Local permitting authorities will need to prepare for the increased volume of permit applications to address the weatherization efforts. Work will be required to streamline these application and approval processes to achieve program targets.

Requirements for Implementation

Because of the size of the near-term gap between natural gas demand and available capacity, the implementation of an incremental EE program will require a significant increase in the level of effort across the target area. For reference, the EE program would have to scale to approximately double the annual activity on Aquidneck Island by 2026. There will need to be growth in the number of qualified contractors for the design and installation of the measures, staff in local permitting offices, and increases in program staff for National Grid. There will also be a need for more investment in marketing, education and training to support these targeted efforts, and ensure they are launched and accelerated to increase adoption. As mentioned above, National Grid would have to work with stakeholders to develop a concerted strategy, including supplemental funding, to address pre-weatherization barriers and enable the required levels of participation, including training for safe handling and disposal of material removed during pre-weatherization activities

A key challenge for achieving the targeted savings will be the ability of National Grid to ramp up quickly and start realizing impact by the winter of 2021/22. This will require efforts to start as soon as possible to design, market, and rapidly expand programs to an unprecedented level during, we hope, the economic recovery following the ebbing of the coronavirus pandemic. The timing will be further complicated by the regulatory proceeding schedule for its 2021 energy efficiency plan, described in the next section. The number of customers who agree to participate in energy efficiency programs, and/or the impact of these programs on those who do participate, may not meet projections. This creates risk of not achieving the full projected potential on peak days. Reliability could improve over time as the targeted approach is implemented and matures.

In addition, there will need to be a high level of coordination of agencies and utilities to manage program design and implementation in the most effective manner possible. For example, state and local governments may consider approaches that focus attention on building energy efficiency through home energy ratings, further updating of building codes, and implementation of effective mechanisms for landlords of multifamily buildings to encourage comprehensive weatherization of all units in a building. National Grid will also coordinate with its electric utilities' efficiency programs.

[27] The Annual Energy Efficiency and Conservation Procurement Plan for 2021 is due to be filed on October 15, 2020. It will not be possible to design or budget for a geographically targeted initiative for deployment on Aquidneck Island prior to that filing.

[28] Code changes or laws to require more efficient boilers or restrict the use of natural gas may occur over the life of this initiative but are not accounted for. In those cases, the amount of gas demand reduction is assumed to be the same as modeled here. If the demand reduction is achieved with fewer incentives, the overall utility implementation cost will decrease while overall RI Test installation costs would be the same.

Environmental Impact

The ecological impact of the energy efficiency program will be minimal. The program will not result in new potential for risk that may harm the environment; in fact, it may reduce risks as new equipment replaces existing, and as efficiency improves the health, comfort and safety of buildings. Materials selected for the efficiency and weatherization activities will be compliant with all state and local environmental regulations and contractor training will include environmental considerations.

As highlighted above, the pursuit of higher cost to achieve savings (either as a result of increased incentives or greater required marketing and customer engagement efforts to pursue customers with an otherwise lower propensity to consume energy efficiency services than might exist elsewhere in the state given lower assumed market penetration rates in those other areas of the state) on Aquidneck may negatively impact the Company's ability to achieve greater levels of energy efficiency savings (and the resulting environmental benefits) from lower cost to engage customers elsewhere in the state.

Community Impact / Attitudes

National Grid has conducted successful community initiatives on Aquidneck Island in 2010/11 and in 2019. These featured community-focused marketing, engagement of local officials, and a community challenge goal. Both of these efforts show that the communities on Aquidneck Island can successfully be engaged in targeted ways to support energy efficiency.

Intensive incremental HVAC efficiency and weatherization effort will further develop the ecosystem that includes a wide range of contractors and suppliers who will need to hire additional employees to support the investments in energy efficiency over the duration of the program. A significant portion of these investments will go directly into the local economy. In addition, bill savings from the energy efficiency measures will allow consumers to spend some portion of this savings within the local economy.

Summary

The key assumptions defining the savings and costs associated with the option of an incremental energy efficiency program as a means of meeting the capacity and contingency need on Aquidneck Island are summarized in the table below.

Table 13: Summary of Incremental Energy Efficiency

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Deliver incremental amounts of energy efficiency by providing higher levels of incentives to more customers and/or delivering even more efficient HVAC and weatherization technologies to achieve greater amounts of savings which are coincident with the peak day.
Size	936-1775 Dth/day	936 to 1775 Dth/day cumulative demand reduction by 2034-35 based on cumulative participation of up to 35% of businesses and 80% of homes.
Timeframe	---	Generally, ramp up over 6 years to 2026-2027, delivering sustained amount of participation and savings from then for duration of 15-year period.
Safety & Reliability		

Safety	---	Installation and operation of energy efficiency measures in homes and businesses is performed by qualified contractors. Once installed, equipment is very safe for occupants to operate.
Reliability	◕	Once an EE measure is installed, no incremental action is required on the part of the building occupant for savings to persist and be a reliable source of gas demand reduction. (The exception to this is controls-related savings, which depend on users' behavior.)
Project Implementation & Cost		
Cost	◕	The NPV of EE cost ranges from $5 to $16 million depending on the solution and includes implementation and incentives, administrative costs, and expenses not traditionally included in EE, such as remediation of pre-weatherization barriers.
Requirements for Implementation	◑	Energy efficiency from weatherization and HVAC improvements have a proven track record of providing gas savings, coincident with the peak day. National Grid has a very good track record of meeting its savings goals in Rhode Island. The key consideration is whether the strategies, outreach, education, incentives and training envisioned for Aquidneck Island will be successful in securing the needed amount of participation to achieve incremental amounts of savings. There are established regulatory and implementation pathways for energy efficiency. The ability of the contractor network to scale up and to be trained to deliver incremental amounts of energy efficiency needs to be demonstrated. Training needs to include safe handling and disposal of pre-weatherization materials.
Permitting, Policy and Regulatory Requirements	●	Energy efficiency programs must pass the Rhode Island Benefit Cost Test as detailed in Docket 4600 and in the Least Cost Procurement Standards recently adopted in Docket 5015. The incremental budgets necessary to achieve extra savings will undergo stakeholder and regulatory scrutiny, similar to every other solution.
Environmental & Community Impact		
Environmental Impact	●	Materials and construction used for energy efficiency installations typically have minimal additional environmental impact if they are handled and disposed of properly. If statewide levels of EE are reduced by concentrating resources to deliver higher marginal cost and effort EE on Aquidneck, overall environmental benefits could be reduced.
Community Impact / Attitudes	●	Aquidneck Island has been very receptive to community-specific initiatives featuring energy efficiency, in 2010/11 and 2019. Engagement has been very positive and

		successful. The impact that the coronavirus pandemic economic recovery on this historic attitude is unknown.

8.8. Gas Demand Response

Overview

Gas Demand Response (DR) involves customers reducing the amount of natural gas that they consume over a specific period of time, typically a few hours or a whole day. This reduction can be achieved either through reducing energy needs (e.g. lowering thermostat temperatures, reducing manufacturing output) or through the use of an alternate fuel source to meet the needs (e.g. fuel switching). If the customer population can participate in DR programs without the need to install additional equipment, gas DR can be ramped up quickly. DR can also be cost-effective when compared to other solutions because, though it often pays a higher rate per unit of reduced demand, 100% of the demand reduction occurs during high demand periods.

This option encompasses two types of programs – 1) DR for commercial customers and multi-family buildings, and 2) thermostat direct load control ("bring your own thermostat," or BYOT) programs for residential heating customers. The total technical potential for these programs is limited by the customer population on Aquidneck Island and by the ability of customers to participate in these types of programs.

National Grid has been running a C&I gas DR pilot in Rhode Island for the past two winters. Four participants in that program are located on Aquidneck Island, which has revealed useful information about customer interest in participating in a DR program. However, the total C&I population on the island is limited meaning that signing up a few sites may not represent significant untapped potential.

In parallel, BYOT programs can be used to reduce thermostat set points to reduce consumption of residential heating customers during peak load hours and, potentially, over the course of peak load days. The number of eligible smart thermostats in the region continues to increase in response to incentives. A BYOT program would create additional value for customers who have adopted the use of smart thermostats by offering a performance-based incentive.

The Company is considering a hybrid demand response/electrification alternative for fuel-switching programs to allow for the use of electricity rather than fuel oil as a backup fuel. In this case, heat pumps to meet site cooling loads could be installed. These systems would primarily be for increased cooling efficiency (and electric savings and associated environmental benefits), but they could also be used to provide electric heat and reduced gas demand through the heat pump on cold days. This option avoids some of the system sizing and operational challenges of sizing heat pumps to meet peak heating needs and offers positive environmental impacts. It needs further scoping and engineering to characterize as a viable option.

Size

To identify the C&I population on Aquidneck Island that would be eligible for a DR program, National Grid used a minimum threshold of 1,000 Dth of annual consumption. This yielded 239 accounts with a total design day consumption of 7,368 Dth. The top 25 of these accounts represent approximately 50% of this consumption. In the Company's modeled Non-Infrastructure approach, it assumed 100% participation in 2034-35 for the two largest customers; ~43% participation for the next 33 largest customers; and ~35% participation from the remaining 204 of the top C&I accounts. Other solutions (e.g. LNG at Navy site solutions) only assume participation from the largest customers.

For the BYOT program, the entire residential population could theoretically be eligible for participation in the program if they have a smart thermostat. The modeled Non-Infrastructure approach assumes 24% participation in 2034-35.

Cost

DR programs would have relatively low costs for reducing forecasted design day demand due to the fact that reductions only occur on peak demand days. For both types of demand response programs, the costs would be annual implementation and evaluation costs as well as performance incentives for customers. DR programs can be structured as either tariff rates or as standalone programs that work with existing rate structures.

In addition to program costs, firm DR customers who elect to use a backup fuel to reduce their peak-load day gas needs incur the cost of maintaining and potentially purchasing alternate fuel systems that they can call upon during a DR event when they must switch from natural gas. BYOT program participants should have minimal additional costs as their participation usually will not require any alternative fuel.

The Company's modeled Non-Infrastructure solution assumes reservation charges of ~$175 / Dth, performance incentives ranging from $35-$75 Dth/year for C&I customers, as well as additional program costs and upfront costs (for instance, where a dual-fuel system needs to be installed), in addition to incentives to offset upfront customer costs listed above.

NPV of costs is estimated at ~$9M for the Non-Infrastructure solution (ranging down to $2M for solutions such as a Navy LNG site paired with incremental DSM); this reflects annual costs of $0.2-$1.4M.

Safety

The safety matters to address for DR participants relate to maintaining safe conditions in their facility if they do not use an alternative fuel or safely holding and utilizing a backup fuel at their site for those that switch to a backup. If the backup fuel is a delivered fuel, these fuels must be transported and delivered safely, and deliveries may be necessitated during prolonged cold spells with multiple DR events called.

For the residential customers participating in the BYOT program, there are not expected to be any significant safety issues. National Grid has successfully worked with its partners to administer summer and winter BYOT programs.

Reliability

The programs described above are DR programs for firm customers. These differ from interruptible (non-firm) rates offered by National Grid, which require that customers be curtailed (i.e. not delivered natural gas) on peak demand days. Firm DR programs are for firm customers who have a legal right to service on a peak demand day but who are voluntarily relinquishing their right to that peak day capacity. Since the operations of National Grid will be adjusted based on this new allocation, it will be critical that these customers perform during all DR events. Most non-firm rates, including those offered by National Grid, require that customers maintain a minimum level of backup fuel supply, typically certified using an affidavit. Firm DR programs generally do not have the same sort of requirement, placing the responsibility for ensuring that sufficient backup fuel is available with the customer. The reliability of participation in firm DR programs, especially during design day-type temperature conditions, is an area of interest and investigation given the relatively early day of gas demand response programs for the industry. If data indicate that reliability levels are lower than expected, it may be necessary to modify the programs, such as adding an affidavit for backup fuels, to ensure that National Grid can rely on DR as a resource to meet peak load day requirements.

Demand response can be an attractive way to reduce peak day consumption. However, current program structures allow customers to override the event and use gas. Additionally, meeting customer enrollment requirements will be critical. The number of customers who agree to participate can fluctuate or not meet projections. Therefore, there is risk of not achieving the full projected potential on peak days. Reliability could improve and become more predictable over time as programs mature.

Requirements for Implementation

Incremental programs as discussed above will need to be reviewed and approved. Thermostat setback programs of the size contemplated will require continued aggressive adoption of smart thermostats by residential customers.

Permitting, Policy and Regulatory Requirements

Since demand response does not exist in Rhode Island beyond the scale of a pilot, it would be necessary to file for approval of a new program, whether tariff-based or standalone, to establish the program structure and to determine the appropriate method for cost recovery.

Some customers who participate with a backup fuel may need to update their air emissions permitting due to changes in their emissions profile. Additionally, where commercial and industrial customers would be installing a backup fuel source that is more emissions-intensive than natural gas (e.g. on-site oil storage), there may be additional permitting or regulatory complexity for them.

Environmental Impact

The local environmental impact of the C&I demand response program will depend on the number of backup systems that need to be installed. If few systems are installed, the impact will be minimal as participants who either have a backup system already or who will participate without one will only be changing their behavior. If many systems need to be installed, the local environmental impact will be more pronounced.

Fuel-switching programs which replace gas with a backup fuel could increase local emissions during a demand response event.

Rhode Island has ambitious targets to reduce greenhouse gas emissions in the coming decades. Using delivered fuels, especially fuel oil, as an alternative fuel during peak-load days will usually result in increased greenhouse gas emissions relative to a scenario where natural gas is used all year. As part of developing firm DR programs, National Grid will explore providing incentives or support the procurement of alternative fuels, such as biofuels or supplemental electrification.

Community Impact / Attitudes

The community impact is limited for the demand response programs due to the fact that the systems are contained within existing facilities. If C&I customers are participating with a delivered fuel as their backup, it might result in additional truck traffic from fuel deliveries through the community depending on the number of demand response events and how that compares to the on-site storage capacity maintained by participants.

Summary

The table below summarizes the assessment of the option to utilize gas demand response as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 14: Summary of Gas Demand Response Option
● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Potential to establish daily or multiple-hour reduction (load-shedding) program by working with C&I customers that have or are willing to utilize a backup fuel. Voluntary residential participation in BYOT (bring your own thermostat) direct load control programs may be a supplement to help to meet peak hour needs.
Size	500-1,900 Dth / day	Based on ability to scale to top C&I customers (35%+ participation), which drives majority of capacity. For the DR capacity modelled in this study: • 500 Dth/day = DR capacity paired with Navy site / Barge approaches where only the top C&I customers are enrolled. • 1,900 Dth/day = approaches with more aggressive gas DR where smaller C&I customers drive additional capacity savings.
Timeframe	---	1-2 years for program establishment, assuming regulatory approval proceeded quickly; customer enrolment will build over time and likely take much longer to scale, depending on incentives and customer participation.
Safety & Reliability		
Safety	---	For C&I customers, three areas regarding safety must be monitored: 1) ability to safely manage facilities when gas is curtailed: 2) safe maintenance and operation of backup fuel equipment; 3) safe delivery and receipt of fuels. For residential customers, no significant safety issues are expected.
Reliability	◔	Reliability depends on customers performing as obligated during demand events; for firm customers, who voluntarily reduce gas usage, this is especially key. Reliability on design day should be further investigated; program could be modified if research suggests design day/hour reliability is lower than expected.

		Similar to LNG or CNG, customers that rely on trucked fuel (e.g. fuel oil) to reduce their gas usage could be at risk for weather events. As it is relatively new in the gas utility industry, gas DR is largely untested on design day-like conditions, so it lacks a track record of reliability (as compared to interruptible gas tariffs or electric DR programs). However, over time, with a longer track record and program refinements, the reliability rating could improve.
Project Implementation & Cost		
Cost	◑	Program cost is low relative to some solutions (including current interruptible programs, for which customers are interrupted at higher temperatures and thus far more frequently); however, program costs continue indefinitely while the gas DR capacity is needed for reliability. Some C&I customers would need to install new backup systems, which would pose additional cost. NPV through 2034/35 of gas DR programs costs as modeled in this study range from $2M-$9M, depending on scale of program.
Requirements for Implementation	◕	The Company knows how to deploy DR programs and has some experience doing so via pilot in RI and from program experience in other service territories; four pilot C&I customers are on Aquidneck Island. Thermostat setback programs will require continued aggressive adoption of smart thermostats by residential customers.
Permitting, Policy and Regulatory Requirements	◑	Gas DR has generally been supported by regulators and stakeholders but does not exist in Rhode Island beyond the scale of a pilot, so approval for a new program would be necessary. There may be concern from some stakeholders about gas DR's alignment with Rhode Island's decarbonization goals due to the typical use of fuel oil as the backup for customers switching off natural gas during DR events. Additionally, C&I customers using fuel oil might need to update their air emissions permitting if their emissions profile changes. Fuel-switching program could see challenges where commercial customers do not already have backup fuel on site (i.e., would need to install oil storage).
Environmental & Community Impact		
Environmental Impact	◑	Some potential environmental impact for C&I installations of backup fuel oil systems. Residential BYOT programs should have no negative impacts.
Community Impact / Attitudes	◕	Assuming that the emissions impact can be addressed and that the number of events doesn't result in significantly increased truck traffic from fuel deliveries, this option is relatively unobtrusive. In addition, DR incentives can serve to reduce participating customers' overall bills.

8.9. Heat Electrification

Overview

Another opportunity for reducing design day natural gas consumption is by converting customers' space heating energy source from natural gas to electricity via electric heat pumps—either converting existing gas customers or diverting new construction or would-be oil-to-gas conversions to electric heating. There are multiple technologies and approaches heat electrification—i.e., air-source heat pumps (ASHPs), ground-source heat pumps (GSHPs, or geothermal), and district energy systems. For the purpose of modeling and analysis for this study, the Company assumed all heat electrification would be achieved via ASHPs because they tend to be the most widely adopted heat electrification option based on cost and ease of adoption. However, the real-world heat electrification market has multiple technologies in play, and National Grid expects that an actual heat electrification program for Aquidneck Island could include a role for options other than ASHPs, which are described in more detail in a subsection below.

Heat electrification via ASHPs could be achieved using cold climate heat pumps, which operate efficiently even at low outdoor temperatures. Advances in technology over the past decade have led to the development and successful implementation of cold climate heat pumps across the United States. If they are sized correctly, these cold-climate heat pumps may be installed and operated without a fossil fuel backup heating system in residential, commercial, and multi-family properties. Heating electrification is best when paired with weatherization to ensure proper system sizing.

For the heat electrification initiative modeled in this study, National Grid would provide incremental incentives and coordinate customer and trade ally awareness, education, marketing, and promotion of cold climate heat pumps focused on:

- current residential and small commercial customers whose existing heating systems may be in need of replacement at the end of their useful lives[29]; and
- customers within 100 feet of the gas main, who do not currently heat with gas, but might otherwise consider switching to gas for heating.

This initiative focuses on the conversion of gas-heated customers to electric heat. However, a meaningful portion of the peak demand reducing contribution from this solution will come from using heat electrification to displace the use of delivered fuels by customers who currently rely on oil and propane for heating but might otherwise connect to the gas system over the forecast window of this study. Funding and providing incentives for heat electrification for these customers will require a long-term regulatory pathway that does not currently exist in Rhode Island.

Size

National Grid assumes that once a customer installs an electric air source heat pump, they will not retain natural gas heating as a backup. However, some of those customers may choose to keep natural gas for other end uses, like cooking. It is assumed that electrification will reduce customer's design day demand by 95%. As noted previously, the potential market includes current gas customers considering replacement of their current gas heating or prospective gas

[29] The compatibility of existing in-home distribution system and heat pump will also be a factor: if the customer has a furnace and ducts already they will be a good central ASHP candidate; if they're on a boiler with hydronic system they would have higher costs to do the ducting for a central ASHP but could install ductless mini-splits as an alternative.

customers who had been planning on replacing their current heating equipment with gas heating equipment. Assuming 5% of customers consider replacing their heating equipment each year implies an annual potential of about 200 to 800 residential and small commercial customers, and contributes between 2,000 and 10,500 Dth / day, depending on the solution. More details on savings and participation assumptions may be found in the Technical Appendix.

Cost

The biggest drawback for electrification of gas-heated customers in Rhode Island is the cost – both upfront cost and ongoing operating cost. The upfront cost of a heat pump and installation is often twice as high as the typical natural gas heating unit for which it would substitute. Although heat pumps are very efficient, the difference between natural gas costs and electric prices are a key factor in customer economics. Switching from gas heating to electric heating is likely to lead to an overall increase in a customer's annual utility bills, even when accounting for the increased efficiency of electric heat pumps and the corresponding air conditioning savings for those customers to whom that applies. The cost for electrification would range from $25 million to $136 million depending on the solution.

While there are other factors that contribute to the current levels of heat pump adoption in Rhode Island, driving levels of adoption high enough to meet targeted gas savings requires overcoming these economic barriers. In practice customers may need an incentive that is higher than the incremental cost of the heat pump to not only compete with the lower-priced gas alternative but to also cover the increased energy bill after installation. As a program matures and electric and natural gas prices change, this will likely be subject to change. At this time, an upfront incentive equivalent to 100%-180% of incremental technology costs would be necessary to drive the 33% to 100% electrification annually of customers considering replacing current HVAC with gas heating that would be necessary in some of the solutions. At these incentive levels, there will likely also be some level of free ridership. This means that many of the customers that are expected to organically adopt heat pumps (e.g., they would install a heat pump even if there was not an incentive available) would now participate in the program, somewhat reducing the program cost-effectiveness. Further details on costs for this solution is included in the Technical Appendix. An additional potential cost of upgrading other appliances is not embedded in current incentive assumptions.

For this study, National Grid has modeled a programmatic approach to electrification that relies on incentives for customers to adopt electric heat pumps. In practice, Rhode Island could adopt a more codes- and standards-based approach that could mandate heat electrification. This would change the implementation requirements and would be a function of state and local government regulation. Such an approach would also have a different cost profile.

Safety

Like any customer service offering, safety is increased with proper participant and trade ally education, awareness, and training. Only contractors licensed by the State of Rhode Island can install equipment or provide services offered through the electrification program. As with energy efficiency solutions, National Grid will need to expand the existing trade ally network and include extensive trade ally training. In addition, as part of incremental electrification, it will be important to develop safety and quality control procedures and review a statistically valid sample of projects to ensure safety and quality standards are being met.

Reliability

Total electrification of customers' heating systems will reliably reduce forecasted design day gas demand. Electrification program design and forecasts for the gas peak demand reductions from electrification must account for the degree to which customers retain their natural gas service for non-heating end uses (e.g., cooking, water heating). To be part of a solution that ensures reliability on Aquidneck Island, a heat electrification program would need to scale up and meet targets, and this is considered under the implementation section below.

Requirements for Implementation

Because of the size of the near-term gap between demand and capacity, the implementation of the program will require significant startup costs and resources. For example, there will need to be growth in the number of qualified contractors for the design and installation of the heat pumps, an increase in staff in local permit offices, and increases in the number of program staff to initiate a new program. In addition, this type of program would require investments in marketing, training and broad on-going support to sustain the level of targeted program growth.

In addition, there would need to be a high level of coordination between agencies and utilities to manage program design and implementation in the most effective manner possible. For example, state and local governments should consider approaches that focus attention on building HVAC design through home energy ratings, further updating of building codes, and implementation of effective mechanisms for landlords of multi-family buildings to encourage adoption of heat pumps for application to all types of buildings.

Uptake of electrification may be slower than necessary to achieve the target gas savings if the projected levels of incentives required to drive customer adoption are not approved, or if customers do not see electrification as an attractive and viable alternative at the pace required to achieve timely adoption. There is also risk of achieving the desired levels of savings if the required contractor network is not developed soon enough to support installations. Reliability could improve over time as programs mature. Performance reliability of electric heat will be dependent on the reliability of the electric utility network, and its ability to manage additional volume from incremental heat pump adoption.

Based on our preliminary, aggregated review of summer and winter feeder capacity on Aquidneck Island, there is sufficient winter and summer capacity to accommodate heat electrification in the near term for the non-infrastructure scenario. However, location matters, and although there is sufficient capacity in aggregate, individual feeders, feeder sections or secondaries would likely experience loading that produces system thermal and voltage performance concerns. As the amount of heat electrification grows, addressing such concerns would require potentially significant incremental investment on the electric distribution system. Should heat electrification be part of the long-term solution for Aquidneck Island, National Grid, as the electric distribution utility for the island as well, would model increasing electric demand from heat electrification, identify electricity network impacts, and plan accordingly.

Permitting, Policy, and Regulatory Requirements

The design and magnitude of the incentive program that would be required to drive this high level of heat pump adoption would require policy initiatives, in particular to support conversion of gas-heated customers to electric heat and provide a mechanism for National Grid to offer the high level of both first cost and ongoing cost incentives to drive the target level of heat pump adoption. National Grid will require RI PUC approval for these programs, incentives, and total investments before they can commence. At the state level, National Grid would provide updated cost and benefit estimates for the magnitude of these programs to the RI PUC as part of a future regulatory approval process.

The electrification initiative will need to satisfy Rhode Island requirements for cost-effectiveness. Cost effectiveness has been demonstrated previously where significant benefits have been accrued by replacing inefficient air conditioning with a heat pump. Cost-effectiveness will need to be proven where the primary focus is on heat electrification. If the initiative is not cost effective under existing methodologies, it will require a different way of thinking about funding electrification incentives than has been used historically for energy efficiency programs.

If the option to include oil-to-electric heating conversion is included, as a means to reduce projected growth in the demand for natural gas on Aquidneck Island, National Grid will need to demonstrate that the allocation of costs and benefits from these conversions is fair. Previously, the RI PUC has not allowed oil-to-electric conversions to be supported by electric energy efficiency program funding. A program that drives gas customer benefits could be fundable through gas energy efficiency funds, but that may not be extensible to customers not heating with gas (i.e., current delivered fuel customers).

The magnitude of the electrification envisioned will impact permitting, policy, and regulatory issues at the local and state level. At the local level, contractors will be responsible for obtaining local permits for the retrofits of homes and businesses. Local permitting authorities will need to prepare for the increased volume of permit applications to address electrification efforts. Work will be required to streamline these application and approval processes to achieve program targets.

Environmental Impact

The local environmental impact of an electrification program, like the energy efficiency program, would be minimal. Air source heat pumps to be installed as replacements to existing systems will be compliant with all state and local environmental regulations, and contractor training will include environmental considerations. Implementing an electrification program will likely have slight benefits from an air quality perspective, as it will result in fewer homes and businesses in Rhode Island combusting fossil fuels onsite.

Community Impact / Attitudes

The intensive and unprecedented incremental gas-to-electric heat electrification program will create an entire ecosystem that will include a wide range of contractors and suppliers who will need to hire additional employees to support the spending over the duration of the program. A significant portion of these investments will go directly into the local economy. Due to the increased adoption of heat pumps for heating on Aquidneck, there would be growth in total electric customers and electric demand.

While the Aquidneck Island community has historically demonstrated a responsiveness to localized energy efficiency awareness and engagement initiatives, there is limited, if any, history of any community in the United States supporting or adopting the large-scale replacement of existing, functioning gas heating systems with alternative forms space heating in either residential or commercial and industrial settings. As such, electrification of heating as a component of a non-infrastructure long-term solution would require an unprecedented level of local community engagement and adoption of heat electrification, which, in addition to upfront effort and cost required, could lead to higher ongoing operating costs for customers.

Supplemental Electrification Approaches

For the purpose of making this study's analysis more tractable, the Company modeled heat electrification as exclusively relying on single-site air-source heat pumps. However, other promising avenues for electrification exist and merit further consideration and potential inclusion in any actual heat electrification program developed as a long-term solution on Aquidneck Island.

Ground-Source Heat Electrification: Ground-source heat pump systems, commonly referred to as geothermal systems, are a form of heat electrification where heat is exchanged with the ground via an underground loop field, a series of plastic pipes that carry a working fluid. Because of the stable temperature underground, there is more heat available during the winter and a greater ability to reject heat during the summer. This makes the heat pump that relies on the ground heat source/sink extremely efficient with coefficients of performance (COPs) of up to 6.0, which means 6 units of heating are extracted for 1 unit of input energy.

The efficiency of these units allows them to meet the year-round energy needs for a home without the need for a backup system. Most heat pumps used in geothermal systems do have a backup electrical resistance unit installed, but it often is not needed. This means that geothermal systems can be installed in lieu of a natural gas connection used for heating.

National Grid is exploring the potential for both single-facility loops and shared loops (i.e. loops that connect multiple different facilities that are often managed by independent economic entities). Single-facility systems are smaller and simpler to install given that there are fewer parties involved. Shared loops are larger and more complex, but they also create an opportunity for efficiency based on connecting customers with diverse energy usage profiles. Since geothermal systems function by exchanging heat, it is possible to collect waste heat (e.g. the heat that must be removed for refrigeration at a grocery store) from some customers and to provide that heat to others connected to the shared loop. In this scenario, both customers have their needs met and the total amount of input energy required decreases.

Given the relatively high density of buildings on Aquidneck Island, shared loops may be a good fit for those that are considering geothermal.

Geothermal systems have high upfront costs, with systems for single homes costing $30,000 to $40,000. This is offset by higher operating efficiencies, which can result in 15-20% lower energy bills according to a report on heat pump potential in New York by the New York State Energy Research and Development Authority (NYSERDA). The upfront capital costs faced by customers can be reduced by incentives offered by utilities and by efficiencies realized by utilizing shared loops between customers. There is a potential for a utility-owned approach to deploying geothermal, which could provide benefits to customers in terms of mitigating up-front costs and recognizing the energy network aspects of shared loops.

Geothermal systems are extremely safe and are as reliable as the electric grid that feeds them. Potential exists for ecological impact (e.g. from drilling, or from temperature changes within the system), which could be mitigated but would need to be monitored. Implementation of a utility-ownership geothermal deployment would require a modification of the utility franchise and the utility regulatory construct to allow for investment in geothermal systems. If that is achieved, consistent marketing efforts, as well as efficient installation processes and customer service capabilities, will be needed to scale.

District Heating: While a shared loop system can serve a small collection of facilities, a district energy network allows utilization of one common system to serve a broader area/ district.

One potential example relevant to Aquidneck Island given its location is a district energy system that would extract heat energy from seawater using large, electric-powered heat pumps, transferring that heat into water that would then be piped to homes and businesses in the area, providing hot water for heating. This system draws water from an engineered depth below the surface where it is less affected by winter air temperatures. The loop that distributes water would feature supply and return lines, with each customer being billed based on the BTUs that they extract from the loop. These loops would most likely be used with hydronic heating systems, but it is possible that they could be connected to heat pumps within the premises served as well.

These systems are often designed for heating only. In this design, the seawater is returned to the ocean at a colder temperature, due to the extraction of heat energy, so this impact would need to be evaluated. It may be possible to design a system that could provide cooling as well, but that would be more complicated and expensive. There would be significant upfront costs to install a district-wide system.

For reference, a similar system exists in Drammen, Norway.

Summary

The table below summarizes the assessment of the option to utilize heat electrification via air-source heat pumps as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 15: Summary of Air-Source Heat Pump Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Incremental electrification of customers who currently rely on gas heating systems (particularly those whose systems are nearing the ends of their useful lives), and heat electrification to displace the use of delivered fuels by customers who currently rely on oil and propane for heating but might otherwise connect to the gas system.
Size	2,000 to 10,500 Dth/day	Size of resource depends on solution. This requires electrification of 33% to 100% annually of customers considering replacing current HVAC with gas heating
Timeframe	---	The ramp up to a steady state of electrification depends on the solution: 3 years if conditions mandate rapid electrification, 6 years if National Grid guides the timing.
Safety & Reliability		
Safety	---	Only licensed contractors will be able to participate in the program and will have appropriate training programs for the electrification efforts
Reliability	◔	Design day savings will be certain once implemented as electrification measures are passive and have a >15-year measure life; however, National Grid's ability to aggressively scale the programs to the level and size required will pose a significant challenge. Also, if customers retain natural gas service for non-heating uses (e.g., cooking, water heating) or as a back-up heating source, design day savings could be less than anticipated. Reliability could improve over time as programs mature. There is sufficient winter and summer capacity to accommodate heat electrification in the near term for the no-infrastructure scenario. However, individual feeders, feeder sections or secondaries would likely experience

		loading that produces system thermal and voltage performance concerns. As the amount of heat electrification grows, analyzing and addressing such concerns would require potentially significant incremental investment on the electric distribution system.
Project Implementation & Cost		
Cost	○	The cost will range from $25 million to $136 million depending on the solution. It includes installation cost as well as upfront incentives to offset the operating cost difference between electricity and natural gas. In the high cost case, the necessary incentive programs to achieve the required incremental electrification ramp and scale is more expensive than alternative options.
Requirements for Implementation	◑	There are some contractors in Rhode Island who have experience with heat pump installation; the ecosystem of licensed contractors and vendors and training support would need to significantly increase to meet the program requirements
Permitting, Policy and Regulatory Requirements	◔	Requires alignment of state and local policies and regulatory outcomes across multiple areas; including regulatory pathways to support Company provision of incentives.
Environmental & Community Impact		
Environmental Impact	◕	Could lead to benefits in air quality.
Community Impact / Attitudes	◑	The communities have been generally supportive of clean energy initiatives but, given the limited experience with electrification of any type thus far, community attitudes about replacement of existing heating systems are unknown. The is some evidence of customers' willingness to replace current heating systems. Beyond the greenhouse gas reduction benefits, some customers are pleased to be done with scheduling oil deliveries and having an oil tank on their property. However, those physical benefits are not present in gas-to-electric conversions. Regarding oil-to-electric heat conversion, should that be part of the initiative, since there is an ongoing trend of customers converting from oil heat to natural gas, there may be local support for offering alternatives to oil heat. However, whether the community would be supportive of conversions away from natural gas to electric heat on this scale is unknown.

8.10. Local Supply of Renewable Natural Gas

Overview

Renewable Natural Gas (RNG) typically refers to bio-methane, methane that is produced from the breakdown of organic material and that has a lower lifecycle carbon intensity than geologic natural gas. Typical sources of RNG involve wastewater treatment plants, capped landfills, agricultural facilities (e.g. dairy farms), or biomass facilities (e.g. facilities that produce wood waste). Due to the fact that the primary constituent of RNG is also methane, it is compatible with the pipe materials and end-use equipment for the vast majority of the gas network. RNG can have lower energy content and/or non-methane constituents in it that could impact sensitive gas-fired equipment, but this can often be managed by adjusting the feedstock or blending the RNG into a larger volume of natural gas.

As a note, this option considers the specific limitations of supplying RNG to Aquidneck Island, focusing on the potential for on-island supply. These limitations likely would not apply in many other areas throughout the state. Given local limitations, an RNG solution was not modeled as part of the long-term solution for Aquidneck Island's gas capacity constraint and vulnerability needs, despite the potential for RNG to play an important role for broader gas network decarbonization. However, there may be potential for RNG to play a minor role in meeting the gas capacity needs for Aquidneck Island.

Size

Given the limited real estate on Aquidneck Island, the relatively small population, and the limited amount of agricultural feedstock, the total RNG potential is also limited. National Grid has estimated that the total amount of output is less than 100 Dth/day. This would primarily be from the wastewater treatment plant on Aquidneck Island.

It is possible that the level of RNG production could be increased if additional material (e.g. manure or agricultural waste) was trucked onto the island. Alternatively, food waste could be collected, and a system could be installed at a transfer station. Due to the cost of RNG systems, described below, it often makes sense to aggregate feedstocks to a larger central facility rather than having multiple systems that must be managed and interconnected into the gas system.

Cost

The primary technology that would viable on Aquidneck Island would be anerobic digestion. This technology involves creating an environment devoid of oxygen and introducing bacteria that will breakdown organic material. The output of this is bio-gas, which is roughly 60-70% methane with the remainder being made up primarily of $CO2$. This gas needs to be upgraded to pipeline quality, at which point it earns the moniker bio-methane.

The anerobic digestion system typically costs $1-3 million based on the specific size. This needs to be paired with a gas upgrade facility that often costs another $2-3 million. In addition, heat is needed to ensure that the system remains at an optimal processing temperature so there are operating costs for the system, typically in the form of purchased gas. Finally, there is residual organic material once the decomposition is complete, which must be removed from the system. Depending on the feedstock, this material can have useful properties (e.g. high phosphorous content for agricultural use, potential use for cattle bedding) so it might be a source of revenue, but it does require management.

Safety

RNG systems are very safe. The methane is quickly extracted from the digester and, since it is in an anerobic environment, ignition is generally not possible. The feedstocks for these systems are organic materials, which do not present any particular risks. If there is trucking of the feedstock, it is important to establish best practices relating to safety during loading, unloading, and transport.

Reliability

RNG production systems are very reliable, producing a constant volume of RNG every day as long as the feedstock flow is not interrupted. In the event that there is a disruption, the digester will continue to produce RNG for some time afterwards, which provides some insurance in the event of trucks not being able to deliver feedstock.

Requirements for Implementation

The primary requirement for implementation, other than cost, is identifying a feedstock and a site for the digester. These systems can be quite large so the plot of land for installation would also need to be large (>100' square) and would need to be close to the feedstock.

Permitting, Policy, and Regulatory Requirements

Rhode Island already has some systems in place that produce bio-gas, such as at the Central Landfill in Johnston. This means that there is a precedent for the permitting for digester systems. Each project may differ and require modification to the permitting, but it should be easier to replicate rather than starting from zero. Given the limited feedstock on Aquidneck Island, one facility is likely to provide sufficient capacity to maximize RNG production so the existing permitting process may be sufficient.

Utilities, including National Grid, have generally not been allowed to invest in projects that produce supply, whether gaseous or electrical. A regulatory change would be required to allow National Grid to invest in a facility that produces RNG. Additionally, RNG currently has an opportunity to generate additional revenue based on the Renewable Fuel Standard (RFS) 2.0, which creates obligations for fuel producers in the transportation sector. It is possible to sell the environmental attribute of the fuel in a process similar to trading renewable energy credits (RECs). Doing so could help to offset the capital cost of the system but there would need to be an established process for this attribute trading, a function that currently falls outside the utility market role.

Environmental Impact

These systems are closed, since they are designed to capture the gases that are produced, so there would not be any emissions from the digester itself. There may be impacts from the feedstock, either from the feedstock itself (e.g. odors) or from the transporting of the feedstock (e.g. increased truck traffic).

Community Impact / Attitudes

National Grid has not completed any survey of the residents of Aquidneck Island to assess their attitudes about RNG or the presence of a digester in their community. Assuming there would not be a large volume of trucked feedstock, the community impact of the digester would be small once construction had been completed and the construction process would not be particularly invasive.

Summary

The table below summarizes the assessment of the option to utilize renewable natural gas as a means of meeting the capacity and contingency need on Aquidneck Island.

Table 16: Summary of Renewable Natural Gas Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description

Overview	---	Developing RNG production facilities (anaerobic digesters) at a wastewater treatment plant, and transfer stations to manage waste and produce biomethane.
Size	<100 Dth/day	Organic feedstock on Aquidneck is small so the total output potential is limited. There may be opportunities to increase the transfer station (food waste) potential.
Timeframe	---	These systems can take several years to install but it may be easier to do so given that they are existing facilities. Timeframe would depend on the permitting process and community perspective.
Safety & Reliability		
Safety	---	Anaerobic digestion systems are generally passive and safe.
Reliability	◕	Anaerobic digestion systems are quite reliable, and the feedstock is unlikely to be disrupted.
Project Implementation & Cost		
Cost	◔	Since these systems produce baseload output (i.e. output is the same every day), the cost per design day Dth is high and may be less appealing than other alternatives.
Requirements for Implementation	◑	These systems are not new but they tend to be somewhat custom so there are risks in terms of delivery.
Permitting, Policy and Regulatory Requirements	◑	National Grid doesn't have the regulatory authority to invest in these types of systems because they are supply projects. A 3rd-party developer or a regulatory change would be required. Permitting risk is unknown.
Environmental & Community Impact		
Environmental Impact	◑	Local emissions should be captured in closed system, though other impacts would need to be studied.
Community Impact / Attitudes	◑	This is unlikely to have a strong impact on the community given that this is a modification of systems at existing facilities.

8.11. Gas Decarbonization Through Hydrogen Blending

Overview

The adoption of green hydrogen as an energy source is a fast-growing development in the energy industry worldwide. Australia, Japan, Korea, and Europe have developed energy policies to utilize hydrogen for power generation, transportation, heat, and difficult-to-decarbonize industrial sectors such as steel production. In the UK, National Grid is leading the discussion to include hydrogen in both the gas transmission networks and downstream local distribution.[30]

Hydrogen is a common industrial chemical used worldwide for chemical processes and to produce ammonia for agriculture. When created from natural gas through steam methane reforming it emits carbon dioxide unless carbon capture and sequestration (CCS) is used. With CCS, the resulting product is referred to as "blue" hydrogen. When created through electrolysis requiring only electricity and water with electricity sourced from renewable generation, "green" hydrogen is produced. With the Northeast's plans to pursue increasing renewables, electrolysis

[30] See, for example, https://www.nationalgrid.com/uk/stories/journey-to-net-zero/high-hopes-hydrogen.

creating hydrogen helps to balance renewables on the electric grid, effectively as an energy storage system, while creating a product that can be used for heat in a natural gas system.

Prior to pipeline gas arriving in the 1950s and 1960s, "town gas" manufactured locally from coal, coke, and petroleum products was delivered in the local gas distribution networks. This town gas often had 30-50% hydrogen content and was carried in the cast iron and steel pipes of the era. Despite this history, modern appliances in the US cannot readily use this level of hydrogen, but there remain examples where elevated hydrogen blends are common such as Hawaii Gas' system that has been serving approximately 12% hydrogen in their gas since the early 1970's. Pilots in Europe and Australia have successfully blended up to 20% hydrogen in gas networks and this is an achievable goal through expansion after a successful pilot.

This option specifically envisions a relatively small-scale hydrogen project including a commercially available electrolyzer system that converts electricity and city water into high purity hydrogen and oxygen. The system is relatively easy to install consisting of containerized equipment placed on foundations holding the electrolyzers, transformers, control systems, and a de-ionizing system to purify the water. For reliability purposes, National Grid would recommend some level of compressed hydrogen storage be kept on site to ensure daily delivery levels. This hydrogen would then be blended into National Grid's gas distribution network.

As described further in section 11.2, a hydrogen project like the one detailed below could serve as a foundational for a longer-term development of a hydrogen energy hub at a new Company facility initially primarily used for LNG. One example of an additional way that hydrogen could be deployed is to create a separate dedicated hydrogen network to serve a small group or single industrial customer. The principle difference between such a network and what is detailed below is that the former would entail a dedicated gas network designed for hydrogen and an end user with burner equipment tuned for hydrogen, such as a fuel cell or boiler. This type of project could replace duel-fuel customers or move a specific load off the gas network to help address the capacity constraint from this study. Since no specific customer has been identified, the Company has not conducted an analysis of this model for this study, other than to note that it has been proven in other parts of the US and world.

Size

The system should be considered a 365-day supply capacity solution incrementally serving the gas network load. Due to the heat content of hydrogen being 1/3rd that of natural gas, a 20% hydrogen blend would ultimately replace 6.67% of the natural gas used. Using 20% of Aquidneck Island flows in the summer to ensure we remain below the 20% threshold a system would need to be capable of delivering 1950 kg/day of hydrogen. This is the equivalent of an incremental 248 Dth/day. To maintain a 20% hydrogen blend by volume year-round, a combination of additional electrolyzers and storage would be needed to serve the peak loads discussed in this study. Approximately 15,000 kg/day would be needed on the peak days by 2035.

Cost

Cost of this solution can be evaluated against two business models. In the first instance National Grid could build, own, and operate hydrogen production systems with the costs as part of approved rates. The second model would involve the Company soliciting green hydrogen projects through a supply RFP where the cost of the commodity is included with other gas supply commodities.

Regardless of the scenario, the effective cost of the commodity based on current valuation of hydrogen projects in the northeast US would be approximately \$30/Dth. The economics of a hydrogen project depends heavily on the cost of electricity. For example, using current capital costs and $35/MWh electricity, roughly $15 of this cost is directly attributable to the cost of electricity. Electrolyzer costs are expected to decline significantly in the 2020s which will have the effect of reducing the base cost by 50% resulting in a combined cost of around $22/Dth with the electricity remaining at $35/MWh. Abundant low-cost electricity or curtailed power from variable renewables would make this solution more economic in the future. Utilizing off-peak energy or curtailed renewable energy from increased solar and offshore wind power will benefit the economics in the future while providing a bulk power grid balancing asset.

Safety

Hydrogen is used across the economy to produce ammonia for agriculture and in many chemical processes. In the US and Canada there are over 1,700 miles of high-pressure hydrogen transmission pipelines serving petroleum refineries as a key element in creating low-sulfur diesel fuels. North America is home to 60% of the world's hydrogen pipelines. Hydrogen re-fueling stations are becoming more common with numerous examples installed on the west coast and increasingly throughout New England, including one operating on Branch Avenue in Providence since 2017.

Hydrogen safety in this application should be assessed in two ways. Safety of the proposed facility and safety impacts of putting a hydrogen blend into the existing gas network.

Facility safety is well understood with a Center for Hydrogen Safety (CHS) established in 2004 under the American Society of Chemical Engineers. National Grid is a CHS member company. The National Fire Protection Association, the standard bearer for life safety codes used in the natural gas and other industries, has a standard NFPA 55 Compressed Gas and Cryogenic Fluids that demonstrates how to mitigate any hazards relating to these compressed gas use and operations.

Distribution system impacts are well understood given the years of experience of gas utilities serving hydrogen blends recently overseas and in the era pre-dating pipeline gas. These considerations can be grouped as follows:

- **Pipe Embrittlement in Steel Pipes:** At the distribution pressures and blend percentages below 20% embrittlement is not a concern. The hydrogen blend is expected to be transferred to lower pressure systems in Aquidneck Island containing polyethylene and cast-Iron systems are not known to be adversely affected by hydrogen-natural gas blends.
- **Leakage:** Hydrogen molecules are smaller than methane molecules. In a higher percentage hydrogen blend, the hydrogen molecule will tend to escape through pipe leaks before the larger methane molecule. However, at the low concentrations of hydrogen proposed, common system leaks are not expected to create a hazardous situation any greater than any other natural gas leak. Furthermore, given its molecular weight, hydrogen dissipates rapidly in the atmosphere. National Grid's leak prone pipe replacement efforts to reduce methane emissions also mitigates this concern.
- **Flame Characteristics:** Lower blend levels should not impact most home appliances; however, US appliances are not tested to 20% hydrogen blends as they are in Europe and other parts of the world. Some manufacturers, though, have announced plans to develop appliances that can switch between natural gas and hydrogen blends seamlessly.[31] These products are expected to be commercially available in the next few

[31] See, for example, https://www.worcester-bosch.co.uk/hydrogen.

years. Until then lower percentages of hydrogen are recommended as is the case in Hawaii.

- **Odorant:** This is not a concern at this blend level, as pilots and demonstrations in the UK and Europe where gas network blends achieve 20% hydrogen have not changed their odorant practices or performance.

Reliability

Hydrogen production is not a new science or process. Electrolyzer systems have been reliably used for decades. A capacity factor of 99% per OEM material is expected, producing hydrogen for 20 years. To increase reliability, a distributed project can easily add a buffer storage tank with approximately one day of supply. One of the benefits of modern Proton Exchange Membrane (PEM) electrolyzers is their ability to ramp up to full operation quickly; a reason they are often paired with renewable energy resources.

Requirements for Implementation

These installations are common in other parts of the world and would be easy to implement from a construction and operations standpoint once regulatory and permitting approvals were achieved.

Permitting, Policy, and Regulatory Requirements

The Company currently does not have the authority to invest in hydrogen production systems as a rate-based asset, so regulatory considerations would have to be made. An alternative option used in other jurisdictions is a non-pipes alternative solicitation where developers could bid in a supply of green hydrogen meeting company requirements for location and volume. On the permitting front, each project would be permitted on its own following local and state ordinances typical of any energy infrastructure project.

Environmental Impact

Construction activities are relatively minor for an electrolyzer plant given the energy density of electrolyzer systems. A small footprint, typically less than an acre depending on local zoning setbacks, would be cleared and pre-engineered containers would be placed on grade beams or shallow foundations. The remainder of the construction activities include buried and/or above ground utility connections for water, electricity and the outlet connection to the natural gas network. Local upgrades to the electrical grid may be needed as determined through a specific interconnection request with Narragansett Electric.

Community Impact / Attitudes

Minimal negative impacts are expected for local community and are limited to the visual aesthetic of an industrial facility and minor noise impacts. Both impacts can be mitigated with screening and sound insulation.

Summary

The table below summarizes the assessment of the option to utilize hydrogen blending as a means of meeting the capacity and contingency need on Aquidneck Island.

These installations are common in other parts of the world and would be easy to implement from a construction and operations standpoint once regulatory and permitting approvals were achieved.

Table 17: Summary of Hydrogen Blending Option
● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	---	Demonstration project to begin gas decarbonization efforts in line with Governor's executive order. Project can be sized and operated to maintain desired blend percentages. Electrolyzers are commercially available in multiple sizes with new projects frequently being announced worldwide with increasing capacities.
Size	250 to 1500 Dth/Day	Analysis for this example intended to meet 20% of the summer load increasing through later phases to meet 20% of winter loads.
Timeframe	---	2-3 years
Safety & Reliability		
Safety	---	Company has core competency in operating energy systems safely. The facility itself can meet all safety codes. Blending in the gas network will be managed through normal distribution integrity management practices used to safely operate the gas network.
Reliability	●	Project will be designed for reliable service with small amount of storage available. OEM literature claims up to 99% operational availability. O&M performed by OEM until National Grid workforce capabilities are developed.
Project Implementation & Cost		
Cost	\$2.7M/Year in supplied energy cost (for 250 Dth/day)	Today's costs at ~\$30/Dth with decreasing costs as manufacturing gains are achieved. Half of the delivered cost is due to electricity prices, use of future curtailed renewables or off-peak electric rates will reduce costs. Value shown for 250 Dth/day example.
Requirements for Implementation	◕	Well-established production technology that can be domestically sourced. Will need to work with Gas Asset Management engineers to model and vet system capabilities to ensure blend can safety be received. Similar process as required for blending RNG. Commercially available equipment by reputable suppliers. Regulatory acceptance or a business model to implement is the principle risk.
Permitting, Policy and Regulatory Requirements	◕	No different than any other energy facility. Similar to a battery system or fuel cell. Permitting is expected to include municipal building permit, fire department approvals and potential for conservation commission, SPDES and/or DEM 401 WQC. PUC approval for rate-based asset.
Environmental & Community Impact		

Environmental Impact	●	Minimal construction impact. Visual and noise impacts of electrolyzer system easily mitigated during siting process. Only waste product is oxygen released to atmosphere.
Community Impact / Attitudes	◕	System does not pollute or create undue burden on community. At low blends, impacts on customer appliances are minimized. Need to educate stakeholders as there are some misconceptions around hydrogen safety. Opportunity for Rhode Island to take a leadership role in heat decarbonization without requiring customers to change heating systems.

8.12. Other Options Considered and Ruled Out

In addition, the Company considered other options for inclusion as potential solutions but ruled them out due to feasibility or cost concerns, or because they would not meaningfully address the capacity constraint or capacity vulnerability needs on Aquidneck Island. These options considered and ruled out include the following:

- **Existing LNG Facility at the Naval Station Newport:** National Grid had limited LNG operations at the Naval Station Newport until 2010, when the company procured additional pipeline capacity from Algonquin. From 2006-2010, the site was typically operated once per year. Three issues make the existing Navy facility infeasible as a solution:
  - The current lease expires in 2026. The Navy has informed National Grid that it does not intend to renew it, as it plans to expand the use of this waterfront property for additional piers and ship mooring.
  - The current lease only allows operation of the Naval Station LNG facility for peak shaving 8-10 times per year, with limited trucking capacity (5 truck deliveries per day) compared to other sites such as Old Mill Lane. In 2019, National Grid engaged the Navy in discussions to modify the lease to allow for expanded use, but the Navy denied the request.
  - While unlikely, in a national security event the Naval Station could be secured for any external visits.
- **Portable CNG:** The Company issued an RFP and received proposals for both CNG and LNG when it developed the Old Mill Lane portable solution and determined that portable LNG was a better solution.
- **Accelerated Leak Reduction:** National Grid prioritizes distribution main leak fixes based on safety concerns, as undertaking the excavation needed to address leaks can disrupt traffic patterns and significantly inconvenience residents and businesses. Implementing a more aggressive leak reduction plan would have only marginal impacts on gas capacity, while posing significant cost and inconvenience to customers on Aquidneck Island.
- **Methanation:** A nascent technology that would combine hydrogen production with a CO_2 source to make synthetic methane, which overcomes the blending limits for hydrogen described above, this would require not only the installation of electrolysis equipment for hydrogen production but also a local source of waste CO_2. While “green” methanation technologies might contribute in the long-term to decarbonizing the heating

sector, they do not offer meaningful short-term capacity on Aquidneck Island. National Grid will continue to monitor advancement of this technology as it matures.
- **Solar Hot Water Heating:** Low solar irradiance during the winter, combined with cold atmospheric temperatures during hours of peak gas demand, make solar hot water heaters an impractical solution for addressing peak gas capacity.
- **Electric Induction Cooking:** Cooking has minimal contribution on peak gas demand compared to space heating.

9. Approaches to Meet Identified Needs

9.1. Developing Approaches to Meet Identified Needs on Aquidneck Island

Creating a comprehensive solution requires looking at how the options described above can address the capacity constraint and capacity vulnerability needs on Aquidneck Island singly or in combination. Not all options are large/scalable enough to individually solve the issue. And, the timing of when an option can be implemented may also necessitate that it be combined with others in order to address the needs since those needs already exist today. In some cases, a single option may address the needs on its own. In other cases, a portfolio of options may be required to address the needs or might offer additional benefits (reliability, flexibility, decarbonization) that a single solution would not provide.

The Company grouped the potential options into four distinct approaches as defined below, where several approaches can include different variations. Moreover, there is a role for incremental demand-side measures in all of these approaches and not just the purely non-infrastructure approach.

- Implement a **non-infrastructure solution** that relies exclusively on heat electrification, gas energy efficiency, and gas demand response to reduce peak gas demand on Aquidneck Island, continuing to rely on portable LNG at Old Mill Lane until both the capacity constraint and vulnerability needs are addressed. Addressing the capacity vulnerability need means reducing overall peak gas demand on Aquidneck Island by more than 40% compared to current projected design day demand so that customer gas demand could be met even in the face of a substantial AGT capacity disruption without LNG on the island.[32] Such an aggressive level of demand reduction will require the majority of residential gas customers on Aquidneck Island to replace their existing gas heating systems with electric heat pumps. Given current up-front and operating cost differences between these technologies, this will either impose significant costs on the residents of Aquidneck Island, or require large transfers, in the form of customer incentives, from other Rhode Islanders. Incremental demands on the electric system might also eventually require incremental investments in the island's electricity distribution network, too.

- Build a **new LNG solution with the potential for innovative low-carbon gas supply**, phase out the Old Mill Lane Portable LNG operation, and pursue incremental demand-side measures to slow gas demand growth on Aquidneck Island. This approach would continue to rely on some form of LNG on Aquidneck Island, but it could vary in terms of

[32] This level of demand reduction makes the contingency value of the non-infrastructure solution comparable to the alternative LNG options at least up to a 50% reduction in available capacity on AGT.

the location and type of LNG facility. Options include a new portable LNG facility on Navy-owned property, a permanent LNG storage facility on Navy-owned property, or an LNG barge offshore of Aquidneck Island. Pairing a new LNG solution with incremental demand-side measures that slow gas demand growth would preserve the contingency capacity over time in the event of a disruption on AGT.[33] By providing a new site for Company operations on Aquidneck Island, the LNG options on Navy-owned property could potentially be a catalyst for an innovative, low-carbon hydrogen production and distribution hub.

- **Pursue an AGT project** to address the capacity constraint and vulnerability needs. At present, there is no formal project proposed by AGT, and the scope of an AGT project could range from a system reinforcement that addresses the capacity vulnerability need on Aquidneck Island to a broader G-system expansion project that would also address regional needs in Rhode Island and Massachusetts. This approach is unique among those presented insofar as it could be a broader gas infrastructure solution that addresses regional needs across multiple gas utility service territories. The variant analyzed herein assumes an AGT project of limited scope focused on resolving the capacity vulnerability for Aquidneck Island paired with incremental demand-side measures to address the capacity constraint need.

- Simply continue using the **Old Mill Lane Portable LNG setup** indefinitely as a long-term solution coupled with incremental demand-side measures to slow gas demand growth on Aquidneck Island to preserve the contingency value from the portable LNG and to limit the circumstances under which the Company would need to dispatch portable LNG. This option addresses the capacity constraint today and through the end of the gas demand forecast period in 2034/35 even before any incremental demand-side measures. It also addresses the capacity vulnerability. Demand-side measures can complement the portable LNG, slowing or offsetting projected gas demand growth and thus preserving the contingency capacity that the LNG provides now in the event of an unexpected pipeline disruption. Pairing Old Mill lane portable LNG with incremental demand-side programs also limits the degree to which the portable LNG would be needed for meeting peak demand on extremely cold days. All other approaches described above will involve some degree of reliance on Old Mill Lane Portable LNG before it can be replaced or phased out because all other options have multi-year lead times.

Each of these solutions includes the same baseline level of energy efficiency that National Grid has already been pursuing throughout Rhode Island. In addition to that, each solution also includes some amount of incremental demand-side management in the form of increased energy efficiency, demand response, and/or electrification. The levels of incremental demand side management for each solution are identified in Table 18.

[33] For this study, the Company analyzed each LNG alternative option paired with incremental gas energy efficiency and gas demand response sufficient to maintain contingency capacity in the face of projected demand growth.

Table 18: Summary of Incremental Demand-Side Programs for Each Solution Approach

Solution	EE level	DR level	Electrification level
Old Mill Lane Portable LNG	Reach ~75% of homes and ~33% of businesses by 2034/35	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	None
New LNG Solution (Portable LNG or Permanent LNG at New Navy Site, or LNG Barge)	Reach ~75% of homes and ~33% of businesses by 2034/35	Continue large commercial DR	None
AGT Project with incremental demand-side management	Reach ~65% of homes and ~33% of businesses by 2034/35	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	Electrify ~13% of forecasted gas customers by 2034/35
No Infrastructure (Phase out Trucked LNG @ OML as-soon-as-possible exclusively through incremental DSM)	Reach ~80% of homes and ~33% of businesses by 2034/35	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	Electrify ~63% of forecasted gas customers by 2034/35

Each of these approaches are reviewed in turn in the sections below. The LNG option at a Navy-owned site presents a unique opportunity for deploying a solution to today's capacity constraint and vulnerability needs on Aquidneck Island and also starting to build a future hydrogen hub for a future deeply decarbonized Rhode Island energy system. This transition to a hydrogen hub is detailed in section 11.2, as well.

9.2. Non-Infrastructure Solution

In this approach, the Company would pursue a combination of efforts to reduce gas demand on Aquidneck Island to eventually address both the capacity constraint need and the capacity vulnerability need. Until the non-infrastructure options reduce gas demand sufficiently to address the capacity constraint need, the Company would continue to rely on portable LNG at the current Old Mill Lane location.

The purpose of this approach is to eventually phase out the portable LNG at Old Mill Lane without any additional gas infrastructure or capacity. In order to address the capacity vulnerability need in a manner comparable to the LNG and AGT project options, the non-infrastructure approach must achieve net gas demand reductions sufficient that peak gas demand would be below the level of gas capacity planned for on AGT at Portsmouth such that the Company would have contingency capacity available on AGT in the event of an expected capacity disruption.

Addressing the capacity constraint exclusively with incremental demand-side resources requires a high level of investment in gas energy efficiency, gas demand response, and heat electrification. Most of the gas demand reduction would come from conversions of gas customers to electric heat pumps. Key elements of the portfolio of programs for closing the demand-capacity gap include:

- **Demand response** – **retain current pilot program participants** – current customers in the Aquidneck Island gas demand response pilot would need to be retained in an enduring demand response program
- **Demand response – new programs** – new demand response programs would be needed with offerings for different customer segments
- **Incremental energy efficiency –** gas energy efficiency efforts substantially over-and-above present state-wide efforts would need to be pursued specific to Aquidneck Island to reduce gas demand
- **Electrification** - a robust electrification incentive program would need to be implemented to drive electrification of new construction and oil conversions (to displace gas growth), and to overcome the challenging customer economics of gas-to-electric fuel switching enough to drive enough adoption among current gas customers on Aquidneck Island (to reduce existing gas demand)

This approach would require Rhode Island to make aggressive investments in additional customer and trade ally incentives to rapidly achieve the ambitious gas savings targets required to not only offset all future gas demand growth but also to reduce gas demand below its present level given the current capacity constraint need. Correspondingly, high levels of investment in program design, implementation, and marketing and customer education would have to be core features and building blocks for a non-infrastructure approach.

The timing of when trucked LNG at Old Mill Lane would no longer be needed depends on how quickly the non-infrastructure approach could deliver the required gas demand reductions.

Each element of the non-infrastructure approach requires regulatory approval and program cost recovery from the Rhode Island PUC, and there are no precedents at this point for approval of the heat electrification programs that would be required under this approach.

Implementation of the non-infrastructure options requires effectively stacking the gas demand reductions from each program in light of their interactions—e.g., a customer in a 24-hour-event, fuel-switching gas demand response program who also participates in gas energy efficiency does not provide any incremental peak gas demand reductions from the energy efficiency measures.

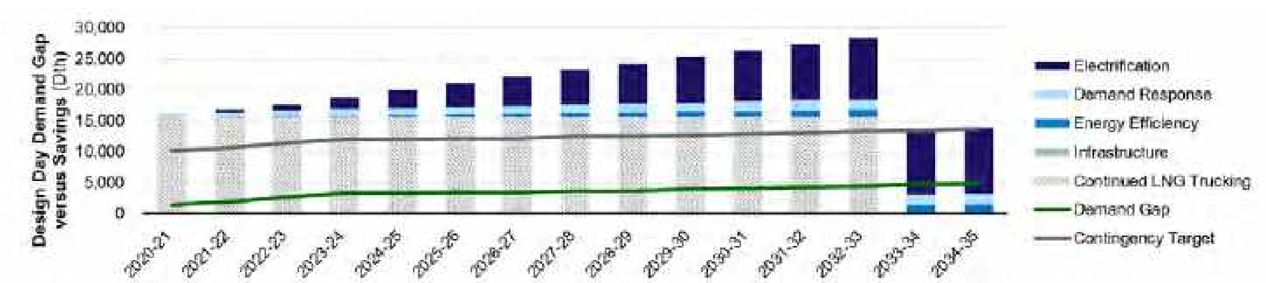
Only gas demand reductions on Aquidneck Island itself can help address the capacity constraint need. Without an AGT project implemented, gas demand reductions elsewhere in Rhode Island supplied from AGT cannot free up gas to deliver to Aquidneck Island owing to the inability to flow more gas to Aquidneck Island on AGT today under extremely cold conditions.

There are many ways to create a non-infrastructure solution, with variations not specifically modeled in this study that could include a role for local low-carbon gas supply or for a heat electrification district energy system that replaces natural gas heating for a large swath of customers.

For this study, the Company has analyzed a non-infrastructure solution based on a programmatic approach to heat electrification; however, the Company has not fully developed program design details. Rather, the Company made assumptions about program design to evaluate a non-infrastructure option. The cost profile of a non-infrastructure solution might change as actual program design details are developed. Moreover, a more codes and standards-based approach might be possible to mandate heat electrification, which would need to be implemented by Rhode Island state and local government. Such an approach would likely have a different cost profile.

Figure 11 shows the annual contributions to addressing the demand gap between the available capacity on AGT to serve Aquidneck Island and the contributions from the non-infrastructure solution. This shows an approach where demand-side measures are scaled up enough to phase-out portable LNG after 2032/2033 at which point the level of demand reduction has provided enough headroom between projected gas demand and the available gas capacity on AGT during extreme cold conditions that the resilience to capacity disruption is comparable to under the LNG solutions.

Figure 11: Annual Aquidneck Island Capacity Constraint vs. Non-Infrastructure Option (Base Demand Scenario)



Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the demand gap and contingency target. The demand gap is defined as the difference between business-as-usual forecasted demand and the Aquidneck Island pipeline capacity, and the contingency target is the level of contigency Trucked LNG at the New Navy Site would provide upon completion in 2024-25; held constant with forecasted growing demand.

An aggressive heat electrification effort on Aquidneck Island would potentially require electricity distribution network investments to support load growth. Based on National Grid's preliminary, aggregated review of summer and winter feeder capacity on Aquidneck Island, there is sufficient winter and summer capacity to accommodate heat electrification in the near term for the non-infrastructure approach. However, the location of load growth from heat electrification matters, and even with sufficient capacity in aggregate, individual feeders, feeder sections, or secondaries would likely experience loading that produces system thermal and voltage performance concerns. As the amount of heat electrification grows, addressing such concerns would require potentially significant incremental investment on the electric distribution system. If a non-infrastructure approach is pursued, National Grid's will model increasing electric demand from heat electrification to understand the long-term electricity network impacts.

9.3. New LNG Solution

Under this approach, a new LNG solution to replace the portable LNG at Old Mill Lane is pursued as the primary means of addressing the capacity constraint and vulnerability needs.

This approach has multiple variations based on the type of LNG option (portable LNG, permanent LNG storage, or LNG barge).

One route under this approach is to pursue an LNG barge as a solution. This option would address the capacity constraint and vulnerability needs and replace the need for portable LNG at Old Mill Lane.

The other route is to deploy LNG at a new site. The Company has identified parcels owned by the Navy on Aquidneck Island that are expected to be available for this purpose as the best locations for a new LNG facility. The new LNG solution at one of the Navy-owned sites could take one of the following forms:

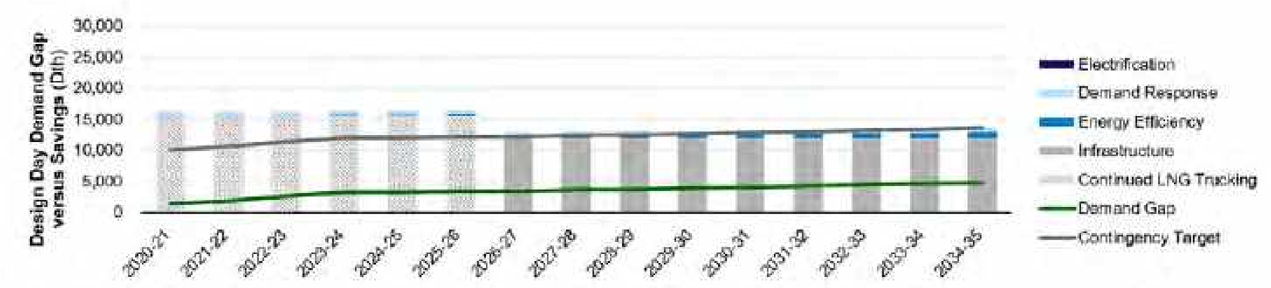
- A portable LNG solution on an indefinite basis – this option would create the infrastructure needed to support portable LNG at the new Navy site and rely on that portable LNG solution indefinitely in lieu of the portable LNG at Old Mill Lane
- A portable LNG solution on an interim basis to be replaced by a permanent LNG storage solution - this approach would prioritize phasing out the portable LNG at Old Mill Lane with a new portable LNG solution at the Navy site that would operate until it could be replaced by a permanent LNG storage solution at the same location
- A permanent LNG storage solution from the start - this option would require a longer reliance on portable LNG at Old Mill Lane since that portable LNG would be required until a permanent LNG storage facility could be constructed and placed into service, but it would avoid the cost of standing up a new portable LNG facility at the Navy site that would only be used for a short time

Securing the new Navy site and building out the gas distribution infrastructure to connect it with the broader gas network on Aquidneck Island creates an opportunity to deploy local low-carbon gas supply, which might be more difficult to site elsewhere on the island. Specifically, going down the route of building out a new LNG solution (portable LNG or permanent LNG) at a Navy-owned site could be paired with initial hydrogen production and blending that could scale to become a hydrogen production, storage, and distribution hub (described more in section 11.2 below).

Each of the new LNG solution options could be paired with incremental demand-side measures (i.e., gas energy efficiency and gas demand response) that would limit net gas demand growth over time so that that the contingency capacity provided initially by a new LNG solution could be preserved rather than eroded by demand growth. Figure 12 shows how, in the case of the permanent LNG at a Navy-owned site, the new LNG solution would eventually replace portable LNG at Old Mill Lane and how incremental demand-side measures would complement the infrastructure component of the solution.

Absent incremental demand-side programs on Aquidneck Island, projected growth in customer demand would mean that over time the likelihood of needing to dispatch LNG to meet peak demand on a very cold day would increase. Per the Company's baseline long-term demand forecast, by 2034/25, customer demand on days that are 14 degrees Fahrenheit or colder might exceed the available AGT capacity during at least the peak hour of the day. In a "normal year," the Company expects only one such day, and in a design year, the Company projects only 8 such days. The level of incremental demand-side measures paired with the new LNG solutions for this study, would slightly reduce the projected likelihood of needing to dispatch LNG to meet peak demand needs, with the number of days in a design year in 2034/35 when LNG would be needed limited to 7.

Figure 12: Annual Aquidneck Island Capacity Constraint vs. Permanent LNG at Navy-Owned Site Paired with Incremental Demand-Side Measures (Base Demand Scenario)



Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the demand gap and contingency target. The demand gap is defined as the difference between business-as-usual forecasted demand and the Aquidneck Island pipeline capacity, and the contingency target is the level of contigency Trucked LNG at the New Navy Site would provide upon completion in 2024-25, held constant with forecasted growing demand.

9.4. AGT Project

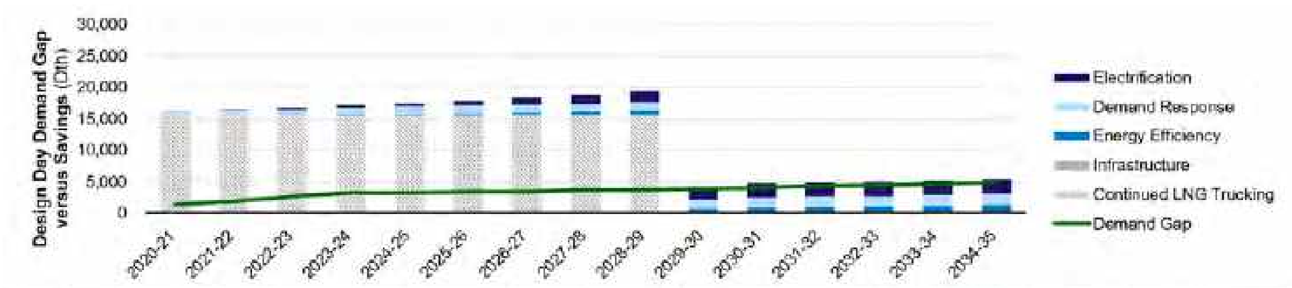
The details of an AGT project are yet to be determined and could range from a more narrowly targeted system reinforcement project to address needs on Aquidneck Island to a broader system expansion project that would address regional needs of multiple gas utilities. The scope of the project would determine the timing, the cost, the number of gas utilities involved as customers, and the degree to which an AGT project addresses both the capacity vulnerability and capacity constraint needs on Aquidneck Island.

At a minimum, an AGT reinforcement project would address the capacity vulnerability need on Aquidneck Island. There are three routes to take to solve the long-term capacity constraint under this approach:

- If there is a broader AGT project, which would likely be done together with other gas utilities also served by AGT in both Rhode Island and Massachusetts, such a project could provide additional gas capacity on AGT to Aquidneck Island to address the long-term capacity constraint.
- The Company could reduce demand on Aquidneck Island and elsewhere in select parts of Rhode Island to balance gas demand and capacity across multiple take stations along the G-lateral. Only with an AGT reinforcement project in-service would demand reductions in other parts of Rhode Island upstream from Portsmouth on AGT help make more gas capacity available to Aquidneck Island.
- Provide additional supply capacity from portable LNG either on Aquidneck Island (at Old Mill Lane) or at another location in select parts of Rhode Island on the AGT G-lateral to meet the capacity constraint. However, with the AGT pipeline reinforcement, portable LNG would only be a solution needed to meet peak demand and not mobilized under relatively mild winter weather as today for the purpose of addressing the capacity vulnerability need.

Figure 13 shows how an AGT Project narrowly scoped on reinforcements to address the capacity vulnerability could be paired with incremental demand-side measures to address the Aquidneck Island capacity constraint. In this case, it takes several years after the AGT project comes online before demand-side measures can scale up sufficiently to fully close the demand gap and allow for the portable LNG solution to be phased out. For the purposes of this study, the Company modeled only incremental demand-side measures on Aquidneck Island paired with an AGT project. However, if this option were pursued, demand reductions in other parts of Rhode Island could also help resolve the capacity constraint so the necessary demand reductions might be achieved more quickly and/or at lower cost than presented in Figure 13.

Figure 13: Annual Aquidneck Island Capacity Constraint vs. AGT Project Paired with Incremental Demand-Side Measures (Base Demand Scenario)



Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the demand gap and contingency target. The demand gap is defined as the difference between business-as-usual forecasted demand and the Aquidneck Island pipeline capacity, and the contingency target is the level of contingency Trucked LNG at the New Navy Site would provide upon completion in 2024-25, held constant with forecasted growing demand.

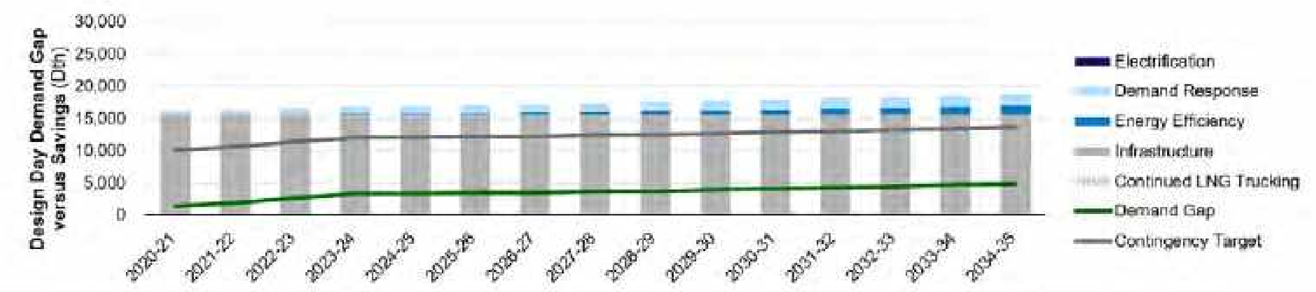
9.5. Continue to Use Old Mill Lane Portable LNG

In this approach, the Company would continue to rely on portable LNG at the current Old Mill Lane location through at least winter 2034/35 to address the capacity constraint and vulnerability needs. While the Company would mobilize portable LNG operations each winter under this approach, absent an unexpected disruption to the AGT pipeline capacity available at Portsmouth, the Company would only expect to actually vaporize gas and run additional trucks to the site to bring in more LNG supply in the event of extreme cold weather, colder than what is seen in an average winter.

The portable LNG at Old Mill Lane could be complemented by incremental demand-side measures to slow the rate of growth of gas demand on Aquidneck Island, which would help to maintain the level of resilience that the portable LNG offers in the face of AGT capacity disruptions and to further limit the frequency with which extreme cold weather would require dispatching LNG to meet peak customer gas demand on the island. Figure 14 illustrates how the continued use of portable LNG at Old Mill Lane would meet the capacity constraint through 2034/35 (and beyond) and how pairing it with incremental demand-side measures would help maintain the level of contingency capacity provided by limiting demand growth over time.

Absent incremental demand-side programs on Aquidneck Island, projected growth in customer demand would mean that over time the likelihood of needing to dispatch LNG to meet peak demand on a very cold day would increase. Per the Company's baseline long-term demand forecast, by 2034/25, customer demand on days that are 14 degrees Fahrenheit or colder might exceed the available AGT capacity during at least the peak hour of the day. In a "normal year," the Company expects only one such day, and in a design year, the Company projects only 8 such days. The level of incremental demand-side measures paired with the Old Mill Lane LNG option for this study, would somewhat reduce the projected likelihood of needing to dispatch LNG to meet peak demand needs, with the number of days in a design year in 2034/35 when LNG would be needed limited to 6.

Figure 14: Annual Aquidneck Island Capacity Constraint vs. Old Mill Lane Portable LNG Paired with Incremental Demand-Side Measures (Base Demand Scenario)



Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the demand gap and contingency target. The demand gap is defined as the difference between business-as-usual forecasted demand and the Aquidneck Island pipeline capacity, and the contingency target is the level of contigency Trucked LNG at the New Navy Site would provide upon completion in 2024-25, held constant with forecasted growing demand.

10. Evaluation of Approaches to Meet Needs

10.1. Multi-Criteria Evaluation of Approaches

The Company evaluated each of the approaches (and variants among them) against a range of criteria as summarized below. Public safety is paramount in everything the Company does, and National Grid must be confident that whichever option is pursued protects the safety of the public and the Company's employees. The Company did not present any options in this study that are not safe for the public and its employees. Key findings from the evaluation (cost is addressed separately below) include:

- **Timing** – The approaches differ in terms of how long they take to replace the portable LNG at Old Mill Lane if ever, with a purely non-infrastructure approach taking by far the longest at an estimated 13 more winters. Several of the new LNG solutions can potentially phase out Old Mill Lane portable LNG after only three more winters.
- **Cost** – The approaches vary substantially in cost. Cost is treated separately below. Given the early stage and lack of detail on any potential AGT pipeline project, there is no cost information available for this option; however, this option would address the need on Aquidneck Island among other regional needs, so the cost would not be directly comparable to options that solely meet the needs on Aquidneck Island.
- **Reliability** – All of the options can provide the reliability needed for Aquidneck Island. Every option can face challenges to reliability, such as upstream disruptions on gas pipelines, the operational complexity of LNG options, and the need for effective program design and successful track record of gas demand response. The gas utility industry has long used portable LNG as a stop-gap solution. National Grid's experience in portable pipeline supply operations and recent increased usage of portable LNG, as well as portable compressed natural gas (CNG), across its service territories to meet peak customer demand has led the Company to conduct rigorous process safety assessments at each site as well as of transportation activities and implement risk mitigation measures through design improvements and operating plans. This analysis coupled with years of operating experience in portable LNG and CNG operations has provided confidence in the overall reliability of these options.
- **Community Impacts** – The Old Mill Lane portable LNG option rates lowest because of existing concerns from nearby residents. Because none of the other options involve

operations within as close proximity to residential neighborhoods, other options may rate more highly on community impacts. However, any of the other infrastructure options could engender similar or even greater community concern from different community members. The non-infrastructure option would require unprecedented levels of effort by community members to participate in adopting energy efficiency measures like home weatherization and home heating system replacements; moreover, the non-infrastructure option would require continued reliance on Old Mill Lane portable LNG for an estimated 13 more winters, with associated continued community impacts.

- **Local Environmental Impacts –** The continued use of Old Mill Lane portable LNG has no construction required since it is a temporary facility demobilized at the end of each winter. All of the other infrastructure options would have environmental impacts from construction and operation (e.g., noise, air emissions from trucking, water impacts) that would need to be mitigated per applicable rules and regulations. An alternative LNG site on Navy-owned property is a potentially contaminated site whose environmental remediation requirements are not yet known. Decarbonization, specifically, as an environmental concern is considered separately below.
- **Implementation and Feasibility** – The requirements for implementation and the feasibility or likelihood of success differentiate the approaches. Long-term reliance on Old Mill Lane portable LNG faces legal uncertainty that would need to be resolved favorably. Gas pipeline projects have faced opposition that has stymied some projects recently in the Northeast. The non-infrastructure approach relies on a relative percentage demand-side reduction that far exceeds anything achieved historically in Rhode Island or elsewhere and assumes demand-side programs that have no current regulatory approval or funding.

Table 19: Multi-Criteria Evaluation of Long-Term Solution Approaches

Approach	Size (Dth/day)*	Last Winter Old Mill Lane LNG Needed	Cost	Reliability	Community	Local Environmental Impacts	Implementation / Feasibility
Continue Old Mill Lane Portable LNG							
Old Mill Lane Portable LNG	15,600+ (+3,000 DSM)	n/a	◕	◑	◔	◕	◑
New LNG Solution							
LNG Barge	12,000-14,000	2023/24	◑	◑	◑	◑	◑
Portable LNG at Navy Site	12,000-14,000	2023/24	◔	◑	◑	◑	◕
Portable LNG at Navy Site transition to Permanent LNG Facility**	12,000-14,000	2023/24	◔	◕	◑	◑	◕
Permanent LNG Facility at Navy Site	12,000-14,000	2025/26	◔	◕	◑	◑	◕
AGT Pipeline Project							
AGT Project	N/A (~5,000 DSM)	2028/29	◔	●	◑	◑	◔
Non-Infrastructure							
Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification***	~14,000	2032/2033	◔	◑	◑	●	◔

* Ranges shown for the capacity provided by LNG options reflect potential impact of incremental DSM paired with LNG options. AGT project as presented would include incremental DSM to address capacity constraint need.
**In this option, the Old Mill Lane portable LNG is initially replaced by portable LNG at a new Navy site which is in turn replaced by permanent LNG storage at the new Navy site. This approach replaces Old Mill Lane portable LNG an estimated two years sooner than simply transitioning to a permanent LNG storage solution, but that comes at a higher cost from deploying the interim portable LNG at the new Navy site.
*** Reliability of non-infrastructure options could improve over time as gas demand response programs mature and have more of a track record of reliably delivering during peak demand conditions. The community rating shown for the non-infrastructure approach reflects the demand-side programs themselves; however, this approach would necessitate continued reliance on Old Mill Lane portable LNG for more than another decade, with the accompanying community impacts from that prolonged reliance on that option.

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

In evaluating the different long-term solutions for Aquidneck Island, it is important to look at what it would take to deliver each solution and what the implications would be for customers.

Table 20: Summary of Implementation Considerations and Implications for Customers of Long-Term Solution Approaches

Approach	Implementation (Policy, Regulatory, Permitting, etc.)	Implications for Customers
Continue Old Mill Lane Portable LNG		
Old Mill Lane Portable LNG	Resolution of legal uncertainty re: proceeding before Energy Facilities Siting Board (EFSB) over its jurisdiction over temporary portable LNG. Will require town council / local permit approval.	Potential for continued concern from some nearby residents. Indefinite use of portable LNG to meet peak demand.

	Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	
New LNG Solution		
LNG Barge	U.S. Coast Guard permitting process required for barge as well as local construction permits. Timely permitting process depends on local stakeholder support. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Old Mill Lane portable LNG likely required for four more winters before this option is ready. Once an LNG barge solution is implemented, there is no need for LNG trucks on Aquidneck Island.
Portable LNG at Navy Site	Successful negotiation of lease with Navy for new site. Environmental site remediation (if applicable). Gas network mains extension to connect to new site. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Old Mill Lane portable LNG likely required for four more winters before this option is ready. Indefinite use of portable LNG to meet peak demand. Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.
Permanent LNG Facility at Navy Site	EFSB approval for permanent facility Successful negotiation of lease with Navy for new site. Environmental site remediation (if applicable). Gas network mains extension to connect to new site. Paired demand-side measures require regulatory approval, incremental funding, and program design and implementation.	Old Mill Lane portable LNG likely required for six more winters before this option is ready. LNG trucking would be required for LNG storage refilling. Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.
Portable LNG at Navy Site transition to Permanent LNG Facility	Same as two Navy site LNG options above	Old Mill Lane portable LNG likely required for four more winters before this option is ready. LNG trucking would be required for LNG storage refilling. Customers would bear the setup costs of the temporary portable LNG that would only be used before the permanent LNG storage goes into service.

<table>
<tr><td></td><td></td><td>Long-term potential for hydrogen hub that could supply future customer demand for low-carbon fuel.</td></tr>
<tr><td colspan="3">AGT Pipeline Project</td></tr>
<tr><td>AGT Project</td><td>Proposal of specific project by AGT.

Potential need for participation agreements with additional Massachusetts gas utilities and formal regulatory approval by Massachusetts Department of Public Utilities for a regional project or a reinforcement project that benefits customers in both Rhode Island and Massachusetts.

All necessary federal and state approvals and permits obtained by AGT.</td><td>The expected in-service date of an AGT project is unknown and may depend on the scope, but the Company expects an AGT project to be in service no earlier than 2025/26, but the Company projects that it would take an additional three years for incremental demand reductions to scale sufficiently to address the capacity constraint and allow for portable LNG at Old Mill Lane to be phased out.</td></tr>
<tr><td colspan="3">Non-Infrastructure</td></tr>
<tr><td>Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification</td><td>Regulatory approval for incremental funding and new programs, including approval for heat electrification program(s) with no precedent in Rhode Island.

Demand-side management program design and implementation.

Workforce development and installer capacity build up specific to Aquidneck Island.

Substantial heat electrification on Aquidneck Island could eventually require incremental investments in National Grid’s electricity distribution network to accommodate winter load growth. Understanding the needed investment would require further study.

Potential for a more codes and standards-based approach to driving electrification, which would require implementation by state and local government.</td><td>Even with aggressive ramp up of demand-side programs, portable LNG likely needed for an estimated 13 more winters before it can be fully replaced by demand-side measures.

Customers will have to adopt energy efficiency measures and heat electrification at unprecedented rates. These demand-side measures, even when heavily subsidized, require substantial customer effort and engagement.

A non-infrastructure solution would provide qualitatively different resilience in the face of an AGT disruptions (e.g., reductions in gas demand cannot counteract the need for 100% customer service interruption if 100% of AGT capacity is lost due to a disruption).

In the near term, ambitious ramp up of demand-side programs on Aquidneck island could displace resources devoted to demand-side efforts in other parts of the state which could undermine achievement of statewide gas demand reduction goals.

Incremental electricity distribution network investments, if required to accommodate load growth from heat electrification on Aquidneck Island, would increase costs (not yet quantified) for Rhode Island electricity customers.</td></tr>
</table>

10.2. Methodology and Assumptions for Evaluating Cost

This study provides cost estimates for the various options considered. Since the costs are presented in the interest of choosing from among a wide range of options, the Company has not developed the level of detail and rigor of cost analysis that would be done before implementing an option. Rather many of the costs presented are based on, for example, conceptual engineering or other preliminary stage estimates for infrastructure investments or demand-side program incentives.

Three different cost comparisons are presented:

- **Net Utility Implementation Cost** – This methodology calculates the cost to the Company to implement each option, net of any avoided gas commodity costs resulting from demand-side option generated savings. This is most closely aligned with net costs that will flow through gas customer bills during the time horizon for this report. It is presented as a net present value of net costs incurred through 2034/35, assuming 2% inflation and a 7.54% nominal discount rate.[34]
- **Net Utility Implementation Cost per Customer** – This methodology looks at the net cost of implementing each option divided by the forecasted number of gas customers in Rhode Island. No discount rate is applied to this cost. To the extent that incremental electrification reduces the relative number of gas customers in each option, this analysis assumes that remaining gas customers in Rhode Island will bear more cost per capita to implement that option.
- **Net Rhode Island Test Cost** – This methodology seeks to apply the principles of the Rhode Island Benefit Cost Test (RI Test)—approved by the PUC for use in evaluating National Grid's energy efficiency programs and developed in accordance with the Docket 4600 Benefit-Cost Framework—to assess the net cost of solutions, and it has the most impact on how the net costs of demand-side options are calculated.[35] Whereas the methodologies above focus generally on net costs that impact the Company's gas customers through the time horizon of this study (i.e., 2034/35), this methodology includes a few key differences (detailed further below). This methodology also looks at costs and benefits that would impact Rhode Island more broadly, including impacts to the electricity market and network that flow through to electricity customers and societal benefits like monetized benefits from avoided greenhouse gas emissions. This methodology also accounts for the benefits realized over the full lifetime of demand-side measures even when those extend beyond the time horizon of the study.[36] This methodology assumes the same 2% inflation and 7.54% nominal discount rate.

[34] This discount rate is based on the pre-tax weighted average cost of capital from the FY 2021 Gas Infrastructure, Safety and Reliability (ISR) Plan, RIPUC Docket No. 4996.

[35] A detailed description of the RI Test is found in the 2020 Rhode Island Test Description from Attachment 4 to the Annual Energy Efficiency Plan for 2020 Settlement of the Parties in RIPUC Docket No. 4979, available at http://www.ripuc.ri.gov/eventsactions/docket/4979page.html.

[36] To illustrate this point, an incremental gas energy efficiency effort on Aquidneck Island might implement a home weatherization project in 2034/35 to reduce peak gas demand in that year, with the full cost of the weatherization measure incurred in that year. However, this investment in a home weatherization would yield benefits from, e.g., avoided gas commodity costs, for several years beyond the timeframe of this study. The Net Rhode Island Cost methodology would capture that full stream of benefits.

The net cost estimates capture the following key cost components shown in Table 21.

Table 21: Comparison of Cost Components Included in Net Utility Implementation Cost and Net Rhode Island Cost

Net Cost Category	Definition	Included in Net Utility Implementation Cost	Included in Net Rhode Island Test Cost
Project Cost	Upfront capital cost associated with projects (e.g., equipment costs, construction and installation) are estimated and translated into annualized costs based on assumed carrying charge rates.	X	X
Annual Operating Cost	Estimated annual cost of operations for the different options, as well as the estimated annual costs to implement and execute different demand-side programs (including incentive and non-incentive costs).	X	X
Net Commodity Cost	Net cost of change to effective price and/or quantity of gas commodity used in an assumed normal weather year. The baseline assumes that excess demand in the normal year has zero associated commodity cost. If options involve different fuel costs (e.g., between pipeline gas and LNG) those costs are assumed to reflect current fuel prices plus inflation. The demand-side options generate savings, resulting in avoided gas commodity costs, as customers would be consuming less gas. These savings are valued at the avoided cost of gas commodity from the 2018 AESC.	X	X
Incremental Cost of Demand-Side Measures to Participants	Cost of technology installed as part of demand-side options that is incremental to any assumed baseline technology costs. For example, the additional cost of electric heating equipment compared to gas heating equipment for electrification. These costs are net of incentives to avoid double counting.[37]		X
Quantified Rhode	Other quantified net costs based on the Rhode Island Test. See following table.		X

[37] Whereas the net utility implementation cost includes the cost of incentives paid by the Company needed to drive incremental DSM adoption, the Rhode Island test only includes the incremental cost of technology that otherwise wouldn't have been purchased, regardless of who pays for it. If an incentive covers less than 100% of the DSM incremental cost, then the RI test will show a higher cost than the net utility cost, and vice-versa.

Island Test Categories			

The Rhode Island Test defines several cost and benefit categories for consideration beyond the cost categories included in the calculation of the net implementation cost. This test has been used to assess the cost-effectiveness of gas energy efficiency measures and potential non-infrastructure solutions to electric capacity constraints. National Grid is in the process of developing an approach to apply the principles underlying the RI Test to assess "non-pipeline alternatives" that meet gas system needs. In the meantime, the Company made simplifying assumptions to develop a cost estimate for this study based on the principles of the Rhode Island Test. Table 22 provides details on how each of the Rhode Island Test categories were treated for this study. The non-energy impacts and economic development impacts that can be quantified per the RI Test for energy efficiency measures were not included since they cannot presently be quantified for the other options. Excluding them from the net Rhode Island Cost methodology allows for a more consistent comparison across options.

Table 22: Details on Rhode Island Test Application

Rhode Island Test Category	Quantified	Monetization Method	Notes
Electric Energy	X	2018 AESC	
Electric Energy DRIPE	X	2018 AESC assuming 2020 install year [1]	
Electric Cross DRIPE	X	2018 AESC	
Electric Generation Capacity	X	2018 AESC assuming 2020 install year [1]	Assumes ISO-NE continues to be summer peaking [2]
Electric Generation Capacity DRIPE	X	2018 AESC assuming 2020 install year [1]	Assumes ISO-NE continues to be summer peaking [2]
Electric Reliability	X	2018 AESC assuming 2020 install year [1]	Assumes ISO-NE continues to be summer peaking [2]
Electric Transmission Capacity	X	2018 AESC	Assumes ISO-NE continues to be summer peaking [2]
Electric Distribution Capacity	X	2018 AESC	Assumes ISO-NE continues to be summer peaking; does not calculate Aquidneck Island specific value, and does not include added cost necessitated by electrification [2,3]
Gas Energy	X	2018 AESC	
Gas Energy DRIPE	X	2018 AESC assuming 2020 install year [1]	

Rhode Island Test Category	Quantified	Monetization Method	Notes
Gas to Electric Cross DRIPE	X	2018 AESC assuming 2020 install year [1]	
Fuel Oil Energy	X	2018 AESC	
Fuel Oil Energy DRIPE	X	2018 AESC	
Electric Non-Embedded Emissions	X	2018 AESC	
Gas Non-Embedded Emissions	X	2018 AESC	
Fuel Oil Non-Embedded Emissions	X	2018 AESC	
Non-Energy Impacts			Would be present for some EE measures but was not quantified for this particular collection of proposed measures
Economic Development Impacts			Would vary by type of project (infrastructure/ non-infrastructure) and was not quantified for this analysis
Utility Costs	X	Estimated costs, as discussed above	
Customer Costs	X	Estimated costs, as discussed above	

1. For benefits that vary by install year, values for the 2020 install year were shifted back to apply to each install year, consistent with National Grid's approach to energy efficiency BCA; this further assumes that market effects persist as modeled in the 2018 AESC.
2. The AESC did not identify benefits to reducing winter peak consumption
3. Potential increases in electric distribution capacity costs are discussed in Section 8.9

Note that for some demand-side options these categories manifested as a benefit and for others a cost. For example, energy efficiency had net electric energy benefits while electrification had net electric energy costs.

10.3. Cost Analysis of Approaches – Net Utility Implementation Cost

National Grid modeled the cumulative cost impacts of the different approaches through the time horizon for the study out to winter 2034/35. The cost analysis included the forward-looking (i.e., not sunk) costs associated with capital investments, operating expenses, fuel costs, and third-party contracts. It also included the cost of maintaining the Old Mill Lane portable LNG for any interim period during which it remains needed before the alternatives come online. Where demand-side measures include savings from avoided energy costs, those are netted out.

Figure 15 presents the cumulative net present value (NPV) of estimated costs for the different approaches through the winter of 2034/35 following the net utility implementation cost methodology described above. For this cost analysis each of the infrastructure options has been paired with complementary incremental demand-side programs.[38]

All costs are subject to uncertainty, and in some cases rely on conceptual engineering cost estimates for major capital projects. National Grid anticipates future incremental electricity distribution network investments would be required to support the level of heat electrification seen in the non-infrastructure approach, but such costs have not yet been estimated and are not included in the study's cost analysis.[39]

As Figure 15 below shows, continued reliance on Old Mill Lane portable LNG (with or without complementary incremental demand-side measures) is estimated to be the least-cost option with the LNG barge option the lowest cost option among the alternatives, followed by the new Navy site LNG options.[40] The AGT project and the non-infrastructure approaches are the most costly.

For the purposes of the study's modeling analysis, the AGT project was paired with demand reductions exclusively on Aquidneck Island, but an AGT system reinforcement would allow the capacity constraint need to be met with demand reductions upstream on AGT in certain other parts of Rhode Island, which would create the potential for a lower cost for achieving the needed demand reductions than presented in Figure 15. The cost of the AGT project will depend on the scope of the project and the degree to which multiple gas utilities participate. The costs presented herein represent a likely floor on the infrastructure cost given that the study assumes an AGT project with a scope limited to system reinforcement with cost sharing with National Grid in Massachusetts based on benefits realized on the AGT G-system in Cape Code. However, a larger AGT project with a scope that addresses broader regional needs would not be directly comparable to the other options because it would address other needs for Rhode Island gas customers and not just the needs on Aquidneck Island.

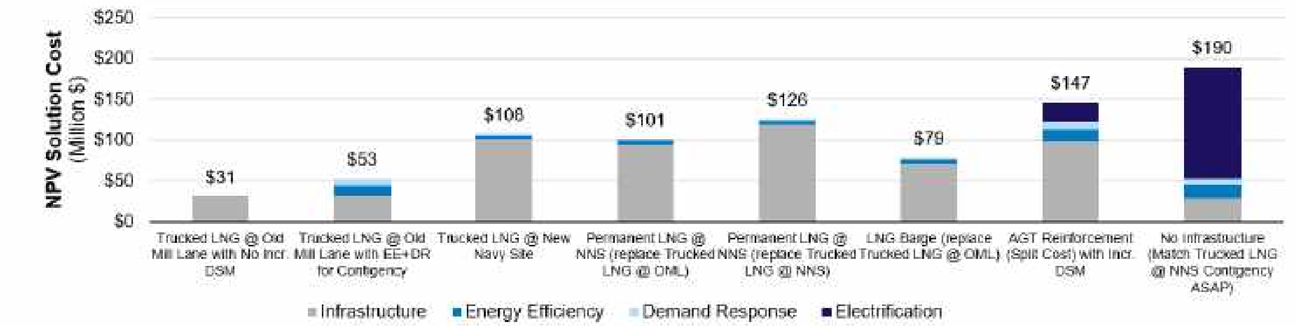
The Company also looked at the cost of the options under the high and low long-term gas demand scenarios but found no material change in the relative costs.

[38] Each of the LNG options presented as alternatives to Old Mill Lane portable LNG is paired with incremental gas energy efficiency and gas demand response on Aquidneck Island. The Company set the level of incremental demand-side programs to preserve the contingency capacity offered by the LNG option over time in the face of projected gas demand growth. The level of contingency capacity in each case is benchmarked to what the portable LNG at the new Navy site would provide when it goes into service. Even without being paired with incremental demand-side programs the portable LNG at Old Mill Lane exceeds this level of contingency capacity. The Company analyzed an option where continued reliance on portable LNG at Old Mill Lane is paired with aggressive incremental gas energy efficiency and demand response on Aquidneck Island which approximately offsets projected gas demand growth and maintains the current level of contingency capacity provided by the Old Mill Lane portable LNG.

[39] As both the electric and gas distribution utilities on Aquidneck Island, National Grid did conduct a preliminary, high-level review of the ability of the electric distribution network on Aquidneck Island to support heat electrification and found that individual sections of the electric network would likely experience load growth from heat electrification that would require incremental network investments, but identifying the expected investments and their costs would require further study beyond the scope of this study.

[40] The cost analysis finds the Permanent LNG option to be lower cost than the portable LNG at the new Navy site because the former takes longer to go in-service and thus includes two additional years of reliance on the low-cost portable LNG at Old Mill Lane.

Figure 15: Net Present Value of Net Utility Implementation Costs for Aquidneck Island Solutions through 2034/35 (Baseline Demand Scenario)



Notes: Net present value of costs up to 2034/35, using a 7.54% discount rate and 2.00% inflation rate. Infrastructure costs include fixed annual costs and net commodity costs, assuming normal year usage. Demand side resource costs include incentive costs and non-incentive program costs, net of gas commodity savings through 2034/35, monetized using the 2018 AESC. Note that any incremental electric infrastructure costs are not included. These are based on demand forecasted in a base economic scenario.

10.4. Cost Analysis of Approaches – Net Utility Implementation Cost per Customer

While the total cumulative cost analysis above provides a useful "apples-to-apples" comparison across the options in terms of total cost over time, National Grid also estimated the average cost impact on Rhode Island gas customers over time for the different approaches.

Per the standard regulatory cost recovery, the Company assumes that the cost of any solution to the Aquidneck Island needs would be recovered from all National Grid gas customers across Rhode Island (with the exception of any incremental electricity distribution network investments required to support heat electrification, which would be borne by Rhode Island electricity customers).

While a detailed bill impact analysis is beyond the scope of this study, the table below estimates for each option how the average annual cost per customer compares to the current average total costs paid by all Rhode Island gas customers for their service (both energy delivery and energy commodity)—i.e., about $1,700 per year across residential and business customers.

Table 23: Net Utility Implementation Cost per Customer through 2034/35 (Including Complementary Incremental Demand-Side Measures for Infrastructure Options)

Approach		Average 15-Year Annual Cost per Customer ($ per year)	Average 15-Year Annual Cost per Customer as % of Average Current Total Cost per Customer
Continue Old Mill Lane Portable LNG		$10	0.6%
Old Mill Lane Paired w/ Enhanced Demand-Side Measures		$18	1.0%
New LNG Solution	LNG Barge	$27	1.6%
	Portable LNG at Navy Site	$37	2.2%
	Permanent LNG Facility at Navy Site	$36	2.1%
	Portable LNG at Navy Site transition to Permanent LNG Facility	$44	2.6%
AGT Project		$51	3.0%

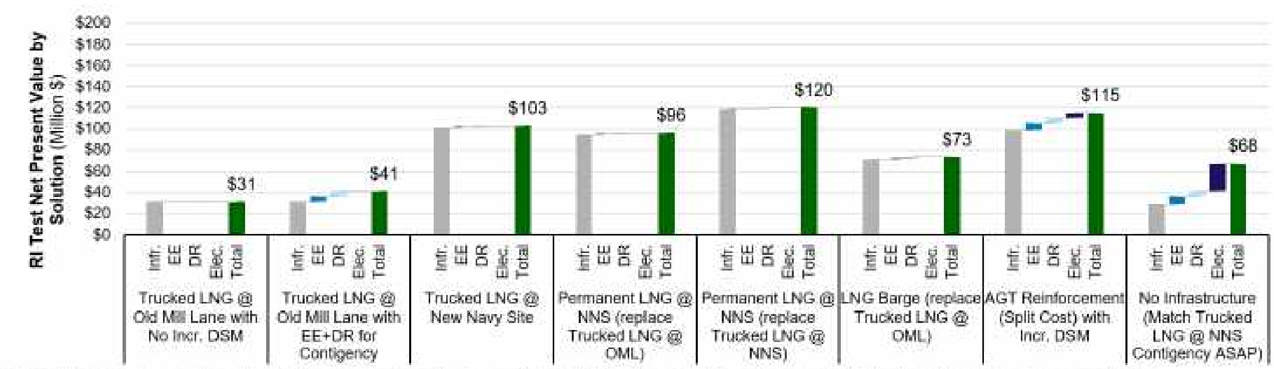
Non-Infrastructure	Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification	$63	3.7%

Notes: The table above ignores nuances in how different cost components for different options might vary in how they are recovered from certain customer types. The analysis excludes capacity-exempt customers.

10.5. Cost Analysis of Approaches – Net Rhode Island Cost

The Company also analyzed the cost of the different long-term solutions using the net Rhode Island Cost, per the methodology explained above. Figure 16 summarizes the results of this analysis. While the absolute values change relative to the net implementation cost analysis approach above, the relative ranking of the options in terms of cost remains unchanged with two important exceptions. The AGT project approach becomes comparable in cost with the LNG options at the new Navy site, and the non-infrastructure option becomes the third lowest cost option per this cost analysis methodology.

Figure 16: Net Rhode Island Cost Comparison across Solutions



Notes: Net present value based on the Rhode Island cost test, using a 7.54% discount rate and 2.00% inflation rate. Infrastructure costs include fixed annual costs assumed to incur between the install year and 2034/35, net of commodity cost savings, which are based on forecasted normal year consumption through 2034/35. Demand side resource costs include incremental technology costs and non-incentive program costs, net of benefits accumulated over the useful life of the resource. These benefits are based on the RI Test and monetized per the 2018 AESC, except non-energy benefits and macroeconomic benefits which are excluded. Avoided electric distribution capacity benefits are monetized in the same way, although high levels of electrification may instead necessitate upgrades, which may manifest as a net cost. These are based on demand forecasted in a base economic scenario.

The following discussion explains why the non-infrastructure option moves from being the costliest approach to one of the least costly options depending on the cost analysis methodology chosen. Table 24 summarizes the drivers behind the different cost results for the non-infrastructure approach (in the table, drivers with negative values reduce the total cost moving from the net utility implementation methodology to the net RI cost methodology).

Table 24: Disaggregation of Difference between Total Cost of Non-Infrastructure Approach under Net Utility Implementation Cost and Rhode Island Cost Methodologies

Driver	Delta to Net Utility Implementation Cost Through 2034/35 ($million)	Delta to Net Utility Implementation Cost Post 2034/35 ($million)	Total Delta to Net Implementation Cost ($million)
Net Energy Impacts	-$4	-$16	**-$20**
Net Emissions Impacts	-$14	-$14	**-$28**
Peak Electric Impact	-$11	-$9	**-$21**
Net Program Costs	-$53	N/A	**-$53**

Total Delta to Implementation Cost	**-$83**	**-$40**	**-$122**

As demonstrated above, key drivers for the divergence in cost estimates for the on-infrastructure approach include:

- Timeframe of evaluation – the Rhode Island Test methodology includes benefits that occur after 2035. This creates a benefit (over the Net Utility Implementation Cost) of approximately $40 million.
- Program costs – Rhode Island Test costs include incremental technology cost but does not count incentive costs. Since the non-infrastructure approach relies on incentives assumed to exceed incremental technology cost in order to enable aggressive adoption of heat pumps (i.e., to cover the increased operational costs of electrified heating versus gas), this leads to a lower cost under the Rhode Island Test methodology by approximately $53 million.
- Additional benefits considered – Other benefits (energy savings, reduced emissions, and peak electric capacity benefits) explain the remaining $29 million of difference between the two cost analysis methodologies. The Rhode Island Test methodology as applied assumes that the electric system will continue to be summer-peaking; additional infrastructure costs associated with aggressive heat electrification are not included under either methodology.

In short, the Net Utility Implementation Cost methodology considers cost impacts that will be borne by National Grid gas customers through 2034/35, while the Rhode Island Test methodology as applied in this study also considers incremental benefits over a longer time horizon and ignores transfer payments between Rhode Islanders in the form of demand-side measure incentives.

10.6. Risk and Reliability Impacts of Approaches

As explained above, the Company has analyzed the number of customers likely to have their natural gas service interrupted in the event of different levels of capacity disruption based on the Company's ability to shut-off service to specific large customers or sections of the Aquidneck Island distribution network to shed load. This analysis is meant to be indicative of the magnitude of customer service interruptions and not a definitive analysis.[41]

The Company analyzed different levels of reductions of AGT throughput of 25%, 50%, 75%, and 100% of the 1,045 Dth/hour of capacity for which the Company plans. The Company analyzed each long-term solution in terms of these estimated customer service interruptions over time.[42] The tables below present a select set of results to illustrate the insights provided by this analysis.

[41] This analysis looks at distributions systems on the island that could be shut down relatively quickly; it did not look at targeted prioritization of large customers for load-shedding in a contingency event.

[42] For the purposes of this study, the Company updated an initial customer curtailment analysis done in 2019 for upstream issues that reduce pipeline gas deliveries into Portsmouth as well as for the loss of the Old Mill Lane portable LNG operations. The original analysis evaluated interrupting service to a combination of large-use customers, individual distribution systems, or areas/zones of the low-pressure system in Newport. Regarding the Newport low-pressure system, three zones of approximately 4,000, 1,500, and 1,100 customers were identified based on 16 existing distribution valves that have been confirmed for availability/operability.

Table 25 shows how Old Mill Lane portable LNG provides sufficient capacity presently to largely avoid customer service interruptions even in the face of the loss of nearly 50% of the expected gas capacity from AGT at Portsmouth during extremely cold conditions (i.e., design day conditions of 68 HDD, -3 degrees Fahrenheit). Even with loss of 100% of AGT capacity due to a disruption, Old Mill Lane LNG could support service to the majority of customers on Aquidneck Island. As demand is projected to grow over time, for any given level of AGT capacity disruption, expected customer service interruptions would grow, all else equal. Table 25 also shows how when Old Mill Lane portable LNG is paired with incremental gas energy efficiency and gas demand response efforts on Aquidneck Island that largely offset projected gas demand growth, the degree to which the LNG capacity limits customer service interruptions in the face of a disruption to AGT can stay relatively constant through 2034/35. Varying levels of incremental gas energy efficiency and demand response will preserve the contingency benefits of the LNG capacity to varying degrees.

Table 25: Estimated Customer Service Interruptions in a Contingency Event (AGT Disruption) under Design Day Conditions with Old Mill Lane Portable LNG in Service

% Reduction in Capacity Available from AGT during Design Day (68 HDD) Conditions	Estimated % of Customers with Service Interrupted with Loss of AGT Capacity		
	Old Mill Lane Portable LNG 2020/21	Old Mill Lane Portable LNG 2034/35	Old Mill Lane Portable LNG with Incremental DSM 2034/35
0%	0%	0%	0%
25%	0%	0%	0%
50%	1%	16%	0%
75%	24%	36%	20%
100%	44%	57%	44%

Table 26 shows how the Navy Site Permanent LNG provides contingency capacity to reduce customer service interruptions in the face of loss of AGT capacity due to a disruption. The LNG options at a Navy site provide less contingency capacity than Old Mill Lane portable LNG does because the Navy sites cannot support as much gas capacity as the Old Mill Lane site owing to hydraulic limitations of the gas distribution network. The table also shows how the pairing of incremental demand-side measures with the Navy Site Permanent LNG option can limit the degree to which projected customer demand growth would increase the number of customer service interruptions for a given level of AGT capacity disruption over time. The results in this table are generally applicable across all the alternative LNG options.

Table 26: Estimated Customer Service Interruptions in a Contingency Event (AGT Disruption) under Design Day Conditions with Permanent LNG Storage at Navy Site in Service

% Reduction in Capacity Available from AGT during Design Day (68 HDD) Conditions	Estimated % of Customers with Service Interrupted with Loss of AGT Capacity		
	Navy Site Permanent LNG 2026/27 (assumed first year in service)	Navy Site Permanent LNG without Incremental Demand-Side Measures 2034/35	Navy Site Permanent LNG with Incremental Demand-Side Measures 2034/35
0%	0%	0%	0%

25%	0%	0%	0%
50%	15%	16%	16%
75%	35%	36%	36%
100%	56%	64%	58%

The following Table 27 shows projected customer service interruptions in the face of AGT disruptions in the case of the non-infrastructure solution. The table shows the winter of 2026/27 for comparison to the LNG option above and the final year of the analysis timeframe. In the winter of 2026/27, the non-infrastructure solution would still rely on Old Mill Lane portable LNG being in operation, which would lead to even fewer customer service interruptions for a given level of AGT disruption because the incremental demand-side measures would reduce total demand on Aquidneck Island. In the winter 2034/35 analysis, Old Mill Lane portable LNG has been phased out, and the absolute reduction in demand from incremental demand-side measures means that this solution can provide comparable levels of resilience in the face of AGT disruptions of up to 50% of pipeline capacity under design day conditions. However, the table also shows how the nature of resilience from a pure non-infrastructure approach is different than under an infrastructure approach. At the most extreme, demand-side measures cannot meet any customer demand in the event of a 100% disruption to AGT. In contrast, per the tables above, the options for LNG capacity on Aquidneck Island would limit customer service interruptions to an estimated 44-64% of customers in the event of a 100% disruption to AGT.

Table 27: Estimated Customer Service Interruptions in a Contingency Event (AGT Disruption) under Design Day Conditions with the Non-Infrastructure Solution

% Reduction in Capacity Available from AGT during Design Day (68 HDD) Conditions	Estimated % of Customers with Service Interrupted with Loss of AGT Capacity	
	Old Mill Lane Portable LNG Still in Place 2026/27	LNG Phased Out 2034/35
0%	0%	0%
25%	0%	0%
50%	0%	16%
75%	4%	63%
100%	35%	100%

Unlike the other options, an AGT project would address the underlying causes of the capacity vulnerability with AGT, so an analysis like those above is not relevant in terms of gauging how an AGT project would address the capacity vulnerability need.

11. Decarbonization of Heating

11.1. Decarbonization Pathways for Heating

The Resilient Rhode Island Act, established in 2014, set a state-wide target of achieving greenhouse gas emission reductions below 1990 levels of 80% by 2050. National Grid is committed to supporting achievement of Rhode Island’s long-term decarbonization goal along with providing safe, reliable, and affordable service to its customers.

Governor Raimondo launched the Heating Sector Transformation Initiative in 2019, which directed the Division of Public Utilities and Carriers (DPUC) and the Office of Energy Resources (OER) to lead a "Heating Sector Transformation with the goal of reducing emissions from the heating sector while ensuring Rhode Islanders have access to safe, reliable, and affordable heating." In response to the Governor's order, the DPUC and OER led an effort which culminated in a report being issued in April 2020 which recommended pathways to decarbonization. The report investigated decarbonization opportunities in three broad areas: 1) energy efficiency; 2) replacing fossil heating fuels with carbon-neutral renewable gas or oil; and 3) replacing fossil fuel boilers and heaters with electric ground-source or air-source heat pumps. The report concluded that there was "no clear winner" to heating sector decarbonization, and its recommendations included "enacting a set of technology-neutral measures that will reduce the carbon intensity of all energy sources used for heating" as well as "[c]omplementary fuel-neutral policies that improve building efficiency. In addition, the report recommended that "policies should support both the learning and informing stages, to begin to address the uncertainties, collect information that will be necessary for the transformation, and ensure a widespread understanding of the solutions and their implications" and that "[r]egulatory changes can enable the transformation, addressing barriers and facilitating progress on any or all of the pathways," while "policies that create structures to identify and capitalize on natural investment opportunities will also enable the transformation."

In keeping with the findings of the Heating Sector Transformation report, multiple long-term pathways can deliver a deeply decarbonized energy system for Rhode Island. Most relevant to the focus of this study, there is a growing body of evidence in decarbonization pathways analysis that achieving 2050 decarbonization targets is more cost-effective and resilient through tighter integration of electric and gas networks, especially in cold climates. These studies conclude that low- and zero-carbon fuels (i.e., biogas and hydrogen) that replace traditional natural gas in gas networks can have a significant role, and that by avoiding overbuilding of electricity generation and networks, while minimizing invasive home equipment retrofits, these multiple-fuels pathways are in fact more cost-effective than scenarios exclusively reliant on electrification for the decarbonization of heating. Much of the most advanced analysis to date of decarbonization of heating in cold climates like Rhode Island's has been done in the UK and Europe. For example:

- In Imperial College's 2018 study "Analysis of Alternative UK Heat Decarbonisation Pathways" their conclusion is that a "hybrid" pathway based on high-efficiency heat pumps coupled with gas for peak heating demand conditions or low renewable output would be the least-cost option for the UK.
- In Navigant's 2019 study "Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain," their conclusion is that "a balanced combination of low carbon gases and electricity is the optimal way to decarbonize the [Great Britain] energy system and reach net-zero emissions by 2050."
- Guidehouse's 2020 study "Gas Decarbonisation Pathways 2020–2050" finds that across Europe, gas and electric network integration is a crucial element to decarbonization: "a smart energy system integration means that renewable and low carbon gases are transported, stored, and distributed through gas infrastructure and are used in a smart combination with the electric grid to transport increasing amounts of renewable electricity."

11.2. A Hydrogen Hub on Aquidneck Island

Securing a new, large site suitable for portable LNG and/or LNG storage on Navy property also provides an opportunity to make use of the site for activity to produce, store, and distribute hydrogen as a low- or zero-carbon fuel. While there are several unknowns and details that remain to be worked out, a Navy-owned site could be used for hydrogen in different ways and via a phased approach.

The hydrogen blending section of this paper describes an option that could be co-located with portable LNG or LNG storage at a Navy site, with an electrolyzer system sized to produce hydrogen from water and electricity in quantities that would provide up to 20% by volume blend in the nearby gas network. The concept of co-locating this facility with portable LNG or LNG storage facilities leverages the investment in the LNG solution to create opportunities for deploying hydrogen, which is a key component of a deeply decarbonized heating sector.

The development of a hydrogen hub at a Navy site could also include identifying storage systems with insulation levels that allow storage of either LNG or liquefied hydrogen (LH2). In the first phases of the transition at the site, the electrolyzer plant can grow to reach a supply level serving up to 20% of the winter peak supply calculated to be roughly 1,500 Dth/day in 2035 per the analysis in this study. Some form of hydrogen storage (likely compressed hydrogen storage) would need to be used to ensure a steady supply of hydrogen for the network during winter demand periods.

In the future, the LNG storage tanks could be repurposed for LH2 creating a regional hydrogen supply facility on Aquidneck Island. Economics will dictate whether this new storage facility would use the hydrogen from the on-site electrolyzer to liquefy and store locally or whether it would be more practical to source LH2 from an area with excess or low-cost electricity. The electrolyzers would continue to provide supply in either scenario. This hub-spoke model has been used for years in the LNG industry where a centrally located liquefaction or import facility distributes LNG in bulk to regional storage centers that are closer to the customer base. An LH2 hub is in operation in Massachusetts today serving satellite fuel-cell electric vehicle hydrogen fueling stations. Another hydrogen liquefaction facility is being built in northern Nevada to serve the California hydrogen market.

Investing in hydrogen at a Navy site could eventually provide a hub for a 100% hydrogen gas distribution network. The concept is for a 100% hydrogen network to be built out from a central feeder system that could utilize a Navy LNG facility as a local supply hub. Detailed analysis of the gas network infrastructure would identify areas that could be co-opted from the existing gas network with minimal to significant replacements. National Grid is closely following project developments overseas as Europe and Asia-Pacific attempt to decarbonize gas networks through hydrogen while building critical safety-based evidence for such conversion.

11.3. Decarbonization Considerations for the Potential Long-Term Solutions

The Company considered the implications of each of the potential approaches to address the long-term needs on Aquidneck Island for decarbonization. The table below summarizes those implications in terms of such themes as the relative GHG-intensity of different options, the ability for provide increasingly low-carbon fuel in the future, and the ability to “right size” gas capacity should Rhode Island choose to pursue a decarbonization pathway that relies heavily on heat electrification. Across all of the infrastructure approaches below, addressing the gas capacity needs on Aquidneck Island enable the Company to continue to connect or convert customers who would otherwise use more carbon-intensive delivered fuels (oil and propane).

Table 28: Decarbonization Implications and Considerations

Approach	Implications and Considerations for Decarbonization
Continue Old Mill Lane Portable LNG	
Old Mill Lane Portable LNG	LNG has a higher carbon intensity than pipeline gas; however, with portable LNG serving only as an infrequently used peaking resource, the actual GHG emissions from this option are expected to be de minimis. An LNG peaking resource is consistent with a decarbonization pathway that relies on increasing levels of renewable natural gas. A temporary portable LNG option provides optionality should decarbonization policies in Rhode Island lead to a long-term decline in natural gas demand that make the peaking resource and contingency capacity no longer necessary for Aquidneck Island.
New LNG Solution	
LNG Barge	LNG has a higher carbon intensity than pipeline gas; however, with LNG serving only as an infrequently used peaking resource, the actual GHG emissions from this option are expected to be de minimis. An LNG peaking resource is consistent with a decarbonization pathway that relies on increasing levels of renewable natural gas. This approach also provides optionality. The LNG barge would likely be provided by a vendor with a long-term contract with the Company. If at the end of the term of the contract, decarbonization efforts have reduced gas demand and obviated the need for the LNG barge to meet peak demand or provide contingency capacity, the Company can simply choose not to extend or renew the barge contract.
Portable LNG at Navy Site	LNG has a higher carbon intensity than pipeline gas; however, with LNG serving only as an infrequently used peaking resource, the actual GHG emissions from this option are expected to be de minimis. An LNG peaking resource is consistent with a decarbonization pathway that relies on increasing levels of renewable natural gas. Moreover, the new Navy site creates the opportunity to develop a hydrogen production, storage, and distribution hub. Should decarbonization policies in Rhode Island lead to a long-term decline in natural gas demand that eliminates the need for an LNG peaking resource and contingency capacity on Aquidneck Island, the portable LNG operation can we ended.

Permanent LNG Facility at Navy Site	LNG has a higher carbon intensity than pipeline gas; however, with LNG serving only as an infrequently used peaking resource, the actual GHG emissions from this option are expected to be de minimis. An LNG peaking resource is consistent with a decarbonization pathway that relies on increasing levels of renewable natural gas. Moreover, the new Navy site creates the opportunity to develop a hydrogen production, storage, and distribution hub, and the Company can explore “future-proofing” the permanent LNG storage tanks to make them capable of storing LH2 in the future. Should decarbonization policies in Rhode Island lead to a long-term decline in natural gas demand that eliminates the need for an LNG peaking resource and contingency capacity on Aquidneck Island but without a transition to low- and zero-carbon fuels in the gas network, the Company would need to “right size” its capacity portfolio given the long-lived permanent LNG storage asset.
Portable LNG at Navy Site transition to Permanent LNG Facility	Same as above.
AGT Pipeline Project	
AGT Project	Pipeline gas has lower carbon-intensity than LNG. Gas pipeline capacity is consistent with a decarbonization pathway that relies on increasing levels of renewable natural gas. An AGT expansion project that provided access to more upstream gas capacity could allow Aquidneck Island to tap into lower cost renewable natural gas resources for more of its total demand. More work is needed to determine the role of current gas pipeline capacity in a long-term decarbonization pathway that relies on high blends of hydrogen. Should decarbonization policies in Rhode Island lead to a long-term decline in natural gas demand, the Company would seek to “right size” its contracted gas capacity as long-term agreements come up for renewal.
Non-Infrastructure	
Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification	Gas demand response would likely lead customers to fuel switch from natural gas to more carbon-intensive fuel oil in most cases; however, given the limited expended number of events, the actual GHG emissions impact would likely be small. Moreover, as part of developing DR programs, National Grid could support the use of biofuels or supplemental electrification in lieu of fuel oil. While gas energy efficiency and some degree of heat electrification are essential components of any decarbonization pathway, a non-infrastructure approach would direct Rhode Island spending toward aggressive demand-side programs specific to Aquidneck Island when

	the same level of spending would likely achieve greater GHG emission reductions if spread across the state and focused on less costly measures (especially in the case of subsidizing the conversion of existing gas customers to electric heat pumps). Moreover, as the evidence above suggests, a gas network delivering low- or zero-carbon fuel could be a key to a least-cost decarbonization pathway for Rhode Island, in which case investing in converting gas customers to heat pumps on Aquidneck Island could prove suboptimal when the gas network is decarbonized.

12. Coordination with Rhode Island Energy Policies, Programs, or Dockets

Supply- and demand-side approaches to meeting customer needs are contemplated and vetted pursuant to various legislative and regulatory requirements today. Every two years, the Company files its supply-side approaches for meeting statewide customer gas demand through the submission of the Company's Long-Range Resource and Requirements Plan pursuant to R.I. Gen. Laws § 39-24-2. The Long-Range Plan consists of an energy plan for a five-year period and is designed to demonstrate that the Company's gas-resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least-cost. The Company has also focused on reducing customer demand via its gas energy efficiency programs which advance policies established as part of Least Cost Procurement. Least Cost Procurement, established per R.I. Gen. Laws § 39.1.27.7, requires Rhode Island electric and natural gas distribution companies to prudently and reliably invest in all cost-effective energy efficiency before the acquisition of additional supply and has successfully resulted in nearly 3.5 million annual MMBTU saved over the last ten years. Additionally, just this year, the RI PUC adopted an updated version of the Least Cost Procurement Standards which requires that the Company should incorporate gas into its System Reliability Procurement process and describe how it intends to procure "non-pipeline alternatives" opportunities to meet gas distribution system needs.

The Company hopes to apply the lessons learned from this study to evaluate the need, options, and potential solution approaches towards standing up and incorporating an analysis of non-pipeline alternatives into our planning efforts as gas is incorporated into the System Reliability Procurement plan.

13. Stakeholder Input and Next Steps

13.1. Stakeholder Engagement

National Grid wants to ensure that any final recommendations for Aquidneck Island be inclusive of customer and stakeholder sentiment and feedback. As such, the Company will share the study with key stakeholders and the public and solicit their feedback and questions. A key stakeholder engagement venue is the Aquidneck Advisory Group (AAG), which was created in June of 2019 to more directly address and guide energy solutions for Aquidneck Island. The AAG includes public officials (town administrators), economic development groups, local chambers of commerce, the DPUC, and state organizations (such as OER). Feedback from the

AAG and other key stakeholders will help National Grid make a final recommendation which will be pursued and formally presented via the appropriate filing process (the type of filing will depend on the recommendation). The stakeholder engagement plan is summarized in the table below:

Engagement	To Whom	Target Date(s)
Briefings on Proposed Study Options: Provide key stakeholder briefing/summary on options from study/solicit feedback.	Key Division personnel, AI town administrators, OER, Gov's office, Key Legislators.	Sept 1-11
Aquidneck Advisory Group: Formal Briefing of Study Options – solicit feedback on preferred option	AAG Members – Division, OER, AI Town Administrators, AI Economic Development Groups, Newport Chamber.	Sept 14
SRP Technical Working Group Meeting: Formal Briefing on study options – share current feedback on preferred option/solicit additional feedback	System Reliability Procurement TWG Members	Sept 23
Public Awareness: Provide communications on approach and refined set of recommendations (launch of website). Offer notices in bill mailings and social media. Offer avenue for public feedback.	Open to public	Sept 21 – Dec 1
AI Energy Matters Open House: Virtual open house to address all energy matters. Agenda will include an overview of approach/all considerations, with a narrowed set of final recommendations. Solicit public feedback.	Open to public (AI)	Oct 14

13.2. Next Steps to Address Aquidneck Island Needs

As described above, the Company will solicit stakeholder input related to the potential options to meet the gas capacity constraint and vulnerability needs on Aquidneck Island. The Company intends to finalize a recommendation for the best solution by December 2020 and to take steps to implement the solution thereafter.

The next steps in terms of implementation depend on the nature of the long-term solution. Some options would likely entail including investments in the Company's next gas infrastructure, safety, and reliability (ISR) plan to be filed by the end of 2020 for regulatory approval and funding. Other options would have different implementation pathways, including potentially the System Reliability Procurement (SRP) Plan or future years' annual gas energy efficiency program plans. Moreover, some options—particularly heat electrification—have no immediate pathway to implementation and will require consultation with regulators and key stakeholders to determine whether and how they might be implemented.

13.3. Optionality and a Final Long-Term Solution

National Grid and stakeholders may consider the potential benefits of preserving optionality in pursuit of a long-term solution for Aquidneck Island. There may be value in not "over deciding" on the long-term solution in the near term but rather keeping options open. Several factors support trying to retain optionality, including:

- Aside from the continued reliance on Old Mill Lane portable LNG, each of the other long-term solutions has a multi-year implementation timeline
- The Company has only conceptual cost estimates for some long-term solutions, and new information or additional engineering or other analysis can refine and reduce the uncertainty of cost estimates
- Many options face implementation uncertainty and risk (e.g., required permits might be denied for infrastructure solutions)

For example, preserving valuable optionality and not "over deciding" at this stage might mean that after receiving stakeholder feedback, the Company could:

- Recommend some level of incremental demand-side measures on Aquidneck Island that might be "no regrets" under any long-term solution
- Rule out a subset of potential long-term solutions based on stakeholder feedback and evaluation against cost, feasibility, etc.
- Recommend near-term efforts to advance a subset of potential long-term options, such as through further engineering and design to refine cost estimates and further detailing of implementation requirements and risks

In this example, the Company could then update the evaluation of a subset of options with more complete information that would enable a final decision on a long-term solution.

Optionality does come with a cost from investing time and money in advancing at least some potential solutions that will not be fully implemented, and not all options can be pursued in parallel. However, a deliberate approach to preserving optionality can create value in terms of enabling a more fully informed final decision and providing a fallback option should one preferred solution encounter insurmountable delays or implementation roadblocks.

14. Technical Appendix for Non-Infrastructure Resources

National Grid has looked at an extensive set of solutions that might be used to address the capacity constraint and the capacity vulnerability needs on Aquidneck Island. It sought to include a wide range of technically feasible options, even where some options may not have clear implementation pathways or may face substantial hurdles, so as not to prejudge options that might ultimately prove to be appealing on key evaluation criteria or that might garner substantial stakeholder support and thus warrant changes - regulatory or otherwise - that would enable their implementation.

The capacity constraint identified on Aquidneck Island already reflects energy efficiency (EE) that National Grid has already been pursuing throughout Rhode Island. In addition to that, each long-term solution approach also includes some amount of incremental demand-side management in the form of increased EE, demand response (DR), and/or electrification. The levels of incremental demand side management for each solution are identified in Table A-1.

Table A-1: Summary of Incremental Demand-Side Programs for Solutions

Solution	EE level	DR level	Electrification level
Old Mill Lane Portable LNG with incremental demand-side management	Reach ~75% of homes and ~33% of businesses by 2034/35	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	None
New LNG Solution (Portable LNG or Permanent LNG at New Navy Site, or LNG Barge)	Reach ~75% of homes and ~33% of businesses by 2034/35	Continue large commercial DR	None
AGT Project with incremental demand-side management	Reach ~65% of homes and ~33% of businesses by 2034/35, focusing on weatherization	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	Electrify ~13% of forecasted gas customers by 2034/35
No Infrastructure (Phase out Trucked LNG @ OML as-soon-as-possible exclusively through incremental DSM)	Reach ~80% of homes and ~33% of businesses by 2034/35, focusing on weatherization	Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR	Electrify ~63% of forecasted gas customers by 2034/35

Incremental Energy Efficiency Assumptions

This section describes the key inputs into the incremental energy efficiency (EE) analysis. The key inputs are

- Scenario composition – what EE measures are included
- Energy savings
- Measure life
- Participation (annual + cumulative)
- Costs

The sources for these inputs are primarily the National Grid EE program data and the 2020 Rhode Island Market Potential Study. The framing of the various levels of EE incorporated into the solutions analyzed precedes the discussion of the derivation of these inputs.

Scenario Composition

With current levels of EE already being accounted for in the demand forecasts for Aquidneck Island, it was assumed that incremental EE beyond the usual set of EE measures would be required to help close the demand gap and meet contingency needs.

We limited the analysis to HVAC and envelope measures for residential (including income-eligible and non-income eligible) and commercial customers. The HVAC measures include efficient boilers and furnaces, thermostats and energy management systems, and distribution system improvements such as heat recovery and demand control ventilation, duct insulation and duct sealing, and steam traps. The envelope measures include intensive air sealing and insulation. These measures offer peak day savings which are highly coincident with the design day need on Aquidneck Island.

The savings presented below are typically incremental to current baseline amounts of efficiency and are achieved by increasing customer participation and by reaching higher levels of savings from customers who were already expected to participate (for example, going from R-30 insulation to R-40 in an attic).

As seen in Table A-1, incremental EE is assumed in all solutions – however, the level of incremental EE implemented varies. The assumptions behind this incremental EE program are discussed below.

Energy Savings

Energy savings within the model is based on the measure life and annual savings in the two measure categories, which includes measures discussed above. The size of the EE resource was determined from an analysis of data from the recently completed Rhode Island Market Potential Study (the "RI Potential Study").[43] This study presented three cases for statewide achievable EE: low, mid, and max. We created two scenarios for EE savings based on this information: a moderate scenario (the difference between the mid and low cases) and an aggressive scenario (the difference between the max and low cases). This provided an annual amount of savings, in MMBtu/year. We scaled the statewide potential for these measures to Aquidneck Island using information about the percentage of sales to Aquidneck Island customers. The levels of EE in each solution use the assumptions from the two scenarios and

[43] https://rieermc.ri.gov/rhode-island-market-potential-study-2021-2026/

choose the amount of EE based on the need and the contributions of other components of the solution. In addition, we separately estimated savings as a percent of natural gas sales in each scenario.

Annual Savings

In both scenarios, we assumed participants to be a combination of customers who would not otherwise participate and customers who were already expected to participate but would be incentivized to take incremental steps. The incremental savings per participant from the "already participating" customers is less than the savings from new participants because they are starting at a higher level of efficiency.

The incremental efficiency program was assumed to have the following savings per customer, in therms per year:

Table A-2: Annual Savings per Participant, therms/yr.

	New Participants	Already Participating
Commercial (All measures)		
• **Moderate Scenario**	310	28
• **Aggressive Scenario**	380	100
Residential (HVAC)		
• **Moderate Scenario**	8.7	0.8
• **Aggressive Scenario**	11	3.0
Residential (Weatherization)		
• **Moderate Scenario**	14	1.3
• **Aggressive Scenario**	18	4.9

The amount of annual savings per customer in these estimates is comparable with savings estimates for these measures from historic program implementation. Generally, six years is assumed to be necessary in most situations to achieve the sustained levels of participation in both scenarios. Given the program ramp-up, the aggregated savings from the incremental EE across all customers leads to an annual incremental savings as a percent of sales of 0.3% in the moderate scenario and 0.6% in the aggressive scenario for Aquidneck Island. When combined with base goals currently included in the 2021-23 draft Least Cost Procurement Plan of 1.1% savings as a percent of gas sales[44], this implies a savings as a percent of gas sales of 1.4% to 1.7% in the Aquidneck communities in the moderate and aggressive scenario, respectively.

These annual savings are converted to design day savings using a design day factor of 1.3%. This is based on the ratio of heating degree days on the design day versus the total throughout a normal weather year, as energy consumption for space heating (and therefore savings from weatherization) correlate highly with heating degree days. In addition, these retail savings are

[44] At the time of this AI analysis and report, the 2021-2023 Least Cost Procurement Plan was in draft form and scheduled to be finalized and filed on or before October 15th.

converted to wholesale savings values using a factor of 102% based on the relationship between retail and wholesale demand forecasts.

With an assumed measure life of at least 15 years for all measures, after the install year, each installation contributes savings to all of the following years in the analysis. More information on measure life is presented below.

While code changes to require more efficient boilers may occur over the life of this initiative, we are not accounting for specific code changes. The EE increase will be the same as modeled here whether achieved through incentives, code changes, or a combination of the two. If the efficiency increase is achieved with lower incentives, the overall utility implementation cost will decrease while overall installation costs would be the same.

Avoided Double Counting of Savings

In several potential solutions, EE is paired with DR and electrification. To avoid the double counting of gas savings from EE followed by DR and electrification, the analysis assumes EE happens first, which achieve gas savings for the life of the measure, reducing the average usage per customer. The amount of electrification and DR savings are then based on that reduced usage per customer. Had there been no EE, a single electrification would have yielded more savings.

It is somewhat counterintuitive that a now fully electric customer could still have persisting gas EE savings, but some of the savings from electrifying are still attributed to the gas EE. Note that these are independent events and participating in EE one year does not change the likelihood that the customer will electrify after that.

For solutions with electrification (like the max No Infrastructure solution), there is a discount on the amount of HVAC participation to account for the fact that a customer would not complete the high-efficiency gas installs. For solutions without electrification, that discount is not applied.

Measure Life

Each measure has a typical measure life. Based on an analysis of measures within the weatherization and HVAC categories, Table A-3 includes the average measure lives by measure category.

Table A-3: Measure Life (years)

	Envelope	HVAC
Residential	20	19
Commercial	25	15

Participation: Program Ramp-Up and Customer Adoption

In both scenarios, we assumed participants to be a combination of customers who would not otherwise participate and customers who were already expected to participate but would be incentivized to do more. The incremental savings per participant from the "already participating" customers is less than the savings from new participants because they are starting at a higher level of efficiency.

Using historic National Grid information about the savings per customer, the number of customers needed to achieve the annual savings levels of the moderate and aggressive scenarios were determined. This was added to baseline levels of participation and compared for reasonableness to the number of accounts on Aquidneck Island. The number of eligible customers is based on National Grid data and includes single family, multifamily, and commercial customers, including income qualified customers, and takes into account customers that have already participated in recent years. Generally, a ramp-up over a 6-year period is assumed in most solutions to allow for robust program and infrastructure development.

In the No Infrastructure solution – which corresponds to the maximum amount of EE – by 2035, this ramp up results in up to ~35% of commercial customers and ~80% of residential customers on Aquidneck Island participating in the base and incremental HVAC upgrades and/or weatherization programs. Some customers are expected to have completed both weatherization and HVAC upgrades while some will do only HVAC upgrades.

Basis for Customer Adoption

This section further examines the reasonableness of the penetration estimates for the weatherization/envelope measures and the HVAC-related measures in the context of historic program participation rates and the overall number of customers on Aquidneck Island.

Weatherization/Envelope

Table A-5 shows the number of past and forecast weatherization jobs per year from EE program data for Aquidneck Island customers and derived from RI Potential Study file data.[45] Note that both the moderate and aggressive cases generally assume a 6-year ramp up to achieve this level of annual jobs. The number of moderate and aggressive scenario jobs was determined by dividing estimates from the RI Potential Study by historic average savings per participant from National Grid. This step was needed because the participation units in the RI Potential Study file were not always a number of dwellings; sometimes the units were in square feet or other parameters.

Table A-4: Annual Weatherization Jobs on Aquidneck Island[1]

	Residential	Commercial
Historical AI (2016-2018)	250-296	41-53
Moderate case	265	33
Aggressive case	315	30

[1]Not incremental to base case

With the estimates of the annual number of jobs, the cumulative weatherization completions as share of total AI building stock, is shown in Table A-5. These estimates assume that 9% of gas-heated building stock was weatherized as of 2019.

Table A-5: Cumulative Weatherization Completions in 2034

	Residential	Commercial
Statewide weatherization[1]	33%	28%
Moderate case for AI	36%	31%
Aggressive case for AI	41%	30%

[1]Based on comparable number of residential and commercial weatherization jobs annually that have been completed historically continued through 2034.

[45] The Historic AI information includes homes heated with delivered fuels and electricity. About 60% of these home heat with natural gas. This does not change the savings per household.

Some homes on Aquidneck Island have barriers to weatherization such as knob and tube wiring, asbestos, or other conditions that need to be addressed before weatherization can occur. The number of weatherization jobs completed will be influenced by how many buildings need pre-weatherization barrier remediation. The assumed share of jobs requiring pre-weatherization barrier work is shown below in Table A-6.

Table A-6: Percent of Weatherization Jobs Needing Pre-Weatherization Work

	% of Jobs Needing Pre-Weatherization Work
Moderate case	30%
Aggressive case	50%

Source: National Grid estimate for residential and commercial customers.

For context, pre-pandemic, approximately 50% of customers had some form of pre-weatherization barrier. The pre-pandemic closure rate (number of home energy assessments leading to completed weatherization projects) when no barrier was present was approximately 40 to 45%, while the closure rate for customers with pre-weatherization barriers was 20 to 25%.

Further, with the COVID-19 recovery 100% incentive offer, closure rates are about 60%, which indicates the effectiveness of 100% rebates and leaves 40% of customers as potential candidates for barrier remediation to help increase closure rates and increase participation. Based on this, the numbers in Table A-6 are an estimate of the percentage of projects that will require pre-weatherization barrier remediation to participate. As the aggressive case will need to reach more customers, it is assumed that a higher proportion of jobs will need pre-weatherization work.

HVAC

To assess the reasonableness of potential HVAC EE participation, we examined three areas –

- High efficiency boilers & furnaces: replace on burnout (ROB)
- High efficiency boilers & furnaces: early replacement (ER)
- Other HVAC measures

High Efficiency Boilers & Furnaces: Replace on Burnout (ROB)

We estimated the number of ROB HVAC upgrades from the RI Potential Study detail file for residential and commercial “market units adopted” for ROB and early replacement (ER) furnaces and boilers scaled from the statewide analysis to Aquidneck Island. For Residential heating equipment, the numbers provided in the file are the count of units; for Commercial heating, the units are expressed in kBtu/hour of heating capacity and are converted to number of systems assuming an average system size of 1200 kBtu/hour (this assumption is only to provide an estimate of the number of systems and does not affect overall EE savings). It is assumed that Aquidneck Island installations are in the same proportion as the rest of the state as modeled by the RI Potential Study.

Table A-7: Total Annual Boiler/Furnace Replacements on Aquidneck Island [1]

	Residential	Commercial
Base	120	16
Moderate case	360	20
Aggressive case	535	22

[1]Not incremental to base case and includes ROB and ER.

The RI Potential Study data file includes the following measures in the above commercial boiler/furnace counts; there are no early replacement boilers or furnaces for Commercial customers:

- HVAC Boiler < 300 kBtu/hr Tier 1 ROB
- HVAC Boiler ≥ 300 kBtu/hr Tier 1 ROB
- HVAC Boiler < 300 kBtu/hr Tier 2 ROB
- HVAC Boiler ≥ 300 kBtu/hr Tier 2 ROB
- Furnace ROB
- Combo Condensing Boiler/Water Heater 90% AFUE ROB
- Combo Condensing Boiler/Water Heater 95% AFUE ROB
- Steam Boiler ROB

If we assume a 20-year life for heating equipment, then 1 out of 20 of boilers and furnaces fail each year; this is approximately 640 residential and 95 commercial failures annually. Table A-8 provides the percentage of those ROB instances anticipated; reaching these customers will require enhanced market coordination in addition to incremental incentives.

Table A-8: Annual Boilers and Furnaces Replaced "On Burnout"[1] and Percent of Annual Market

	Residential	% of annual market	Commercial	% of annual market
Base	110	16%	16	16%
Moderate case	295	45%	20	21%
Aggressive case	420	65%	22	23%

[1]Not incremental to base case in 2026.

As with the weatherization data, the annual replacements are steady state numbers following a ramp up period.

High Efficiency Boilers: Early Replacements

The following information is from the RI Potential Study detail file for residential and commercial "market units adopted" for early replacement boilers. The RI Potential Study measures include early replacement for residential furnaces only; neither early replacement boilers nor commercial early replacements are considered.

Table A-9: Annual Early Replacement Furnaces[1]

	Residential	Commercial
Base	12	0
Moderate case	65	0
Aggressive case	115	0

[1]Not incremental to base case

High Efficiency Gas Systems

Based on the assumptions discussed above, by 2034 between ~50 and 60% of residential customers and ~30% of commercial customers will install high efficiency gas equipment. This share of high efficiency systems assumes that, in 2019, approximately 15% of gas heating systems are already high efficiency based on historic participation information.

However, in solutions with maximum electrification, there will be no high efficiency gas HVAC system replacements since they will be electrified.

Other HVAC Measures

The HVAC category includes measures that address boilers and furnaces, control, and miscellaneous heating. Some participants in HVAC programs will not only install high efficiency gas systems, some will install Wi-Fi thermostats or distribution system efficiency upgrades.

Of the measures included within the HVAC category, boilers and furnaces account for the largest portion of annual gas savings for both residential and commercial participants. Of measures other than boilers and furnaces, the RI Potential Study has granularity only for implementation of residential Wi-Fi thermostats. Data for residential Wi-Fi thermostats is shown below for residential "market units adopted" for Wi-Fi thermostats. It is generally assumed that the moderate and aggressive cases will take 6-years to ramp up to this number of installations.

Table A-10: Annual Installations of Residential Wi-Fi Thermostats[1]

Annual Thermostat Installations	
Base	185
Moderate case	326
Aggressive case	479

[1]Incremental to base case

At this annual rate of participation, the cumulative share of residential customers that will have installed Wi-Fi thermostats by 2034 is ~60% in the moderate case and ~75% in the aggressive case, assuming that, in 2019, 15% of residential customers already have Wi-Fi thermostats based on National Grid historic participation data. Based on these rates of participation, most participants will both upgrade their heating system and install a Wi-Fi thermostat.

Program Costs

The aggregate cost for each solution is a combination of aggressive incentives paid to customers, administrative costs, and customer costs for installation costs not covered by incentives; in some cases, we considered and estimated pre-weatherization costs to achieve the higher-levels of weatherization envisioned through 2035.

Customer incentives and costs not covered by incentives are determined from RI Potential Study and National Grid program data. Administrative costs and pre-weatherization remediation costs are determined from National Grid program data.

To determine the overall program costs, we applied a ratio from recent RI EE programs to include costs for program administration (marketing, training, evaluation, internal administration).

Equipment Cost Incentives

Incentive costs are based on data from the RI Potential Study which provided incentives per MMBtu of savings. These were converted to incentives per customer as shown in Table A-14 using data on National Grid historic MMBtu savings per customer from 2016-18. Incentive costs were assumed to increase 2% annually.

In the moderate scenario, these incentives average to around 75% of the total cost of the weatherization and HVAC measures. Customers would be responsible for paying for the balance of project costs. In the aggressive case, the incentives pay 100% of project implementation costs. The 100% incentive cost is determined from the max achievable case in the RI Potential Study that assumes incentives equal to 100% of the incremental cost of the efficiency measure would be necessary to achieve higher amounts of savings.

Table A-11: EE Incentives per Participant

	New Participants	Already Participating
Commercial (HVAC)		
• **Moderate Scenario**	$15,948	$1,450
• **Aggressive Scenario**	$34,790	$9,488
Commercial (Weatherization)		
• **Moderate Scenario**	$3,239	$294
• **Aggressive Scenario**	$7,810	$2,130
Residential (HVAC)		
• **Moderate Scenario**	$1,266	$115
• **Aggressive Scenario**	$2,066	$563
Residential (Weatherization)		
• **Moderate Scenario**	$4,566	$415
• **Aggressive Scenario**	$8,152	$2,223

Incremental Administrative Costs (i.e., beyond incentive costs)

In addition to incentives, administrative costs were added to the implementation costs. This is in line with other EE programs in Rhode Island. The ratio of incentive to total utility cost was determined from National Grid RI's 2019 Year-End Report data file. Participant incentives and sales, technical assistance and training (STAT) costs were summed and divided by total implementation expenses. The remaining percentage of spending (for program planning, marketing, and evaluation) were assumed to be administrative costs. The derived percentage for Energy Star HVAC was used for HVAC; the percentage from EnergyWise was used for

Residential envelope measures; and the percentage for Large Commercial Retrofit was used for Commercial measures.

Table A-12: Incentives as a Portion of Total Program Costs

Customer Segment	Measure	Incentive / Total Utility Cost
Commercial	Envelope	80%
Residential	Envelope	95%
Commercial	HVAC	80%
Residential	HVAC	90%

Pre-weatherization Cost Analysis

The cost for each job requiring pre-weatherization remediation is assumed to be $2,500 per participant based on stated assumptions around the share of participating customers requiring these remediation efforts and an estimated cost per participant.[46] This number is a weighted average estimated cost for the six most prevalent types of barriers (asbestos, vermiculite, knob and tube wiring, indoor air quality, mold, and lead paint) for the years 2016-19, accounting for over 70% of cases. This number was added to the average weatherization incentive cost per customer assuming the percentages of jobs needing pre-weatherization as shown in Table A-7. Note that because fewer than 50% of customers in RI need to be weatherized, National Grid will not have to pursue every customer needing very expensive pre-weatherization measures.

[46] There is minimal data about the need for pre-weatherization remediation for commercial installation. The addition of the cost premium based on residential pre-weatherization remediation is therefore a conservative assumption.

Table A-13: Pre-Weatherization Barriers and Cost for 2016-19

	Total Aquidneck			Typical Cost
Primary Pre-Weatherization Barrier	**Open Jobs**	**Weatherization Complete**	**Grand Total**	
Asbestos	135	34	169	$4,000
Moisture/Mold/Mildew	115	33	148	$2,400
Carbon Monoxide Alarm Needed	2	2	4	
Carbon Monoxide Heating System	21	7	28	
Combustion Gas Spillage	19	6	25	
Depressurization Hazard	17	4	21	
Electrical	54	41	95	
Gas Leak	3	0	3	
Indoor Air Quality	177	121	298	$500
Inoperable Heating System	2	0	2	
Knob & Tube Wiring	150	31	181	$7,500
Lead Paint	16	3	19	$3,000
Open Framing	3	0	3	
Recessed Lights	3	2	5	
Unvented Appliance	5	2	7	
Vermiculite	50	12	62	$5,700
Other	125	17	142	
TOTAL/WTD AVERAGE COST	897	315	1212	$2,503
Top Six Barriers	643	234	877	
Top Six as % of Total	71.7%	74.3%	72.4%	

Source: National Grid EE program data.

Based on the above information, it is assumed that in the moderate and aggressive scenarios, the cost per participant will be offered an additional incentive as follows:

Table A-14: Additional Incentive per Customer for Pre-Weatherization Work

	% of average pre-Wx cost	Additional incentive
Moderate case	50%	$1,250
Aggressive case	100%	$2,500

The $2,500 per customer cost is a weighted average of pre-weatherization measure costs experienced spread out over all participants. On average, remediation of pre-weatherization barriers added 7.0% to the cost of weatherization across all customer weatherization installation costs.

Summary

The key assumptions defining the savings and costs associated with an incremental EE program are shown in Table A-15.

Table A-15 – Summary of Incremental EE Assumptions

Parameter	Assumption	Source
Annual EE Savings by Customer and Project Type	See Table A-2	National Grid historic data
Measure Life by Customer and Project Type	See Table A-3	
Design Day Factor	1.3%	Ratio of design day heating degree days (HDD) to sum of normal year HDD in National Grid's wholesale forecast
Retail to Wholesale Factor	1.02	Based on the comparison of National Grid's daily retail and wholesale forecast
Incentive by Customer and Project Type	See Table A-11	RI Potential Study
Administrative Cost Adder	See Table A-12	2019 Year End Report Data
Pre-weatherization Cost and Incentive Adder	See Table A-14	Estimated cost and weighting from National Grid RI CEM group

Incremental Demand Response Assumptions

Incremental demand response would be necessary to address the supply constraint and contingency targets on Aquidneck Island for both the design day and the design hour. By its nature, the savings from these programs are highly coincident with the constraint, and therefore warrant consideration for each solution.

National Grid currently offers winter gas DR to commercial on Aquidneck Island. National Grid conducted a large commercial DR pilot on Aquidneck in the winter of 2019-20. It had two components: a full-day component where customers entirely curtailed their gas use for 24 hours and a three-hour event component where customers reduced their gas use over a three-hour period.

There are two levels of DR indicated in Table A-1.

- Continue the large commercial DR.
- Recruit additional participants for continued large commercial DR, begin commercial and residential thermostat setback DR.

The levels of DR in each solution are selected based on the need and the contributions of other components of the solution. These definitions are discussed in further detail below.

Adoption

National Grid has a statewide summer electric residential demand response program, chiefly based on thermostat direct load control, and has conducted commercial winter gas demand response pilots on Aquidneck Island. The estimates of penetration and adoption build on the experiences with these efforts.

To ameliorate the design day challenges on Aquidneck Island, National Grid would continue incentivizing two large commercial customers to switch to a different heating fuel for the coldest days. Then, if this program is to be grown, National Grid would pay for up to 14 additional large commercial customers on Aquidneck Island to install backup heating equipment.

Demand response can also ameliorate design hour challenges. To this end, National Grid would offer two additional programs, one for large commercial customers and one for residential customers. The large commercial offering would install a meter at each participant to track event usage, and then call for demand reduction over a three-hour event. It was assumed that this program could reach about another 70 large commercial customers on Aquidneck Island. The residential program would be a thermostat direct load control (DLC) program that slightly lowers the thermostat setpoint to reduce heating consumption during the four-hour event. For this program participation was assumed to roughly 25% of residential heating customers by 2035.

Savings

The two large commercial customers currently participating in the full-day pilot are each expected to save about 300 Dth/day on average in a design day, and the new participants would be expected to save about 90 Dth/day.

For the peak event program, the large commercial participants are assumed to each save 0.54 Dth/hr on the design hour, and the residential participants are assumed to each save 0.0017 Dth/hr on the design hour. These customers would experience some snapback after the event which reduces the design day impact.

This is based on historical event day savings from the statewide program.

Costs

There are assumed upfront costs of $150,000 per participant for each of the new large commercial full day participants, and $4,000 per participant for the new large commercial full day and peak event participants.

There are also incentives for participating customers. There are annual participation incentives per participant of $56,000, $16,800, and $2,700, and $56 for current full day participants, new full day participants, new large commercial peak event participants and new residential peak event participants, respectively. Additionally, there are performance incentives for the large commercial customers of $35 per Dth of peak day reduction per year for the full day program and $75 per Dth of peak day reduction per year for the peak event program.

It is assumed that there are fixed program costs of $100,000 per year for the full day program and $100,000 per year for the peak event program, based on historical program costs and costs for similar DLC programs.

Summary

The key assumptions defining the savings and costs associated with an incremental demand response program are shown in Table A-16 below.

Table A-16: Summary of Incremental Demand Response Program Assumptions

Parameter	Assumption
Large commercial full day max participation	2 current participants, 14 new participants
Large commercial peak event max participation	70
Residential peak event max participation	1,200
Large commercial full day design day savings per participant	300 Dth/day per current participants, 90 Dth/day per new participant
Large commercial peak event design hour savings per participant	0.54 Dth/hr
Residential peak event design hour savings per participant	0.0017 Dth/hr
Large commercial full day incentive per participant	$154,000/cust upfront for new participants, plus $56,000/yr - $18,000/yr
Large commercial peak event incentive per participant	$4,000/cust upfront, plus $2,700/yr
Residential peak event incentive per participant	$56/yr
Non-Incentive Program Cost	$200,000/yr

Incremental Electrification Assumptions

Though incentivizing electrification is not normally within the purview of a gas utility, it is assumed to be necessary here to help address the demand gap on Aquidneck Island as EE and DR reach their limits of achievability. It is assumed that National Grid would need to provide a separate incentive to drive enough customers to adopt electric heating. This can also facilitate adoption of cold-climate heat pumps which will have a higher impact the design day.

Incentivizing incremental electrification on Aquidneck Island is only assumed to be needed as part of two of the solutions – the AGT Project and the No Infrastructure solution. In the No Infrastructure solution, electrification is being used to offset LNG trucking at Old Mill Lane (~60% of today's design hour demand), which requires significantly more electrification than would be needed to close the growing gap on Aquidneck Island as for the AGT Project.

Thus, the No Infrastructure solution is radically different than no infrastructure scenarios typically considered for NWA/NPA opportunities. This solution assumes there is immediate local/state intervention to essentially ban the purchase of new gas heating equipment in favor of electric heating equipment. The solutions are at the limit of converting HVAC system turnover of roughly 5% of current gas customers per year. Additionally, all forecasted new residential heating and commercial gas customers are assumed to be persuaded to instead electrify (these customers are technically considered to be gas-to-electric (G2E), even though they never actually installed gas heating equipment).

Based on our preliminary, aggregated review of summer and winter feeder capacity on Aquidneck Island, there is sufficient winter and summer capacity to accommodate heat electrification in the near term. However, location matters and although there is sufficient capacity in aggregate, individual feeders, feeder sections or secondaries would likely experience loading that produces system thermal and voltage performance concerns. As the amount of heat electrification grows, addressing such concerns would require potentially significant incremental investment on the electric distribution system. National Grid's Electric Distribution Planning and Asset Management team will be engaged to model increasing electric demand in the options that include significant heat electrification.

Customers have two assumed paths for electrification - customers with existing duct work were assumed to opt for a ducted (central) air-source heat pump, while customers without existing duct work were assumed to opt for a ductless mini-split air-source heat pump. Given the higher relative cost, it was assumed that customers would not choose to switch to ground-source heat pumps. However, as discussed in Section 8.9, ground-source heat pumps could offer an alternate path to electrification.

For the residential and small commercial customer populations, the following assumptions are made about the percentage of customers that could be converted as part of this initiative. The residential data comes from the Massachusetts Residential Baseline Study. The commercial data comes from DNV's 2017 Commercial Market Assessment.

Table A-17: Heat Pump Electrification Assumptions

Customer Segment	Future Heating + Cooling	Current Heating	Current Cooling	Share of Customer Segment
Residential	Ductless MSHP, 18 SEER/10.0 HSPF	Gas Boiler,75% AFUE	Room/Window A/C (qty: 5 @ 12,000 Btu/h each), 8 EER	45%
			No A/C	15%
	Central HP, 16 SEER/9.5 HSPF	Gas Furnace,78% AFUE rated	Central A/C, 32,000 Btu/h, 10 SEER/8.5 EER	40%
Small Commercial	Ductless MSHP, 20 SEER/9.0 HSPF	Gas Boiler,75% AFUE	Room/Window A/C, 8 EER	24%
			Mini-Split A/C, 15 SEER	7%
			No A/C	19%
	Central HP, 17.0 SEER/9.0 HSPF	Gas Furnace,78% AFUE rated	Central Split-System A/C, 14 SEER	33%
			Central Packaged A/C, 14 SEER	17%

The assumptions surrounding this program are discussed below.

Ramp-Up and Customer Adoption

An electrification program was assumed to be offered to existing residential natural gas customers on Aquidneck Island, as well as prospective gas customers who currently heat with oil but are planning on converting to natural gas heating. This would reduce the number of current and new gas customers.

Of this population, it was assumed that the majority of electrification would occur from customers considering replacement of their current HVAC equipment. Given a typical 20-year HVAC life, this meant that 5% of current gas customers would consider replacing their HVAC each year, plus all of the forecasted new gas customers (who by definition would be planning to change their HVAC equipment that year). Of this addressable market, some percent would be targeted to electrify with an incentive. In the AGT Project solution, the incentive would be set to aim to electrify roughly a third of these customers each year. For the No Infrastructure solution, the incentive would be set to aim to electrify 100% of these customers each year. That steady-state customer acceptance is assumed to be reached after a 4- to 6-year ramp-up. The shorter ramp up would be necessary if a mandate for electrification were put into effect.

These assumptions lead to about 250 residential electrifications and about 30 small commercial electrifications per year after the ramp up in the AGT Project solution, and nearly 700 residential and 100 small commercial electrifications per year, in the No Infrastructure solution. Compare that to approximately 70 to 75 residential heat pumps – and 0 commercial heat pumps – installed per year on Aquidneck Island through National Grid's electric EE programs in 2018 and 2019 (using statewide data scaled for Aquidneck). Note that all of this information is only for gas-to-electric conversions; if there were a local law, there would likely be just as many fuel oil customers switching to electric heat as well.

In the No Infrastructure solution, the cumulative number of heat pump installations by 2034-35 is ~9,300 residential customers (~80% of current residential heating customers in 2020, and ~67% of forecasted residential heating customers in 2035) and ~1,300 small commercial customers (~80% of current small commercial customers in 2020,and ~66% of forecasted small commercial customers in 2035).

Savings

The heat pumps were assumed to be cold climate in order to have full impact on the design day. The heat pump technology assumptions are shown in Table A-18 below.

Table A-18: Summary Electrification Technology and Cost Assumptions

Customer Segment	Electrification Measure	Annual Electric Savings (kWh)	Annual Gas Savings (Dth)
Residential	DMSHP (from gas-fired residential boiler + A/C blend)	-7,500	81
	CHP (from gas-fired residential furnace + central A/C)	-6,000	81
Small Commercial	DMSHP (from gas-fired commercial boiler + A/C blend)	-19,500	322
	CHP (from gas-fired residential furnace + A/C blend)	-22,750	322

Of the current natural gas customers converting to electric heating, 50% were assumed to keep 10% of their pre-electrification design day consumption. This remaining consumption was assumed to be from non-heating end uses like cooking that may not be electrified along with the heating. Note that the assumed pre-electrification design day consumption that's being saved is the average post-EE, which implicitly assumes that choosing to participate in EE and choosing to electrify are statistically independent choices.

Costs

Electrifying such a high number of gas HVAC replacements will generally require an incentive higher than the incremental cost of the heat pump. That is because even with the relatively high efficiency of heat pumps, current energy prices mean that the cost of heating with natural gas is less expensive than the cost of heating with electricity. The incentive therefore also must cover the increased cost of operation for the customer.

The following table provides the assumed incremental cost and net bill savings in 2020, which informed the value of the incentive. Note that the net bill savings are a combination of increased electric consumption for heating and reduced gas consumption for heating, plus electric savings from using the more efficient heat pump for cooling in the summer given the ratio of customers that previously had less-efficient summer cooling.

Table A-19: Summary of technology assumptions used in the model

Customer Segment	Electrification Measure	Incremental Cost ($)	Net Bill Savings ($/yr)*
Residential	DMSHP (from gas-fired residential boiler + A/C blend)	$8,900	-$300
	CHP (from gas-fired residential furnace + central A/C)	$13,000	-$15
Small Commercial	DMSHP (from gas-fired commercial boiler + A/C blend)	$9,700	$550
	CHP (from gas-fired residential furnace + A/C blend)	$20,500	-$16

* Assumes effective energy rates of $0.20/kWh and $15.09/Dth for RH and $0.18/kWh and $12.52/Dth for COM customers

The listed incremental technology costs are assumed to stay constant in nominal terms (i.e., reduce by 2% per year to offset inflation) over the 15-year analysis period. The bill savings – and by extension the assumed incentive payment per electrification by install year – are assumed to increase in line with inflation over time. Forecasted rate escalation is highly uncertain and is further complicated by its interdependence with the rate of electrification. High levels of electrification may improve annual utilization of traditionally summer-peaking electric assets, potentially reducing electric rates. Since this would be a highly localized program, it was assumed that this affect would not materialize for Rhode Island during the analysis period.

It was determined that payback periods of 3-4 years and ~0 years would be necessary to achieve customer acceptance levels of 33% and 100%, respectively, for electrification in the AGT Project and No Infrastructure solutions. However, the participants' simple payback cannot be calculated in this case given the negative bill savings. Therefore, the upfront incentive was calculated as the total incentives that would have been paid if 99.9% of the incremental cost had been incentivized up-front and 20 years of ongoing incentives had been provided to offset bill savings enough to generate the desired payback period. In practice, this ended up generating incentives of 100% to 200% of the incremental cost of the heat pump. As noted above, these incentives are based on highly uncertain forecasts of incremental costs and customer bill savings. In practice, incentives for electrification would have to continually be reassessed and reset.

In addition to these incentive costs, administrative costs were added to the upfront incentive costs such that 20% of the total upfront cost per year was attributable to fixed annual costs like training and administration.

Summary

The key assumptions defining the savings and costs associated with an incremental electrification program are shown in Table A-20 below.

Table A-20: Summary of Incremental Electrification Assumptions

Parameter	Assumption	Source
HVAC Turnover	5%/yr	Assumed 20-yr average life of HVAC consistent with demand forecasts
Payback Acceptance	33% & 100%	Residential payback acceptance curves; for AGT Project solution and No Infrastructure solution, respectively.
Percent Partial G2E	50%	Assumed half of customers would keep non-heating equipment during switch
Percent UPC Savings for Partial G2E	90%	Residential design day consumption by end use
Administrative Cost Adder	20%	Assumption

Summary Investigation

Into the Aquidneck Island Gas Service Interruption of January 21, 2019

Investigation Report

State of Rhode Island
Division of Public
Utilities & Carriers

October 30, 2019

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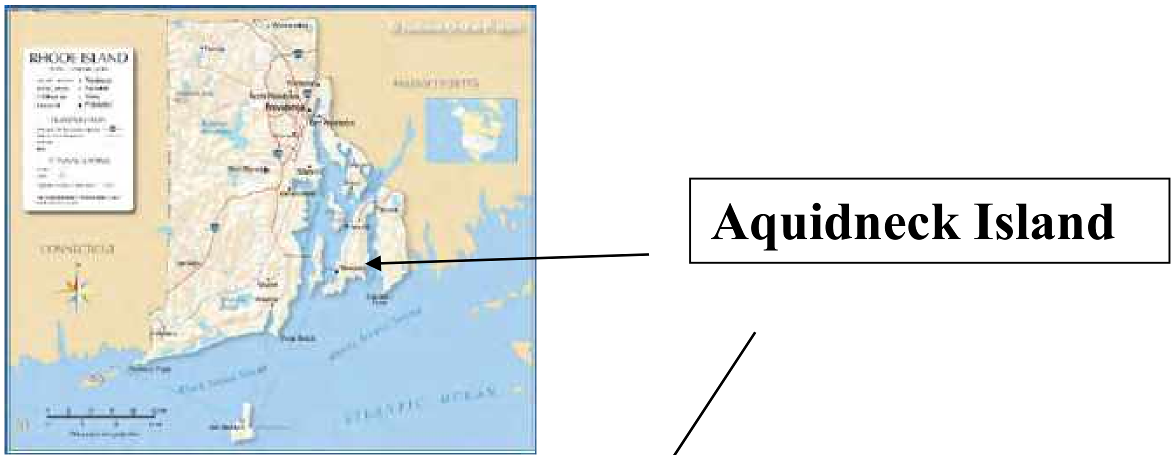

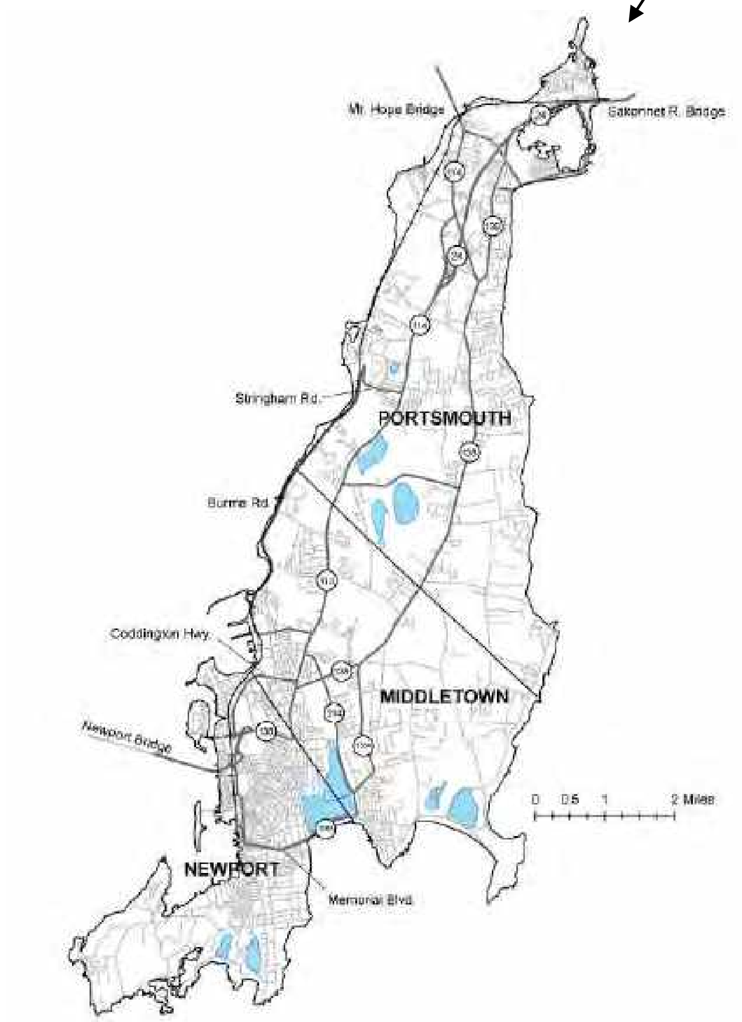

Figure 1. Aquidneck Island map.

Executive Summary

On January 21, 2019, at approximately 6:50 pm[1] The Narragansett Electric Company, Inc., (Narragansett Electric) known to its customers as National Grid,[2] shut down a significant portion of its natural gas distribution system in Newport and Middletown on Aquidneck Island, resulting in a gas service outage to 7,455 customers. The impact of the seven-day outage led Governor Gina M. Raimondo to declare a state of emergency in Newport County.[3]

On January 30, following restoration of gas service, the Division of Public Utilities and Carriers (Division) opened a "Summary Investigation" pursuant to §39-4-13 of Rhode Island General Laws to identify the causes of the outage and to assess any other matters related to gas capacity or supply constraints on Aquidneck Island. This Report provides the Division's investigation findings, identifies alleged violations of Rhode Island gas safety rules and describes a series of recommendations to enhance gas distribution reliability on Aquidneck Island and across Rhode Island.

Precipitating Factors in the Low-Pressure Condition on the Gas System

The gas service outage on Aquidneck Island was the result of a low-pressure condition on the "G-System" branch of the Algonquin pipeline, the portion of the interstate natural gas pipeline that serves Aquidneck Island and much of Rhode Island owned and operated by Enbridge, Inc. The low-pressure condition was the result of three separate precipitating factors that each contributed to cause the low-pressure condition. Those three precipitating factors that occurred on the morning of January 21st were as follows:

- Demand for natural gas was in excess of contractual limits by many of Algonquin's customers along the Algonquin G-System, driven by sudden low temperatures;
- The uninterruptible power system at the liquified natural gas storage and vaporization facility at Fields Point in Providence, owned and operated by National Grid LNG, failed, shutting down the vaporizers and causing a sudden and very large increase in demand for gas from the Algonquin pipeline into the Providence area;

[1] All times stated in this Report are Eastern Standard Time, unless otherwise specifically indicated.
[2] Narragansett Electric is a wholly owned subsidiary of National Grid USA. See infra page 11.
[3] Throughout the service outage first-responders from the National Guard, Rhode Island Emergency Management Agency, state and local law enforcement, and fire departments aided Aquidneck Island communities. The Division wishes to acknowledge their contribution to public safety.

demand that would otherwise have been met by vaporized LNG from the Fields Point facility;

- A valve located on the Algonquin pipeline at a meter station in Weymouth, Massachusetts operated by Enbridge malfunctioned. The malfunction stemmed from a programming error that caused the valve to repeatedly open and close restricting the flow of gas when the system operators attempted to inject more into the Algonquin pipeline that feeds gas into the G-System.

The Report, in concert with an accompanying report from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA), finds that each of these three precipitating factors needed to occur in order to produce the low-pressure condition that ultimately led to the gas service outage.

Had Algonquin programmed its valve in Weymouth correctly, modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment. As the provider of interstate gas transportation, Algonquin had a duty to program its meters and valves correctly to assure safe and reliable service to its customers. But, in this case, it failed to do so. Similarly, the National Grid LNG shutdown of its LNG vaporization facility, due to a failed uninterruptible power supply that caused the plant's vaporizers to fail, contributed to the low-pressure condition. According to PHMSA, National Grid LNG experienced an emergency shutdown in November 2018 due to a failed uninterruptible power supply which it did not adequately investigate or resolve. Had National Grid LNG taken steps to address the faulty uninterruptible power supply modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment.

<u>Forecasting and Planning Errors of Narragansett Electric</u>

Regardless of the cause of the low-pressure condition, the ability of Narragansett Electric to respond to the failures at the Weymouth meter station and the Providence LNG facility once they had occurred was significantly limited by its management of the gas distribution system over the previous several years. Narragansett Electric through its decisions created preconditions that significantly contributed to the outage. In particular:

- Narragansett Electric had deactivated its permanent LNG storage and vaporization facility located in Newport in 2010. As demand on the island grew year by year, the Company failed to forecast the need to redeploy LNG to address load growth. Similarly, Narragansett Electric did not deploy temporary LNG vaporization facilities at Portsmouth during the winter of 2018-2019. Narragansett Electric made these decisions based on erroneous forecasting assumptions.
- Narragansett Electric did not engage in contingency planning on its distribution system despite having experienced a similar low-pressure condition on March 7, 2014.

As important as the precipitating factors were, the planning and forecasting errors of Narragansett Electric made the distribution system vulnerable to the effects of a low-pressure condition and a widespread service outage. Based on almost a decade of gas system operational decisions, Narragansett Electric concluded that it did not need to have LNG vaporization capability on Aquidneck Island. Had Narragansett Electric installed backup LNG vaporization, the gas distribution pressure could have survived the low-pressure condition without an outage by supplementing Aquidneck Island with vaporized LNG. Similar to the duty of Algonquin, Narragansett Electric had a duty to forecast accurately, to plan appropriately, and to deploy assets to address foreseeable contingencies.

Additional System Vulnerabilities

In addition to the specific causes of the January 21 outage, the Report identifies a series of vulnerabilities that did not contribute to the outage of last winter but present a future vulnerability to the gas system which Narragansett Electric should address. In particular:

- Narragansett Electric lacked a mapping and tracking process to manage outage reports;
- Narragansett Electric did not have a viable plan to sectionalize its gas system as an emergency preparedness measure;
- The National Grid organization manages Narragansett Electric's gas business through an organizational structure that does not have a Rhode Island-based senior executive to direct gas operations;

- Narragansett Electric and National Grid LNG did not conduct an appropriate after-action review and did not provide a report of its review to the Division or to federal regulators. In fact, the Company did not inform the Division of the failure of the vaporizers at the Providence LNG facility until 39 days after the event.

Recommendation for Denial of Cost Recovery by Narragansett Electric

Based on the findings of the Report, the Division has identified sufficient grounds for it to oppose recovery of over $25 million in costs incurred by Narragansett Electric. The Division will recommend that the shareholders of Narragansett Electric and Enbridge, not Rhode Island's gas customers, bear the costs of the gas outage and restoration. The final determination of any cost recovery, should Narragansett Electric seek it, would be made by the Public Utilities Commission. The Report takes no position on how these costs should be allocated between Enbridge and National Grid through civil litigation. In addition, the Division will issue a Notice of Probable Violation to Narragansett Electric for a violation of Division gas regulations pertaining to a failure to notify the Division of the shutdown at the Providence LNG facility on January 21, 2019.

Recommendations for Gas System Improvements

(1) Improve gas long-range Planning;

(2) Deploy LNG facilities on Aquidneck Island;

(3) Evaluate reinforcement of the Algonquin lateral pipeline serving Portsmouth;

(4) Implement demand response initiatives on Aquidneck Island;

(5) Conduct scenario-based contingency and emergency response planning;

(6) Evaluate the feasibility of sectionalized gas districts in Newport;

(7) Establish a process for emergency mobilization of LNG;

(8) Create an outage mapping and tracking process;

(9) Conduct an after-action review process;

(10) Improve communications between Narragansett Electric and Algonquin;

(11) Appoint a Vice President to supervise the gas business for Rhode Island:

(12) Implement the recommendations of the PHMSA report on this incident.

Conclusions

Over 250,000 Rhode Island families and businesses depend on natural gas to heat and operate the buildings in which they work, live and sleep. For most of these customers, natural gas is their only fuel option. The recommendations of this Report will enhance the reliability of winter heat for gas customers and will ensure that the customers of Narragansett Electric and Enbridge are not financially responsible for the outage.

Investigation Process Note

This Report is the final product of an investigation undertaken by the Rhode Island Division of Public Utilities and Carriers (Division), pursuant to its authority under §39-4-13 of the Rhode Island General Laws.[4] The statute authorizes the Division to "summarily investigate" matters prescribed in that section of the law, including issues relating to public safety, the quality or adequacy of service of any public utility, or "any matter relating to a public utility."

On January 30, 2019, then Deputy Administrator Kevin Lynch notified The Narragansett Electric Company, Inc. (Narragansett Electric) that the Division had opened an investigation of the gas service interruption on Aquidneck Island. Mr. Lynch, who became Interim Administrator of the Division in February 2019, assigned Jonathan Schrag, Deputy Administrator, the role of Investigative Lead and John Spirito, Chief Legal Officer, the role of Hearing Officer and arbiter of any procedural legal issues. Consistent with precedent in Division investigations, neither John Spirito nor Interim Administrator Lynch participated in any substantive part of the investigation, remaining in reserve to decide any matter, violation, or request for regulatory order the investigation might produce, pursuant to §39-4-14 of Rhode Island General Laws.[5] Shortly before the completion of this Report, Mr. Lynch left the Division to pursue another government position and Linda George was appointed Interim Administrator. Ms. George similarly remained separate from the investigation to preserve her impartiality.

To perform the investigation, Deputy Administrator Schrag assembled an investigation team. The team included: Ron Gerwatowski, Senior Regulatory Advisor to the Division,[6] as the lead coordinator; Leo Wold, Deputy Chief of Legal Services for the Division; and Alberico Mancini, Deputy Chief Public Utility Accountant for the Division. In addition, pursuant to §39-1-19 the Division relied on the Office of the Attorney General Public Utilities Regulatory Unit to represent the Division. For gas technical expertise, the Division hired two expert consultants on natural gas matters: Greg Lander, President of Skipping Stone, LLC who provided expertise relating to interstate pipeline matters; and Rod Walker, CEO/President of Rod Walker &

[4] See: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-4/39-4-13.HTM
[5] § 39-4-14 states: "If, after making a summary investigation, the division becomes satisfied that sufficient grounds exist to warrant a formal hearing being ordered as to the matters so investigated, it shall furnish to the public utility interested, a statement notifying the public utility of the matters under investigation. Ten (10) days after the notice has been given, the division may proceed to set a time and place for a hearing and investigation."
[6] Mr. Gerwatowski works for the Division through a consultancy contract.

Associates, who provided expertise on gas distribution system operations. The Division relied upon the advice and expertise of these natural gas experts for the technical conclusions in this Report.

The Division conducted its investigation through multiple rounds of written requests for information and data from Narragansett Electric, as well as interviews with Narragansett Electric employees. The Division received over 200 written responses to questions and many files containing operational data. In total, the Division reviewed over 5,000 pages of information from the Company. The Division also held five interviews with Narragansett Electric employees to orally examine designated topics related to the outage. At these meetings, the employees had an opportunity to present their views.

Throughout its investigation, the Division worked in close cooperation with the Pipeline and Hazardous Materials Safety Administration (PHMSA) – the agency of the U.S. Department of Transportation that oversees pipeline and liquified natural gas (LNG) safety. PHMSA has direct regulatory authority over interstate pipelines, including the operations of Enbridge, the owner of Algonquin Gas Transmission, LLC that operates an interstate pipeline providing service to Rhode Island. PHMSA also has direct authority over gas safety and maintenance matters, including the operations of National Grid LNG, LLC, a distinct, federally regulated and wholly-owned subsidiary of National Grid USA, which owns the LNG storage facility located at Fields Point in Providence.[7] The Division relied on PHMSA for information that PHMSA obtained directly from Enbridge and National Grid LNG, LLC. The Division and PHMSA investigation teams collaborated through regular telephone conferences and a two-day in-person meeting in Rhode Island. PHMSA will issue its own report consistent with the scope of its regulatory authority. Throughout the investigation PHMSA and the Division exchanged information and the reports of the two agencies are intended to be read in concert with each other.

[7] There is a provision in Title 39 of Rhode Island General Laws which states that there is a statutory presumption of state jurisdiction over the use of any liquified natural gas within the borders of the state. See §39-1-2.2. However, the provision lacks specificity. In contrast, the owner of the Providence LNG facility is regulated directly by federal authorities under laws and regulations that are specific and wide in scope. The existence of this federal authority raises technical legal questions about the doctrine of federal preemption which holds that if there is a conflict between state and federal authority, the federal rule prevails. See *Verizon New England Inc. v. Rhode Public Utilities Commission*, 822 A.2d 187, 192 (R.I. Sup. Ct., 2003) ("The Supremacy Clause of the United States Constitution, Article VI, clause 2, preempts or invalidates state law that interferes or conflicts with federal law."). The Division does not concede the applicability of the preemption rule here and reserves all of its rights.

The Hearing Officer issued a protective order that set forth the confidentiality parameters of the investigation, consistent with Rhode Island General Laws §38-2, the Access to Public Records Act (APRA).[8] The Division's investigation and all information accumulated during the pendency of the investigation were treated confidentially, in accordance with the provisions of APRA.[9] With the completion of the summary investigation through the issuance of this Report, the records specifically relied upon for the conclusions in this Report are public, unless there is an APRA exemption that applies. For the convenience of the public, this Report includes an Appendix that contains copies of the key records relied upon, as cited in the footnotes to the Report.[10]

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[8] See http://webserver.rilin.state.ri.us/Statutes/TITLE38/38-2/INDEX.HTM A copy of the protective order is provided at the end of the Appendix to this Report.

[9] All materials during the investigation are exempted from public disclosure as "investigatory records" pursuant to §38-2-2(4)(P). The applicable exemption is defined as: "All investigatory records of public bodies, with the exception of law enforcement agencies, pertaining to possible violations of statute, rule, or regulation other than records of final actions taken, provided that all records prior to formal notification of violations or noncompliance shall not be deemed to be public."

[10] As indicated in the Appendix, there are a limited number of records or sections of records that remain exempt from public disclosure pursuant to other APRA exemptions, such as critical energy infrastructure information, personal or customer-specific information, and materials claimed as proprietary by Narragansett Electric.

National Grid Group Corporate Naming Structure

In Rhode Island, the utility providing gas service is recognized under the corporate name and logo of "National Grid." Yet, as a legal and corporate matter, the actual corporate entity regulated by the Public Utilities Commission and the Division is "The Narragansett Electric Company" (Narragansett Electric) which does business under the brand name of "National Grid." Narragansett Electric is a subsidiary in the chain of corporate entities that begins with the London-based parent company, "National Grid plc."

Because numerous subsidiaries under "National Grid plc" do business under the brand name of "National Grid," it can cause confusion when more than one company in the National Grid corporate family is involved in a single matter. For that reason, this Report will use the formal legal name of the Rhode Island entity The Narragansett Electric Company, Inc. (Narragansett Electric) when describing most of the events. Throughout this Report, the terms "Narragansett Electric" and "the Company" refer to the Rhode Island public utility regulated by the Division and the Commission. When the Report describes other specific National Grid corporate entities, it will use their formal names to avoid confusion.[11]

Below is a simplified corporate organization chart which is designed to illustrate the structure. The chart is not comprehensive and leaves out numerous separate corporations. For example, there are several separate regulated companies in the states of Massachusetts and New York, as well as numerous other entities in Europe and elsewhere. For purposes of the chart, they are bundled in one box each for each state and one box for the other international companies. Numerous other entities are not shown. While the chart is simplified, it is designed to illustrate the structure starting with the London-based parent and cascading down to the companies in the United States. As the chart also indicates, there are both regulated and unregulated entities in the corporate family. This distinction is important for reasons that are addressed in subsequent sections of the Report. The chart is provided here to assist the reader.[12]

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[11] While this Report attempts to draw the corporate distinctions, the responses to the Division's data requests from Narragansett Electric do not always do the same. Many of the written responses tend to use the term "Company" and "National Grid" quite liberally, without clear distinctions between the separate entities.
[12] More information about the numerous entities are available at the following National Grid plc website: https://investors.nationalgrid.com/debt-investors/group-structure

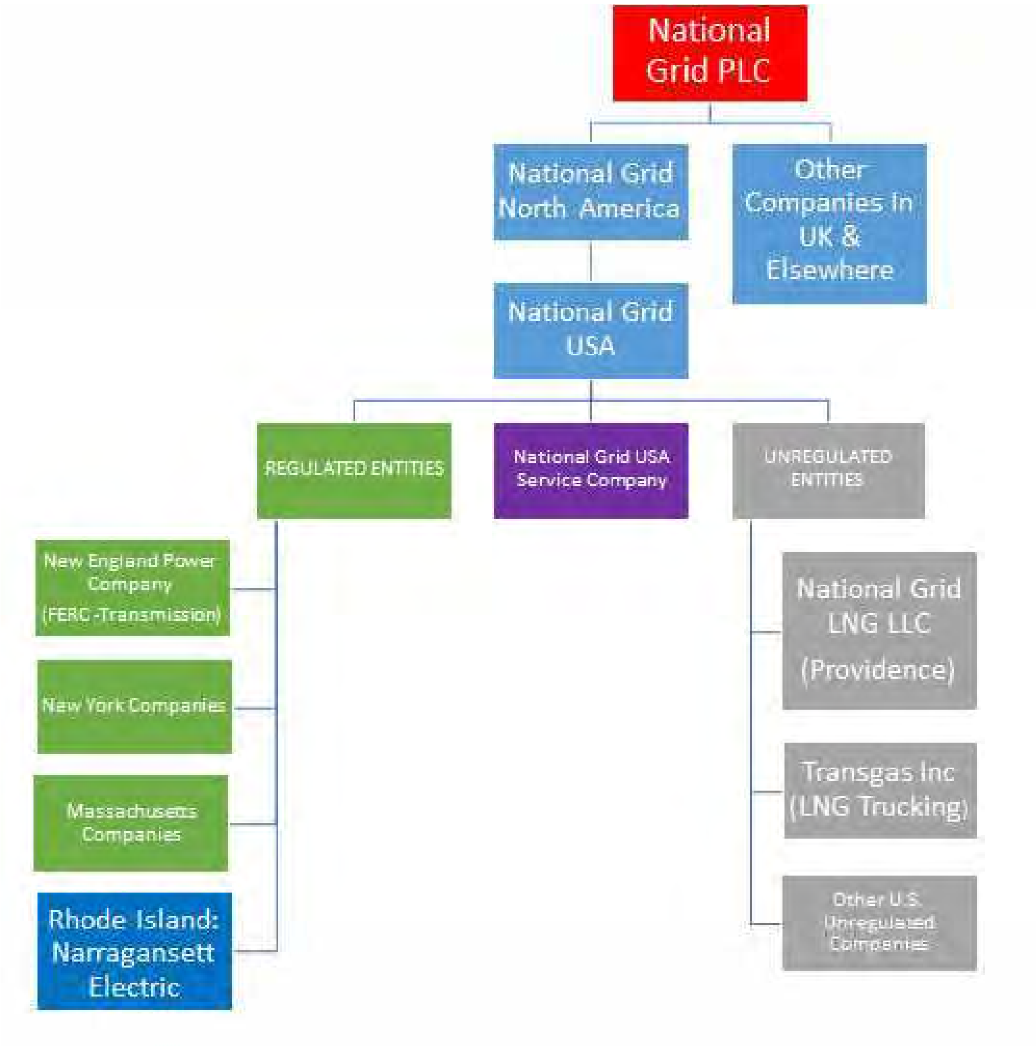

Figure 5: Simplified Illustration of National Grid Corporate Structure – from U.K Parent down to U.S. entities.

Section 1.0: The Natural Gas Systems

The events of January 21, 2019 occurred within a complex set of natural gas pipeline systems serving Rhode Island. This section provides information about the structure of these pipeline systems as they affected the events of January 21, 2019.

1.1 The Interstate Gas Systems Serving Rhode Island

The general configuration of the natural gas pipeline systems that serve Rhode Island consist of two types of systems. One is the interstate pipeline system that transports gas across state lines and the other is the local gas distribution system confined to Rhode Island that is owned by Narragansett Electric.

The map in Figure 2 shows the two interstate pipelines that deliver natural gas into Rhode Island. One is the Tennessee Gas Pipeline system owned by Kinder Morgan, shown in blue. The other is the Algonquin Gas Transmission system (Algonquin) owned by Enbridge LLC (Enbridge), shown in orange.

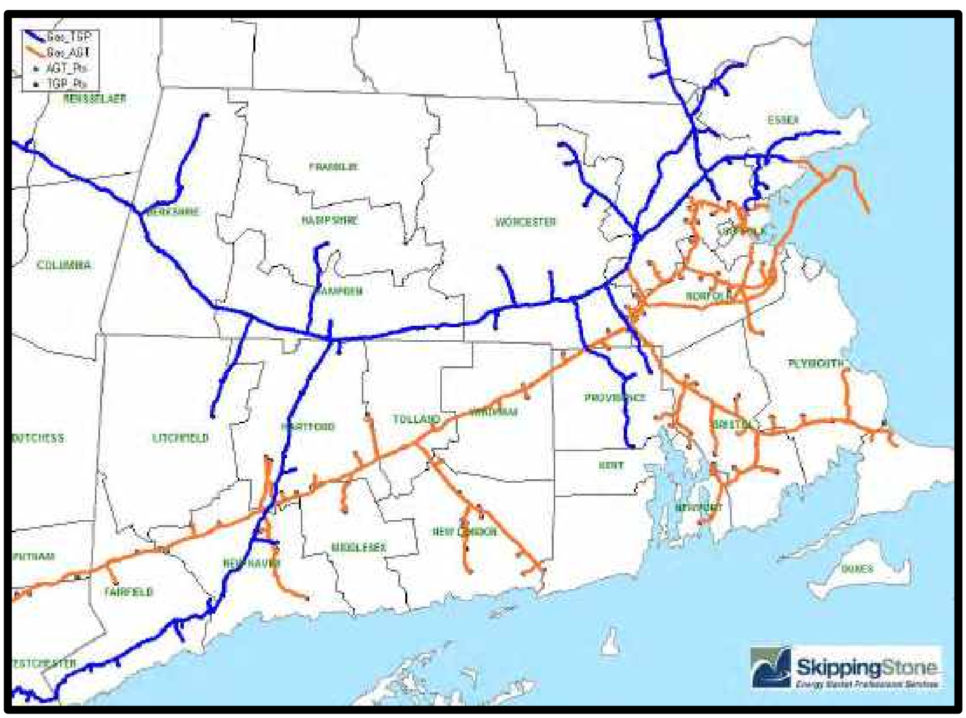

Figure 2. Map showing the Algonquin pipeline (orange) and Tennessee Gas Pipeline (blue)

Each of the interstate pipelines delivers gas to Local Distribution Companies ("LDCs") and direct-connected end-users[13] at receipt points known as "take stations."[14] The take stations are both the physical and jurisdictional demarcations between the interstate pipelines, which are regulated by federal authorities including PHMSA and the Federal Energy Regulatory Commission (FERC), and the intrastate gas distribution system that is regulated by the State of Rhode Island through the Division of Public Utilities and Carriers and the Public Utilities Commission.

The Algonquin Gas Transmission ("Algonquin") system, owned by Enbridge delivers gas to Aquidneck Island and was the interstate pipeline system most directly involved in the outage of January 21. The Algonquin mainline begins with an interconnection at the Texas Eastern Transmission System in New Jersey,[15] runs through New York and Connecticut, across the northwest tip of Rhode Island, and into Massachusetts, ultimately interconnecting with the Maritimes & Northeast Pipeline[16] north of Boston.

One of the main branches of the Algonquin system in New England, referred to as the G-System, branches south from the mainline near Mendon, Massachusetts to provide gas service to southeastern Massachusetts and Rhode Island.[17] The G-System delivers gas to Providence and eventually onward to Aquidneck Island. The G-System is the subsystem of Algonquin on which the low-pressure condition causing the outage on Aquidneck Island occurred.

Typically, most of the natural gas delivered into Rhode Island on the Algonquin system follows a path from southwest to northeast. But, the Algonquin mainline can be supplemented with deliveries from the north to the south through a branch that connects to the Maritimes & Northeast pipeline which extends from Canada to the Boston area. This branch of the Algonquin system is referred to as the I-System. In the middle of the I-System is a metering and valve station at Weymouth, Massachusetts which controls the flow of gas from northern supply areas in Canada as well as, when present, off-shore LNG tankers capable of vaporizing LNG into the I-System[18].

[13] In New England, direct-connected end-users are primarily natural gas fired power plants that generate electricity.
[14] In industry parlance, "take stations" also are referred to as "gate stations" and "M&R stations." In this Report we will use the term take station. From the pipeline's perspective a take station is a delivery point; while from the gas distribution company's perspective it is a receipt point.
[15] The Algonquin system also receives gas from other interstate pipelines, including Transcontinental Gas Pipeline, Columbia Gas Transmission, Tennessee Gas Pipeline, Millennium Pipeline, and Iroquois Gas Transmission.
[16] Both of the Texas Eastern Transmission and Maritimes and Northeast pipelines are also owned and operated by Enbridge. In this report, these two lines will be referred to by their operating names and not as Enbridge.
[17] There are various subsystems off the Algonquin mainline system that are identified with letters.
[18] On January 21, 2019 there was an LNG Tanker that was vaporizing LNG into the I-System.

This Weymouth metering station was one of the precipitating factors of the low-pressure condition on January 21, 2019.

For reference, the map in Figure 3 shows the Algonquin system and marks the location of the mainline, G-System, the I-System, Aquidneck Island and the Weymouth meter station.

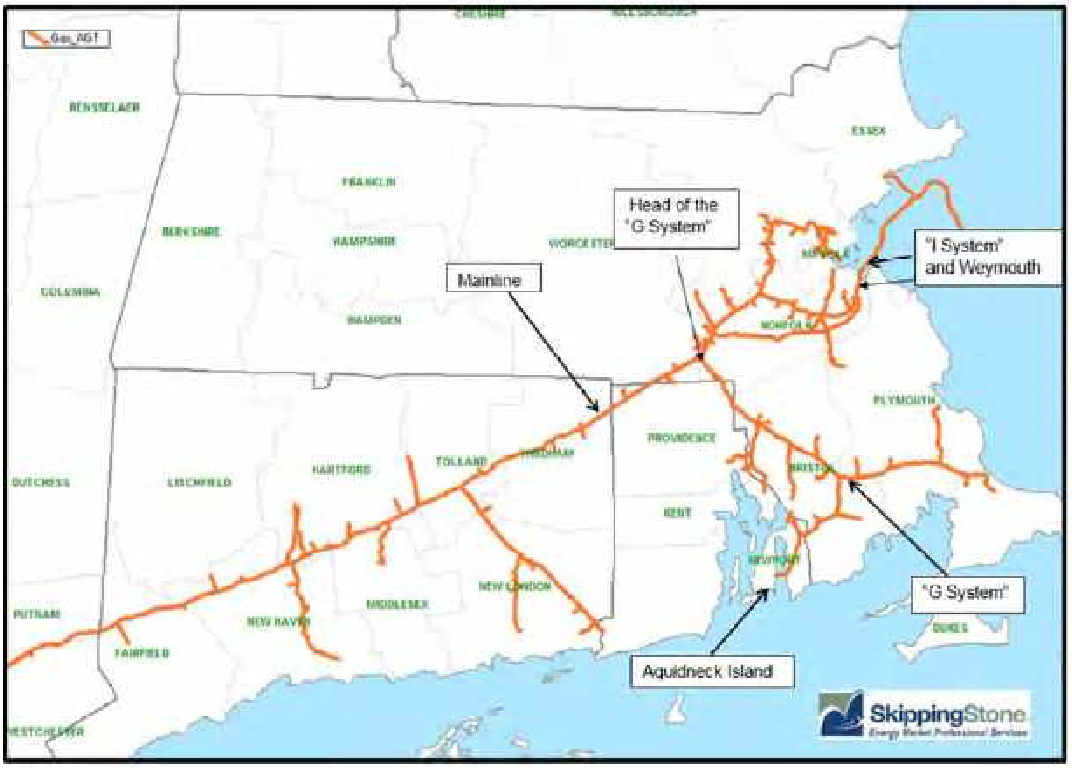

Figure 3: Map identifying relevant areas on Algonquin Transmission relating to the events of January 21, 2019.

Narragansett Electric has ten take stations at which it receives deliveries for firm customers from the Algonquin system.[19] Eight of the take stations are off the G-System – three take stations in the Providence area, and one each in Cumberland, Barrington, Warren, Tiverton, and Portsmouth.[20]

[19] "Firm customers" are defined as those whose service may not normally be interrupted and generally include most residential and commercial customers. In contrast, "interruptible customers" pay a lower price for gas service and are often interrupted during times of peak demand. These include power generators and other industrial customers who have dual fuel capability for heating or other uses.

[20] The other receipt points are in Westerly and Burrillville. There are other receipt points off the Algonquin system that serve generators in Rhode Island that are not related to gas distribution service provided by Narragansett Electric. Exhibit 1 to the Company's Operational Balancing Agreement with Algonquin identifies all the Narragansett Electric receipt points. Attachment DIV 4-1, page 5. A listing of all the Narragansett Electric contracts can be found on the Algonquin website at: https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG

Aquidneck Island is located at the downstream end of the Algonquin G-System, leaving it in a vulnerable position with respect to unusual gas pressure conditions that might occur on the Algonquin system. All of Aquidneck Island depends exclusively on the G-System take station at Portsmouth for natural gas service. There are no other connections from Algonquin or any other interstate pipeline system to Aquidneck Island. The Portsmouth take station is at the "downstream" end of the G-System, with many customers located between it and the head of the G-System. As a result, a low-pressure condition on the G-System will have a particularly significant impact on the pressure of the Portsmouth take station. In addition, there is a single six-inch diameter pipe that delivers gas into the Portsmouth Station to serve all of Aquidneck Island, a smaller diameter connection to the mainline than many other locations on the Algonquin system.

1.2 Federal and State Regulatory Authority

Under the federal Natural Gas Act, regulatory oversight over natural gas service is divided between federal and state authorities. PHMSA and FERC have authority over the interstate pipeline systems, including Algonquin. The Division has regulatory authority over regulated public utilities doing business in the state, but the Division has no regulatory authority over Algonquin or its parent company, Enbridge. While the Division has no regulatory authority over Algonquin, the Division coordinated with PHMSA in the investigation. PHMSA provided important information that allowed the Division to understand the sequence of events that resulted in the low-pressure condition on January 21, 2019. This complementary regulatory framework highlights the need for communication among Narragansett Electric, National Grid LNG and Algonquin to ensure reliability.

1.3 The Physical Attributes of Natural Gas Delivery

The events of January 21, 2019 reflected important physical characteristics of natural gas transportation. Unlike the electric system, where the flow of electricity is nearly instantaneous across long distances, gas travels relatively slowly, typically between 10 and 30 miles per hour. As a result, gas pressure and flow anomalies that occur on gas delivery systems do not typically result in instantaneous effects across long distances.

Pressure on the interstate pipeline systems needs to be relatively high to move large volumes of gas. Once the gas reaches a take station, the gas pressure is reduced in order to flow the gas into the distribution system as it is safely delivered to consumers. Gas service reliability is at risk if gas pressure drops below the level necessary to push the needed quantities to the gas load.[21] Gas pressure and gas flows, in this regard, are critical at every stage of the transportation process.

Along a pipeline, natural gas flows from high pressure supply areas to lower pressure demand areas. If there is a pipeline pushing natural gas in one direction and there are consumers taking gas all along the pipeline, gas will go to the demand that it first encounters. If there is not enough gas to meet the demand all the way to the end of the pipe, then consumers closest to the higher-pressure supply "upstream" will draw first. As less and less gas is available traveling downstream, the demand for gas will cause the system to try to pull more gas than is available. This, in turn, will cause the pressure on the overall system to drop. The only options to retain gas pressure in this scenario are either to inject more gas into the system (upstream or at the location of consumption) or to shut off demand. A low-pressure condition can create the risk of a widespread loss of gas service to customers on the gas distribution system.

Natural gas pipeline transmission companies design their systems to assure that there is enough gas supply, flow and pressure on the coldest days of the year to assure that all contracted levels of service to take stations can be served simultaneously, all the way to the most downstream take stations. This means that each take station on the interstate system is assigned an hourly maximum of natural gas that should not be exceeded during the hours of highest demand. However, it is not always possible to control the precise amount of gas draw. For that reason, pipelines may allow some flexibility for gas to exceed the hourly maximums to some degree, as long as the reliability of the system is not affected. But the degree to which this is allowed may vary from interstate pipeline to interstate pipeline. Nevertheless, if all take station locations in a subsystem are taking their maximum hourly flow and there is an unusual condition that causes one or more take stations on the system to draw amounts significantly over their maximums, this can cause the pressure on the pipeline to drop, if the aggregate draw exceeds the capacity of the system. Pressure and flow were factors in the events that transpired on January 21, 2019.

[21] Here, gas load is the consumption by homes and businesses downstream of the take station.

1.4 The Low-Pressure Distribution System on Aquidneck Island

Aquidneck Island is vulnerable to low-pressure conditions that might occur on the Algonquin G-System based on its location at the end of the line. But there is another significant factor contributing to the outage that relates to the gas distribution system on Aquidneck Island itself. This system was acquired by Narragansett Electric in 2006 from Southern Union Gas Company, when Narragansett Electric purchased the gas distribution assets of Southern Union Gas Company and took over the gas distribution business. Responsibility for maintenance and planning of the gas distribution system on Aquidneck Island transferred to Narragansett Electric in 2006.

Because the detail of the system configuration may constitute confidential critical energy infrastructure information, the Report will not describe the configuration precisely. In general, the distribution system is not uniform but comprises a variety of pressures. This is not unusual in condensed areas within municipalities that had gas service installed long ago. Among these diverse systems on the island, there are bottlenecks along the pipes where the pipe size is not uniform from point to point. There is a lack of redundancy in some areas, with many areas of dead ends of distribution pipe. Sections also lack looping of service that would facilitate flow to stabilize pressures. This does not necessarily mean that the system is flawed, as these features are common to older systems that were initially constructed long ago.

Section 2.0 Operational Conditions in the Winter of 2018-2019

The pipeline systems in and around Rhode Island experienced operational conditions during the winter of 2018-2019 that affected the events of January 21, 2019.

2.1 The Role of Supplemental Liquified Natural Gas (LNG)

The supply of LNG is central to the events that occurred on January 21, 2019. This section will describe the use of LNG generally in the gas distribution industry, particularly in New England.

LNG is natural gas that has been liquified at very cold temperatures. When natural gas is liquified, its volume shrinks to 1/600th of its gaseous state. At this condensed volume, liquified natural gas can be stored in insulated tanks or transported by truck (as opposed to pipeline) to locations where it can be re-gasified (vaporized) and injected into a pipeline system (including distribution company pipelines). While LNG serves many purposes in the domestic and global gas markets, one of its most important purposes in New England is to supplement natural gas pipeline supplies during winter peak periods.[22] Once vaporized into a system, LNG can maintain system pressures in distant areas of the gas distribution system during peak hours of demand on the coldest days of the year. In this manner, well-planned LNG storage and vaporization facilities can effectively counteract a low-pressure condition especially with respect to constrained areas of a gas system.

LNG is stored in large permanent tanks at various locations in New England. In some areas, there are vaporization facilities that can directly inject vaporized LNG into the interstate pipeline system. There also are vaporization facilities that inject directly into the local distribution system. LNG can be transported by trucks where it is taken to facilities to be vaporized and injected into points in the gas distribution system to maintain system pressures where there are no permanent storage facilities. Gas distribution companies can use temporary vaporization facilities that can be mobilized to areas of the distribution system when the gas distribution company identifies a risk of inadequate supply or system pressure based on forecasted conditions. These temporary facilities can be moved to locations near the gas distribution system at relatively short notice when the need arises due to unusual conditions.

Although the use of vaporized LNG to maintain system pressures is critical, injection of vaporized LNG generally occurs infrequently. During normal winters, it is possible in some situations where no injections would be necessary at certain locations for the entire winter. In many instances, the injection of vaporized LNG for system pressure support may occur for only a limited number of hours per year. The availability of LNG to address the small number of hours during the year when it is needed can be a very cost-effective alternative to adding interstate pipeline capacity, especially when the capacity risk and cost relate to a small number of days and hours during a given winter.

[22] The use of LNG described in this Report to provide tactical support to the gas system is distinct from the large-scale international transportation of LNG from international supply areas that relies on LNG tanker ships and regasification facilities such as the one located at Everett, MA.

2.2 The Mothballed LNG Facility in Newport and Portable LNG Equipment

Narragansett Electric has a lease and operating agreement with the Navy for an LNG facility at the Newport Naval Base. The lease was assumed when Narragansett Electric purchased the gas distribution business from Southern Union in 2006. The purpose of the facility was to ensure LNG availability for vaporization to meet design day peak hourly demand for the Navy's facility on Aquidneck Island. As explained in later sections of this Report, a design day is the coldest day that the gas utility forecasts could occur, based on certain forecasting criteria. Since design days are very rare, the facilities were rarely used. Nevertheless, the LNG facilities were available to assure system reliability.

In 2010, the Company purchased 6,000 dekatherms/day of incremental pipeline capacity from Algonquin to serve its Rhode Island loads. At that time, the Company informed the Commission and the Division that it did not need the LNG facility at the Newport Naval Base and mothballed the operations.[23] As a consequence, the LNG facility on the Naval Base was not operational in January of 2019.[24] Neither the Division nor the Commission approved the decommissioning. The decommissioning was simply reported by the Company in response to a question. The decision was within the discretion of the Company in the management of its operations and neither the Division nor the Commission at that time had any reason to question the decision.

The Company also owned temporary LNG equipment for potential use at the Portsmouth take station.[25] The Company had plans to use the temporary LNG equipment during the summer of 2019 when Algonquin was scheduled to perform maintenance on its interstate pipeline (which would eliminate gas to Portsmouth for the maintenance period). The equipment, however, was in storage for the winter of 2018-19 because the Company did not believe the equipment would be needed for the winter.

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[23] Response provided in 2010 to data request "Division 1-3(c) in PUC docket 4199.

[24] For a discussion of the status as of 2018, see Company testimony in PUC Docket 4872, beginning on page 34 of 50, which can be found at: http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att(10-22-18).pdf

[25] See pages 36 & 37 of 50 of the testimony in Docket 4872, cited above.

2.3 National Grid's Providence LNG Facilities

In addition to the two other LNG facilities owned by Narragansett Electric in Rhode Island, there is a permanent LNG storage tank and associated vaporization facilities at Fields Point in Providence that is owned by Narragansett Electric's affiliate – National Grid LNG, LLC. This facility enjoys a regulatory and commercial status that is not intuitively consistent with its operational function. The National Grid LNG facility in Providence engages in transactions of interstate commerce and is therefore subject to federal regulation and not a regulatory part of the gas distribution system over which the Division or the PUC has jurisdiction. However, the facility is directly connected to the gas distribution system of Narragansett Electric and operates as a key reliability resource for the distribution system. The facility does not have any direct physical connection to the interstate Algonquin system.[26]

Specifically, the facility vaporizes volumes of natural gas scheduled by its customers, including Narragansett Electric. When the facility is vaporizing gas into the Narragansett Electric gas distribution system in Providence, Narragansett Electric does not need to take as much natural gas from the Algonquin system at the Company's Providence area take stations. Other customers purchase LNG from the facility through a "displacement" arrangement, whereby Narragansett Electric receives and uses the gas, and gas that otherwise would have been delivered to Narragansett Electric is then exchanged and taken by the customers at their locations in the interstate systems. In that sense, there is a "paper transaction" of a purchase and sale of gas. But, as a matter of actual gas flow, the LNG is injected into Narragansett Electric's system. Thus, the vaporized LNG essentially displaces natural gas that otherwise would need to be drawn off the Algonquin G-System by Narragansett Electric.[27]

Despite its separate corporate identity, National Grid LNG's internal structure also indicates that it is functionally a part of the Narragansett gas distribution system. The same group

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[26] A concise description of National Grid LNG, LLC and its facilities at Fields Point can be found in an order issued by the FERC in October of 2018, approving a liquefaction project for the facility. The order can be found at: https://www.ferc.gov/media/statements-speeches/glick/2018/10-17-18-glick-CP16-121-000.pdf?csrt=4290037376884803216

[27] Other customers purchase vaporized LNG from the facility through a "displacement" arrangement, whereby Narragansett Electric receives and uses the gas, and gas that otherwise would have been delivered to Narragansett Electric at other delivery points in the interstate systems is then exchanged and taken by the customer. In that sense, there is a "paper transaction" of a purchase and sale of gas. But the LNG is actually injected into Narragansett Electric's system.

of employees are assigned to supervise and manage all LNG operations in Rhode Island together, including the LNG facilities owned by Narragansett Electric in other locations. In this way, the Providence LNG facility is essentially managed and operated as a part of the group of LNG assets within Rhode Island, together with the facilities owned by Narragansett Electric, which likely brings operational synergies for the National Grid companies and related benefits to their customers.[28]

On a day as cold as January 21, 2019, the Providence LNG facility was performing an important function. The facility was not only supplying gas to the wholesale customers of National Grid LNG LLC, but it also was reducing the amount of natural gas supply that otherwise would have been drawn from other sources by Narragansett Electric, including additional supply off the Algonquin system. In other words, to the extent vaporized LNG was being injected into the Narragansett Electric natural gas distribution system in Providence, the gas draw in the Providence area on this very cold day would be reduced from the Algonquin G-System. Conversely, to the extent vaporized LNG was not injected, more gas would need to be drawn off the Algonquin system.[29] The Providence LNG was particularly important to the gas distribution system from an operational perspective as it maintained pressure, flow and line pack of the gas distribution system to manage the cold weather event of January 21, 2019. So, when the Providence LNG vaporizers shut down unexpectedly in the early morning hours of that day, a greater draw of gas was required from the G-System during the most crucial early morning peak hours of January 21, 2019. The shut-off that occurred at the Providence LNG facility on the morning of January 21, 2019 was the third precipitating cause of the low-pressure condition.

2.4 Cold Weather on January 21

January 21, 2019 was one of the coldest days experienced over the last decade. According to data reported on "newportriweather.com," the low temperature for Portsmouth on January 21 was 2 degrees Fahrenheit and the high was 12 degrees. According to the Company, there were only five days since January 2005 that were colder.

[28] National Grid's LNG group manages all operations of LNG facilities of National Grid across all National Grid operations in New York, Rhode Island, and Massachusetts.
[29] This is because the demand for gas in the Providence area did not change even as the source of supply to that demand did.

The temperature was not only cold on January 21, but the temperatures also changed rapidly over the course of the evening of January 20 into January 21.[30] For example, the weather report for T.F. Green Airport in Warwick shows that the temperature was above freezing in the early afternoon of January 20. By 5:00 pm on January 20, the temperature dropped to 25 degrees. By 9:51 pm, the temperature was only 18 degrees. Then by 1:51 am on January 21, the temperature had plummeted to 7 degrees. The temperature continued to drop to a low of 1 degree by 8:51 am.[31] Heavy rain was another weather factor. The rain hit the Warwick/Providence area on January 20 and was followed by the rapidly dropping temperatures in the early morning hours of January 21.[32]

Section 3.0 The Sequence of Events

This section of the Report provides a narrative of the key events of January 21, 2019, leading up to the Company's decision to curtail gas service in the low-pressure system in Newport and a portion of Middletown.[33]

3.1 Narrative of the Sequence of Events Up to Shut Off

At 3:45 am on the extremely cold morning of January 21, operators on the Algonquin G-System identified a significant demand increase.[34] The amount of natural gas delivered to Rhode Island was the highest in Rhode Island history.[35] According to Algonquin, hourly takes on the Algonquin system were higher on January 21, 2019 than any day in the previous 10-year period.[36] The previous high peak hourly rate for the Algonquin system in January 2015 was equivalent to 2. 9 billion cubic feet per day. On January 21, the peak hourly rate for the Algonquin system

[30] Attachment DIV 1-26S.
[31] Attachment DIV 1-26S.
[32] Division 1-26 Supplemental and Attachment DIV 1-26S.
[33] Both the Division and PHMSA have produced timelines of events. If the timelines are compared, there are two important distinctions to note. First, the Division uses Eastern Standard Time, to match the actual times experienced in Rhode Island. In contrast, PHMSA and Algonquin use Central Standard Time, which is often used in the interstate pipeline industry. Second, the Division cites pressure readings at various locations that were obtained from Narragansett Electric's information. In contrast, PHMSA used readings in many instances from data retrieved from Algonquin data. The pressure readings do not always match precisely for the approximate hours identified but are not material.
[34] Algonquin Summary provided to PHMSA, dated Feb. 1, 2019 (hereinafter "Algonquin Summary to PHMSA").
[35] Attachment DIV 1-7S.
[36] "Chronological Explanation of the Events of January 21, 2019" from Enbridge (hereinafter "Enbridge Chronology for the Division").

reached approximately the equivalent to 3.3 billion cubic feet per day.[37] On the G-System, the total actual hourly takes significantly exceeded contractually scheduled nominations beginning at 4:30 am (EST) and continuing until 9:30 am (EST). Beginning at 5:00 am (EST), actual hourly takes at the ten delivery points on the G System into Rhode Island averaged more than 33% above maximum hourly limits based on the scheduled quantities for that day.[38]

During the hours between 3:45 am and 4:45 am, the gas distribution system of Narragansett Electric in Rhode Island was operating normally.[39] According to the Company, the G-System supplying the Company's take stations had inlet pressures ranging between 639 pounds per square inch gauge (psig) in Providence to 495 psig in Portsmouth.[40] However, according to Algonquin, the actual hourly takes at the Providence area meters where Narragansett Electric receives gas in the Providence area began to exceed Narragansett Electric's nominations that had been made for the gas day due to the high peak demand.[41] According to Algonquin, other unspecified customers of Algonquin on the G-System also were taking supply in excess of nominations.[42]

During this time prior to 4:45 am, the vaporization facilities at the Providence LNG facility were operating normally to provide supplemental supply into the Providence area.[43] At 4:44 am, the pressure at Portsmouth was in normal range, at 477 psi.[44]

At 4:45 am, the LNG facility experienced an unscheduled automatic shutdown.[45] According to information from PHMSA, the shutdown was initiated when the facility's uninterruptible power supply system failed, causing a loss of power. When power was lost, a "boil off" valve closed, which prevented the system from restarting.[46] According to Narragansett Electric, the area had experienced heavy rain on January 20 which left standing water in the area of the LNG plant that later froze when the temperature dropped during the late evening hours and

[37] To calculate the equivalent daily rate, the hourly rate is multiplied by 24.
[38] Enbridge Chronology for the Division.
[39] Division 1-1.
[40] Division 1-1.
[41] Enbridge Chronology for the Division.
[42] Algonquin Response to PHMSA Item 38.
[43] NG LNG 2-1, page 2.
[44] Attachment DIV 4-4-1, page 58.
[45] Attachment NG LNG 2-1. National Grid control room described it as an "emergency shut down." Division 2-11
[46] Memo from National Grid to PHMSA, dated June 11, 2019.

early morning hours of January 21.[47] When the system could not restart, the fuel valves to three of the four vaporizers at the facility froze from ice buildup.[48]

There also were separate problems at the LNG facility with the burner management system and exhaust system. Vaporization records provided to the Division by the National Grid LNG affiliate show that the vaporizers began operating again briefly, but then shut down at 6:00 am and did not resume partial vaporization operations until sometime around 8:30 am.[49] Even after the facility resumed operations the unit continued to experience vaporization problems throughout the day.[50]

According to Algonquin and information provided to the Division by PHMSA, shortly after the Providence LNG facility experienced the first shutdown at 4:45 am, the hourly takes of natural gas at Narragansett Electric's take stations off the G-System increased dramatically.[51] According to Algonquin, actual hourly takes at the Providence area meters significantly exceeded scheduled nominations after 4:45 am. Algonquin's records indicate that the actual hourly takes at the combined ten delivery points serving Narragansett Electric reached as high as 54% *above* the maximum hourly limits for the hour beginning at 7:00 am.[52] Despite the increase in takes, neither Narragansett Electric nor National Grid LNG informed Algonquin of the shutdown of the facility when it occurred.[53]

As indicated, other Algonquin customers were already taking gas in excess of their scheduled nominations. Combined with the draw now occurring from the shutdown of the LNG facility, the demand on the Algonquin system was extreme.

According to information provided by PHMSA, within an hour after the Providence LNG facility experienced the shutdown, pressure at the head of the G-System began to drop.[54] While Algonquin was unaware of the LNG plant shutdown, it saw the significant increase in demand on the G-System. In response, around 7:20 am Algonquin initiated a remote system order to change

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47 See Division 1-26 Supplemental and Attachment DIV 1-26S.
48 NG LNG 2-1 and Memo from National Grid to PHMSA, dated June 11, 2019.
49 NG LNG 2-1.
50 See Attachment NG LNG 2-8-6, pp. 6-7.
51 Algonquin Summary to PHMSA; Algonquin Response to PHMSA, Item JH 50, p. 2. (This response JH 50 contains confidential modeling information provided to PHMSA.)
52 Enbridge Chronology for the Division.
53 Algonquin Response to PHMSA, Item 45.
54 Pressure data provided by PHMSA.

the gas flowing through its metering station in Weymouth.[55] This was done to increase the flow of gas from north to south on the mainline. However, the Remote Terminal Unit at the meter had been programmed incorrectly.[56] As a result, instead of the flow increasing, the meter controlling the flow began to cycle open and closed, restricting the flow of gas. According to PHMSA, flow should have increased from 550,000 dekatherms/day to 700,000 dekatherms/day. But instead, flow dropped to 150,000 dekatherms/day.[57] In turn, outlet pressure dropped from approximately 850 psi to approximately 450 psi.[58] As a result of the meter malfunction, the low-pressure condition on the "G-System" was exacerbated, instead of mitigated. According to Algonquin, when they were unable to resolve the issue remotely, a technician was sent to the meter location to address the issue, arriving shortly after 9:00 am.[59]

By 9:07am, Narragansett Electric began to experience a significant decrease in pressure at the Portsmouth take station. According to the Company's records, pressure had dropped from 477 psi that was recorded around 4:45 am to 174 psi.[60] By 10:00 am, the inlet pressures from Algonquin to the Portsmouth take station had fallen to 97.7 psig.[61]

At around 9:45 am, a representative from Algonquin's gas control called National Grid to report the valve malfunction. According to National Grid, the Algonquin representative apologized for the incident.[62]

By 9:55 am, National Grid began to direct its technicians and other personnel to Aquidneck Island to assist in the response to the emergency conditions.[63]

Shortly after receiving the call from Algonquin's control center, at 10:18 am, the manager of the National Grid control center who had just spoken with the Algonquin representative sent an email to his boss, the Director of the control center, describing the low-pressure event as it was unfolding. In pertinent part, the email stated the following:

[55] Enbridge Chronology for the Division.
[56] Algonquin Response to PHMSA, Item 2.
[57] Algonquin Response to PHMSA, Item 2.
[58] Psi information provided from PHMSA.
[59] Enbridge Summary for the Division.
[60] Attachment DIV 4-4-1, page 58.
[61] Division 1-1, page 2. At 97.7 psi, the inlet pressure was now 2.3 psi below the contractual minimum pressure specified in the capacity contract between Narragansett Electric and Algonquin.
[62] Division 1-1, page 2.
[63] Division 17-1.

> The loss of the LNG had an immediate impact to our distribution system, the 200-psi line quickly dropped out to 100 psi, and the 99-psi system began to sag off as well. We picked up flow at Crary St and the loss of LNG naturally picked up the flow at Wampanoaog Trail. This also had an immediate effect on the AGT G-System which supplies down to Portsmouth [sic] GS on Aquidneck Island. The inlet pressure to Portsmouth has collapsed from 459 psi at the time of the shutdown down to 90 psi. We have I&R standing by on the island top [sic] bypass reg stations if needed.
>
> Coupled with the plant shutdown was an issue that AGT was having up in Massachusetts that contributed to the G-System suffering. They had a frozen valve on the Hub Line (Maritimes NE) supply in Weymouth Ma. They have since bypassed this valve and pressures have recovered nicely in the Weymouth – Milton area of MA but will likely take several hours to show any relief on Cape Cod and Rhode Island which are fed from the G-System."[64]

Meanwhile, the Algonquin technician who had been dispatched to Weymouth by Algonquin around 9:00 am was able to obtain manual control of the valve at the Weymouth metering station and re-establish stable flow by 10:29 am in Weymouth.[65] But the low-pressure condition was already having a significant effect on Aquidneck Island.

According to the Company, the response team recognized the impact that the low pressure was having on the distribution system on the island at around 10:26 am. At that point, Narragansett Electric began a process to bypass gas regulators in Newport to increase the flow of gas into the low-pressure system.[66] By bypassing the regulators, the Company was attempting to compensate for the loss of pressure occurring across the gas distribution system. The Company then continued to manually open bypass valves at regulator stations at other locations on the island.[67]

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[64] Attachment DIV 4-4-1, page 39 and Division 2-2 Supplemental.
[65] Enbridge Chronology for the Division.
[66] Division 1-1, page 2.
[67] Division 1-1.

At 11:09 am, the Company began to receive phone calls from customers regarding lost gas service or poor pressure.[68] The Company's records show 11 calls received between 11:09 and noon. However, these figures were only from customers who called the Company. There is no data available to indicate how many customers were without gas service and simply had not called the Company about the issue. The Company's process was to have customer meter services technicians (CMS technicians) respond to the calls by visiting the premises to shut off the meters.[69] At this time, however, the Company had four CMS technician vehicles deployed on the island to respond to the incoming calls.[70]

By 11:30 am, the Company alerted its LNG Operations team of the situation. The Company did not have a process in place for the emergency deployment of LNG operations.[71] Nevertheless, the Company believed it might be able to mobilize portable LNG quickly enough to inject gas into the Aquidneck Island distribution system to increase supply and pressure.[72] The National Grid Director of LNG for Rhode Island then began to take steps to mobilize temporary portable LNG operations to the Portsmouth take station.[73] However, the various equipment and supplies necessary to mobilize the LNG vaporization operations were stored in different places. Portable containment equipment was in Cumberland and the portable LNG vaporizer equipment (owned by Narragansett Electric's Massachusetts affiliate) was in Leominster, Massachusetts. Arrangements also were needed to be made with contractors for site preparation and the transport of a required chemical (glycol) that was needed for operation of the facility.[74]

According to the Company, shortly after 8:35 am and continuing during the day, the Company and its affiliates also issued directives to increase LNG injections into the Algonquin system and local gas systems from other LNG facilities in Massachusetts and Rhode Island in an effort to reduce demand on the Algonquin G-System.[75] The Company also took steps to increase

[68] Attachment DIV 1-14. (This file includes confidential customer information which is not public.)
[69] Division 17-5.
[70] Division 17-12. The Company has no count of when actual technicians arrived on the island to respond to calls. Instead, the Company has used information available to determine how many CMS vehicles were deployed. See Attachment DIV 17-12-1, page 1 of 1. For that reason, the Division uses the vehicle count in the description of the sequence of events.
[71] Division 12-12. According to the Company, temporary LNG operations always were deployed based on a specified need well in advance of deployment and typically is installed over a 72-hour period.
[72] Division 12-13.
[73] Division 12-14.
[74] Division 6-3.
[75] Division 1-1.

natural gas flow into Rhode Island from the Tennessee Gas pipeline into Rhode Island, for the same purpose.[76]

According to Algonquin, at around 11:55 am, the Weymouth station was restored to normal operations.[77] By 12:06 pm, the Company made an operational decision to shut off service to a portion of the low-pressure system serving a small area of Middletown, curtailing service to over 360 customers.[78] According to the Company, by isolating the smaller district the Company hoped to maintain pressures to the higher-pressure system supplying gas to the larger integrated low-pressure district in Newport.[79] The Company did not make any attempt to sectionalize other areas of the low-pressure system in Newport. According to the Company, it was not possible as a practical matter because the low-pressure system was not designed for sectionalizing and did not have shut-off valves designed for sectionalizing districts.[80] By 12:15 pm, the Company had deployed ten CMS technician vehicles to Aquidneck Island to respond to customer calls.[81] By 12:22 pm, the inlet pressure at the Portsmouth take station fell to 36.4 psig, the lowest recorded pressure. As a result, the impact on the low-pressure system in Newport spread.[82]

At 12:00 pm, the manager of the portable LNG projects had received word from the Company's glycol transporter that the contractor would not be able to deliver any glycol to Portsmouth for operation of the vaporizer equipment because there were no vehicles prepared or available for transport.[83] As a result, the manager began reaching out to other glycol suppliers. Also, according to the Company, the contractor that the Company used for transporting vaporizer equipment did not have personnel immediately available to transport the vaporizer equipment because of the holiday.[84]

By 1:00 pm, the Company had now received over 150 phone calls from customers without gas service or poor pressure.[85] Field technicians were being dispatched in a centralized manner to

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76 Division 6-4.
77 Enbridge Chronology for the Division.
78 Division 1-1, page 3.
79 Division 1-1, page, 3.
80 Division 18-9.
81 Attachment DIV 17-12-1.
82 Division 1-1, page 3.
83 Division 12-14.
84 Division 12-26.
85 Attachment DIV 1-14.

visit locations that had reported gas outages, attempting to shut off the services at those locations.[86] As of 1:23 pm, there were 20 CMS technician vehicles deployed on the island.[87]

At 1:45 pm, matting needed to support the LNG vaporizing equipment at the Portsmouth take station arrived and crews began to install it on site.[88]

By 2:00 pm, the number of "no gas/low pressure" calls rose to 370 customers.[89] The Company now had twenty-seven CMS technician vehicles deployed on the island.[90] By approximately 2:30 pm (as estimated by the Company), the command team made a decision to decentralize the process of dispatching field technicians to customers without gas service and changed to a local dispatch operation.[91] In addition, at some unspecified point during the event, the Company began implementing procedures to identify the scope of the problem. While the command team was aware of no gas calls that were being received, the Company did not have real-time data linked to its system maps. Given the circumstances where all the specific outage locations were not known, the Company implemented a process to manually "inventory" the extent of the outages.[92] This outage inventory was literally a manual process requiring technicians to survey the area on foot, checking from regulator stations outward to the end points of the low-pressure system. This process did not identify all the outages, but the Company maintains that it gave the command team a sense that the effects were growing more widespread on the low-pressure system.[93]

While there also were sporadic outages in parts of the higher-pressure systems on Aquidneck Island, they were limited in number.[94] Given the situation, the Company was able to maintain adequate pressures in those distribution segments, due in part to the actions it was taking to bypass regulator stations that kept the flow of gas at manageable pressures in those segments.[95]

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[86] Division 18-8.
[87] Attachment DIV 17-12-1.
[88] Division 12-14.
[89] Attachment DIV 1-14.
[90] Attachment 17-12-1.
[91] Division 18-8.
[92] Interviews, July 18, 2019.
[93] Interviews, July 18, 2019.
[94] Outage map, Attachment DIV 1-4-2 (This map contains Confidential Energy Infrastructure Information and is not public.)
[95] Division 1-1.

By 3:00 pm, the total of "no gas/low pressure calls" rose 650. By 4:00 pm, the calls reached 965[96] and the number of CMS vehicles deployed to respond to the calls was increased to twenty-nine.[97]

At 4:00 pm, the portable containment equipment for the LNG vaporization operation arrived in Portsmouth.[98] But the rest of the equipment (including the vaporizers) had not yet arrived and the site was still not ready for operation.

By this time, pressures off the "G System" at the Portsmouth take station began to increase toward normal pressures.[99] But the conditions on the low-pressure distribution system remained unstable and presented a safety risk.[100]

At 4:05 pm, the Company's Gas Dispatch department provided the emergency response team with the actual list of "no gas" calls that had been received up to that point, which the engineers began to map around 4:30 pm.[101] According to the Company:

> The Company expected that areas of no gas calls would occur on the southern peripheries or end points and crews could isolate those segments and maintain supply to the core integrated district. At 4:30 p.m., Dispatch provided a list of no gas calls. Engineering then prepared a map of the outages. National Grid then overlaid that outage map on the entire integrated low-pressure system and immediately recognized that the outages spread across all segments, including the northern and central segments.[102]

[96] Attachment DIV 1-14.
[97] Attachment DIV 17-12-1.
[98] Division 12-14.
[99] Attachment DIV 4-4-1, page 58.
[100] Division 1-1, pages 4-5.
[101] Division 1-1, page 4. The Company maintains that Gas Dispatch was "in frequent communication" with the leadership team during the course of the day, but there is no indication that detailed data was made available until 4:00 pm. See Division 17-7.

[102] Division 1-1, page 4.

Around 5:15 pm, the Company learned that it would not be able to receive delivery of sand and spill containment supplies necessary for the LNG operations until later that evening.[103]

By 5:00 pm, the Company had deployed forty-two CMS technician vehicles to the island. The "no gas/low pressure" call count was 1,250, rising to 1,325 by 6:30 pm.[104] By this time, the inlet pressure at the Portsmouth take station had increased to 257 psig.[105] But the outages that had already occurred on the low-pressure system were widespread.

At 6:50 pm, the Company made the decision to shut down the entire low-pressure system in Newport to protect the health and safety of the customers and communities.[106] According to the Company, if gas flow was restored, it would create safety risks for any home and business who happened to be using pilot-driven gas equipment and the Company had no way of knowing how many homes and businesses within the low-pressure system used such equipment in these historic communities.[107] A sudden return of flow of gas into pilot-driven appliances that had lost gas and the pilot-light was extinguished could create significant safety risks for customers because gas would flow past unit pilot-lights and be subject to ignition. Shutting down service to the over 7,000 gas customers on the low-pressure system assured that the sudden return of gas pressure to homes and businesses that had experienced outages would not inadvertently create those safety risks that could result in personal injury or property damage.

At 7:00 pm, the contractor completed the installation of matting at the Portsmouth vaporization site, but the shutdown of the low-pressure system in Newport was already underway.[108] At 8:28 pm, the last regulator station serving the low-pressure system was shut off, completing the shutdown.[109]

At 8:30 pm, the first vaporizer arrived in Portsmouth from Leominster, Massachusetts, but since the low-pressure system was already curtailed, there was no reason to begin injecting vaporized LNG into the system.[110]

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[103] Division 12-14.
[104] Attachment DIV 1-14 and Attachment DIV 17-12-1.
[105] Attachment DIV 4-4-1, page 59.
[106] Division 1-1, page 4.
[107] Division 1-1, page 5.
[108] Division 12-14.
[109] Division 1-1, page 5.
[110] Division 12-14.

While the Company had been in continuous communication with the Division throughout the day, the Company never notified the Division that there had been a shut-down of the LNG facility in Providence that some employees believed had an impact on system pressures.

3.2 Timeline Related to the Sequence of Events

Below is an abbreviated timeline of the events from 3:45 am to 8:30 pm.

Table 1 – Timeline of Events on January 21

3:45 am – High Demand on Algonquin System, Portsmouth inlet psig at 495.
4:30 am – Providence LNG facility vaporizers operating normally; Portsmouth psig at 477.
4:45 am – Automatic shutdown occurs at Providence LNG facility; hourly takes off G System begin to increase.
7:00 am – Hourly takes at Narragansett Electric points on Algonquin are 54% above limits.
7:20 am – Enbridge initiates a remote system order to change flow on Algonquin system from north to south at Weymouth metering station. Instead of increasing flow, the meter controlling the flow begins cycling, restricting the flow of gas.
8:30 am – Providence LNG facility resumes vaporization, but still experiencing problems.
8:35 am – National Grid control room begins issuing directives for the Company and its Affiliates to inject LNG into the Algonquin system to reduce demand on the Algonquin system.
9:00 am – Enbridge unable to resolve issue remotely, sends technician to Weymouth station.
9:07 am – Significant decrease in pressure at Portsmouth: now at 177 psig (compared to 477).
9:45 am – Algonquin representative calls National Grid to report valve failure.

9:55 am – National Grid issues directive for technicians and personnel to report to Aquidneck Island.

10:00 am – Inlet pressure at Portsmouth falls to 97.7 psig.

10:18 am – National Grid control center manager sends email to upper management reporting on Providence LNG shutdown and Algonquin valve failure.

10:26 am – Due to pressure problems experienced on distribution system, National Grid begins bypassing regulator stations to increase flow to low-pressure systems.

10:29 am – Algonquin technician obtains manual control of valve in Weymouth to re-establish flows.

11:09 am – National Grid begins receiving calls from customer reporting no gas or low pressure (11 calls received between 11:09 and noon).

11:30 am – National Grid alerts its LNG operations team to mobilize portable LNG to Aquidneck Island.

11:55 am – Algonquin metering station in Weymouth restored to normal operations.

12:00 pm – National Grid's manager of LNG portable projects receives word that the Company's glycol transporter cannot deliver glycol as requested for operation of portable LNG facilities in Portsmouth.

12:06 pm – National Grid shuts off service to portion of low-pressure system in Middletown, curtailing service to over 360 customers to maintain higher pressures on the high-pressure systems.

12:22 pm – Inlet pressure at Portsmouth take station falls to lowest level of 36.4 psig.

1:00 pm – No gas/low pressure calls from customers has now risen to over 150 calls.

1:45 pm – Matting arrives in Portsmouth to support potential LNG operations.

2:00 pm – No gas/low pressure calls have risen to 370.

3:00 pm – No gas/low pressure calls have risen to 650.

4:00 pm –Portable containment equipment for LNG vaporization arrives in Portsmouth. No gas/low pressure calls have risen to 650. Pressures into Portsmouth take station returning to normal, but customers on the low-pressure portion of distribution system in Newport have already experienced a high number of outages.

4:05 pm – List of no gas/low pressure calls is provided by Gas Dispatch to command team.

4:30 pm – Engineers begin mapping the location of gas outages from calls. Mapping results eventually show widespread outages across Newport.

5:00 pm – No gas/low pressure calls at 1,250.

6:30 pm – No gas/low pressure calls at 1,325.

6:50 pm – National Grid makes decision to curtail service to entire low-pressure system in Newport for safety reasons.

8:28 pm – The last regulator station serving the low-pressure system is shut down.

8:30 pm – First portable LNG vaporizer arrives in Portsmouth. But system is already curtailed.

Section 4.0 The Precipitating Events

This section of the Report details the precipitating events that caused the low-pressure condition. The next section of the Report will then address the Company's pre-event planning processes and ultimate response to the low-pressure condition.

As reflected in the sequence of events, it was a low-pressure condition on the Algonquin "G System" that ultimately led to the gas service outage. In the course of its investigation, the Division, in coordination with PHMSA, sought to identify the factors that contributed to this low-pressure condition. The investigation reviewed the data and ultimately concluded that there were three significant contributing factors to the low-pressure condition, all three of which were necessary in order for the low-pressure condition to occur. Those three factors were:

(1) An unusually high demand on the "G System" from the extremely cold conditions that placed a strain on the system, driven in part by Algonquin customers on the "G System" drawing gas in excess of their previously specified nominations for that day.[111]
(2) The shutdown of the Providence LNG facilities that caused even higher overtakes on the G-System; and
(3) The malfunction of the Algonquin metering valve at the Weymouth metering station which had been programmed incorrectly by Enbridge during the fall of 2018.

Described chronologically, the high demand on the G-System during the morning of January 21 was already placing significant stress on the Algonquin system. With the high demand, the unexpected shutdown of the Providence LNG vaporization facilities created further instability on the Algonquin G-System.[112] More natural gas was drawn into the Providence area from the Algonquin system to replace the volumes that otherwise would have been met on that cold morning by the LNG facility, causing hourly takes off the G-System that far exceeded the nominations made by National Grid into the Providence area.[113]

In a memo provided to PHMSA from the National Grid affiliate operating the facility, the affiliate explained the cause of the plant shutdown:

[111] Enbridge did not identify the other customers who were drawing gas in excess of nominations. The Division notes from the public records published by Algonquin, however, that other utilities such as National Grid in Massachusetts, Eversource, and (to a lesser extent) New England Gas Company, typically schedule large quantities of gas on the coldest days.
[112] National Grid LNG Memo to PHMSA 6/11/19

[113] Algonquin response to PHMSA, Item JH 50 and other information provided by PHMSA (This response contains confidential modeling information).

> National Grid LNG, LLC ("NGLNG") has analyzed the issues experienced at the Providence LNG plant on January 21, 2019. NGLNG has determined that an automatic plant shutdown occurred because of an interruption in power supply on the automatic plant shutdown system. When that automatic plant shutdown occurred, the boil-off valve closed. The plant was unable to restart immediately because the relay on the boiloff value failed to reset. The weather conditions, which included rapidly dropping temperatures and freezing rain, caused the boil-off valve and the fuel valves to the vaporizers to quickly freeze closed. The plant operators were able to manually open the boil-off valve and thaw the fuel valves and restart the plant (the fuel valves continued in automatic as the compressor valve was still manual). Additionally, after the plant restarted vaporizing, operators identified problems with the burner management system on vaporizer 3 and the damper on vaporizer 2 that reduced the plant output.

According to PHMSA, National Grid LNG experienced an emergency shutdown in November 2018 due to a failed uninterruptible power supply which it did not adequately investigate or resolve.[114]

Based on the results of modeling performed by Enbridge which PHMSA provided to the Division, it does not appear that the shutdown of the LNG facility, by itself, could have caused enough instability to precipitate in the outage on Aquidneck Island, even when combined with the large draw in excess of nominations from other Algonquin customers on the G-System.[115] But the sequence did not end there.

As the gas flows off Algonquin increased dramatically, the pressures on the G-System were materially affected downstream. While Algonquin was not immediately aware of what occurred at the Providence LNG facility, the Enbridge control center identified the instability and took steps to mitigate the system problem by sending a signal to its Weymouth metering station to increase the flow of gas from north to south. But the valve malfunctioned and instead of increasing the

[114] PHMSA Accident Investigation Report, August 13, 2019. Page 11 and 24.
[115] Algonquin response to PHMSA, Item JH 50 (This response contains confidential modeling information).

flow, the gas flow decreased, exacerbating and extending the time of the low-pressure condition. The metering valve malfunction was caused by a programming error that had been made in September of 2018.[116] Enbridge described the error in technical terms:

> An incorrect meter factor . . . which converts pulses from the meter to a volumetric flow rate, was stored within the Remote Terminal Unit. The incorrect meter factor caused the system to significantly inflate the calculation of natural gas flow through the meter facility, causing two control valves to continue cycling until [the pressure regulator] was set to manual by the Technician.[117]

Had the meter factor been set correctly in September of 2018, the valve would have increased the flow of gas into the Algonquin system, instead of restricting the flow and exacerbating the problem.

The Division coordinated with PHMSA to request that Enbridge conduct a series of modeling exercises based on several counter-factual scenarios.[118] After receiving the modeled results, the Division compared the modeled inlet pressures under each scenario at the Portsmouth take station to the lowest inlet pressure modeled by National Grid at which the low-pressure system likely would have been sustained. In each of the scenarios, the inlet pressure at Portsmouth exceeded the pressure needed to sustain the distribution system.[119] Based on these modeled results, it appears that if the Algonquin valve in Weymouth had operated properly, it would have been enough to provide sufficient supplemental gas flow to mitigate the unstable condition on the G-

[116] According to PHMSA, Enbridge's programming logs indicate that the mechanism controlling the flow rate was adjusted in September of 2018. This appears to be the time the programming error was made.
[117] Algonquin Response to PHMSA Item 2.
[118] Algonquin response to PHMSA, Item JH 50. This response to PHMSA contains confidential modeling information. For that reason, the resulting modeled inlet pressures for each scenario have been redacted in the copy provided in the Appendix to this Report, consistent with the confidentiality designation that was included on the response when it was provided to PHMSA under the federal process.
[119] See Division 21-5 for a description of National Grid's modeled results. It is important to point out that the modeled pressures also exceeded the contractual minimum pressure for Portsmouth.

System caused by gas flows in excess of nominations, thus avoiding the curtailment that eventually occurred on the island.[120]

The Division did not independently validate the complex modeling analyses conducted by Enbridge.[121] However, the underlying assumptions for each scenario were identical and the information was provided by Enbridge to PHMSA as a part of a formal investigation. The scenario modeling performed by Enbridge of the Algonquin system indicates that no single event among the three, or any combination of two events by themselves, would have created a sufficient low-pressure condition in Portsmouth to force to the outage. Instead, the modeling indicates that the occurrence of all three factors was necessary – high demand, a malfunctioned valve, and a malfunctioned LNG facility – to create the low-pressure condition which forced Narragansett Electric to shut down the gas distribution system on Aquidneck Island.

While the Division references modeling performed by Enbridge, it is important to point out that Enbridge had complete control over the modeling and inputs. While the Division has no reason to question the modeling process, the assumptions used, and the results obtained, it is equally important to point out that substantive review of the Enbridge modeling was not within the Division's authority. For example, the Division also learned through PHMSA that there were other factors present on the Algonquin system. According to PHMSA, these appear to have been less likely to have materially contributed, but they were present nevertheless. Specifically, the Algonquin mainline (west of the G-System) experienced compressor problems which could have contributed to the instability that morning.[122] Finally, there is a question whether the "line pack" within the Algonquin system was less than optimal that morning.[123]

It is not the Division's role to assess degrees or percentages of responsibility from the convergence of events. This is something that may only be sorted out in future legal proceedings involving the various possible contributors to the event, as liability among the parties is disputed

[120] Further, a newspaper report quotes an Enbridge spokesperson stating: "This equipment malfunction and temporary supply restriction may have been a contributing factor to the low-pressure situation in combination with the high demand for gas and the unexpected loss of natural gas supply from the National Grid LNG facility." See https://www.newportri.com/news/20190301/enbridge-points-to-national-grid-other-sources-for-newport-gas-outage

[121] Even if the Division had access to the data, the Division estimates that the cost of hiring a qualified firm to reproduce the modeling could have ranged between $250,000 and $500,000.

[122] The information from PHMSA reflecting the details of the compressor problems were confidential.

[123] "Line pack" refers to gas intentionally built up in the pipeline system by the pipeline company prior to peak demand hours that can help compensate for fluctuations in gas demand during a given gas day.

in the courts. Rather, it is the Division's role to assess the planning, actions, and responses of Narragansett Electric that occurred before, during, and after the outage event on Aquidneck Island.

Additional analysis of the precipitating factors and modeling of their impacts may be found in the Investigation Report issued by PHMSA.

Section 5.0: Preconditions Contributing to the Outage

In addition to the precipitating factors that caused the low-pressure condition, there were a number of preconditions that resulted from the way that Narragansett Electric had managed the gas distribution system over the previous decade that made it significantly more difficult for the distribution system to sustain minimum necessary pressure in the event of a low-pressure event. This section details the two major preconditions: first, a lack of LNG vaporization on Aquidneck Island and second, a lack of contingency planning.

Section 5.1: Lack of LNG Vaporization Facilities on Aquidneck Island

As described earlier in this Report, Narragansett Electric has a lease and operating agreement with the Navy for an LNG facility at the Newport Naval Base on Aquidneck Island. The Company also had temporary equipment on hold for potential use at the Portsmouth take station on the Island when Algonquin was scheduled to perform system maintenance during the summer of 2019. However, the Company had mothballed the pre-existing LNG facility in Newport and did not foresee any need to have any temporary LNG facilities at the Portsmouth take station in place as a contingency on January 21.

If LNG vaporization facilities had been operational on Aquidneck Island when the low-pressure condition on the Algonquin system began to cause instability on the gas distribution system on the island, the injection of vaporized LNG into the gas distribution system likely would have avoided the need to curtail service in Newport on January 21, 2019. During interviews, no one at the Company disputed the reasonableness of this belief when the Division raised it. [124] However, based on its "design day" forecasting the Company relied upon for projecting need, the Company had made an operational judgment that LNG injections would not be needed for the

122 See the testimony in Docket 4872, page 35 of 50. Found at: http://www.ripuc.org/eventsactions/docket/4872-ngrid-jointrebuttal-w-att(10-22-18).pdf

winter of 2018-19.[125] While January 21 was not a design day, the Division believes accurate design day planning would have called for LNG facilities to be in place for the entire winter.

5.1.1 Design Day Forecasting

When determining whether LNG vaporization capacity or other actions or infrastructure investments are needed to assure reliable gas service, gas utilities apply criteria referred to in the gas industry as design day planning. Design day planning is based on a measure referred to in the energy industry as heating degree days ("HDD"). Specifically, generally accepted industry standards call for a forecasting analysis to assure that there is enough capacity and supply available to serve customers on the worst (or coldest) day that might realistically occur. It is based on a forecast of need tied to a "heating degree day" temperature. A "heating degree day" is the average of the lowest temperature plus highest temperature divided by 2, subtracted from 65 degrees.[126] 65 degrees is used as the baseline for measuring HDD under industry standards because it is the temperature when no heating or cooling is typically needed.

For Narragansett Electric in Rhode Island, the Company uses a design day HDD of 68 degrees.[127] In other words, if the utility follows industry criteria, it must plan its system and procurements to assure that on a day that reaches 68 HDD, there will be no gas service outages (assuming the system is functioning properly without incidents beyond the control of the utility). Translated into ordinary nomenclature, a 68 HDD is equal to an average temperature of -3 degrees Fahrenheit (i.e., 65-68 = -3). Under the Company's analysis, a 68 HDD would likely occur approximately once in 59 years.[128]

In the context of Aquidneck Island, the Company concluded that its design day criteria had been met without the need for supplemental LNG on Aquidneck Island.[129] This turned out to be an erroneous conclusion. In fact, the Company has since reconsidered how it was evaluating the need at Aquidneck Island and now acknowledges that there is a need for vaporized LNG on the island. While January 21 was not a "design day" (i.e., only 59 HDD), appropriate design day

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[125] See the testimony in Docket 4872, page 35 of 50. Found at: http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att(10-22-18).pdf

[126] For example, a day with a low of 5 degrees and a high of 16 degrees would be a 44 HDD: 65 - (5 + 16)/2 = 44.

[127] See National Grid's amended "Gas Long-Range Forecast and Requirements Plan for the Forecast period 2019/20 to 2023/24," ("LRP") page 13, filed in Docket 4816. Found at: http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf

[128] See the "LRP", page 13, cited in footnote above.

[129] See Division 12-16.

planning which appropriately considered hourly peak flows into the Portsmouth take station would have indicated the need for LNG on the island. This error was the result of a complex set of assumptions in planning, as described below.

5.1.2 Reliance Upon the Operational Balancing Agreement with Algonquin

Narragansett Electric has ten take stations on the Algonquin system for service into Rhode Island.[130] Each of the take stations have both a daily flow and an hourly flow contract limit. If either the daily or the hourly limits are exceeded, the Algonquin customers using the system (in this case Narragansett Electric) could be subject to financial penalties from the interstate pipeline (in this case Algonquin). However, it is well understood in the industry that it is not possible to deliver and take the precise quantities that are scheduled over the course of a "gas day." For that reason, customers on the interstate system each have an "Operational Balancing Agreement" (OBA) with the pipeline. For those interconnected customers with more than one take station from the same pipeline, under the OBA, at the end of the gas day all deliveries to each take station are aggregated and the interstate pipeline will typically accept the total in the aggregate, as long as it does not exceed the aggregated limits and the reliability of the system was not affected by any excess takes at any given take station.[131]

According to Narragansett Electric, it has been relying on its OBA for many years, where Algonquin has allowed the Company to aggregate all of its take stations for purposes of measuring both hourly and daily quantities.[132] Thus, to the extent the hourly or daily maximum was exceeded at the Portsmouth take station serving Aquidneck Island, Algonquin would accept the end result and not penalize the Company.[133] According to the Company, this has been occurring historically without any reliability issues or penalties. Because of this practice, National Grid has been doing its design day planning on a "portfolio-wide" basis for all of Rhode Island, believing it was not necessary to consider whether its maximum takes at any given location among the ten take stations might be exceeded.[134] The Company's supply planning group did not consider the forecast of

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[130] See Exhibit 1 to the Company's Operational Balancing Agreement with Algonquin, identifying he receipt points. Attachment DIV 4-1, page 5.
[131] Division 3-9. A copy of the OBA is attached to Division 4-1.
[132] Division 3-9.
[133] Division 3-9.
[134] See Division 3-4. See also the explanation provided by the Company to the Division in the Letter from National Grid to K. Lynch 1/25/19, provided in Appendix A.

deliveries that might come to the Portsmouth take station (in isolation) on a design day. The Company essentially considered its Algonquin delivery rights as a whole and balanced the aggregate of all its takes on any day and any hour across all take stations on the Algonquin system, including the Portsmouth take station.[135] The Company described its practice as follows:

> [T]he Company has understood, both through the OBA and through operational practices consistent for years, that exceeding maximum daily or hourly quantities at individual take stations off the Algonquin system would not and did not imperil reliable service on Aquidneck Island or anywhere else, so long as demand across the Company's take stations receiving gas from Algonquin did not exceed the total combined [maximum daily quantities] and the allowed imbalance tolerance on the day.[136]

The forecasting process used by the Company to determine capacity needs on the interstate pipeline system rested on this assumption Specifically, the forecasting department would forecast daily quantities and hourly demands throughout its system for design day evaluation. In performing this function, the department would provide the annual forecast of daily and hourly demands at each take station to engineering in order to allow for an evaluation of the local distribution system needs. However, the forecasting department would not provide the hourly forecast by take station to the Energy Procurement business unit that was responsible for evaluating interstate pipeline capacity needs.[137] As a result, the Energy Procurement business unit responsible for assuring adequate interstate pipeline capacity did not evaluate hourly peak needs at individual take stations for purposes of design day capacity and supply planning. This planning assumption and evaluation process, the Division believes, was a key factor leading to the Company's decision not to recommission the LNG facilities at the Naval Base or install the temporary LNG vaporization facilities at the Portsmouth take station for the winter of 2018-19.

[135] Interview, July 10, 2019.
[136] Division 3-9, page 2.
[137] Interview, July 10, 2019.

5.1.3 Forecasting Error and Subsequent Acknowledgement of Need for LNG

As will be explained below, in a separate proceeding and investigation in a Public Utilities Commission docket that arose in 2018, the Division inquired about hourly peak capacity limits into Aquidneck Island. In response, the Company performed an analysis of hourly peak demand for the Division, concluding that the hourly forecast did not indicate a need for new incremental pipeline capacity into Aquidneck Island until the winter of 2022-23.[138] In March of 2019, however, the Company disclosed that it had made a forecasting error relating to the contractual capacity limits into Aquidneck Island.[139]

Months before the events of January 21, 2019, the Division and the Commission were reviewing a proposal by National Grid to pay a $7.2 million energy efficiency incentive to the Navy for the installation of an 8 MW gas-fired combined heat and power (CHP) generation project at the Navy base in Newport (CHP docket).[140] During those proceedings, the Division questioned the Company's ability to supply such a large gas-fired project, which would create a substantial demand on the gas system on Aquidneck Island.

One area of inquiry related to the Company's forecasts. Specifically, the Division asked the Company in November of 2018 when the Company believed it would face a constraint on the island for adding new firm gas customers, including a request for peak hourly demand analysis.[141] The Company maintained that there would be no problem serving new gas customer load until the winter of 2022-23. The response included a forecast, indicating that the hourly limit at the Portsmouth take station was 1,122 DK/hr, but such limit would not be reached until the winter of 2022-23.[142] No mention was made in this response about the relevancy of the Company's Operational Balancing Agreement.

After the January 21 outage, the Division sent an official communication to Narragansett Electric indicating concern that the Company did not have LNG facilities on Aquidneck Island.[143] On January 25, 2019, the Company responded in a letter.[144] The letter maintained that there was

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[138] Docket 4755, Company's original response to Division 10-25. The Division asked the question on November 27, 2018. The Division did not receive a response to its question until January 25th – four days after the outage in Newport.
[139] Docket 4755, Division 10-25 Corrected and Supplemental.
[140] See PUC Docket 4755. The Company later withdrew its proposal.
[141] Docket 4755, Division 10-25.
[142] Docket 4755, Division 10-25.
[143] See Letter from K. Lynch to National Grid 1/24/19, provided in Appendix A.
[144] See Letter from National Grid to K. Lynch 1/25/19, provided in Appendix A.

sufficient pipeline capacity in the Company's portfolio to meet requirements on Aquidneck Island. The letter also contained the following statement:

> As explained during the recent Gas Recovery proceeding before the Public Utilities Commission in Docket 4872, the Company did not expect to need LNG operations on Aquidneck Island in winter 2018-19, assuming performance of suppliers, but instead expected it would need LNG operations on Aquidneck Island during the spring and/or summer of 2019 to assist the transmission pipeline company's (i.e., Algonquin's) periodic inspection of its pipe. The Company is exploring whether any options exist that will be large enough to provide supplemental supply on Aquidneck Island for the remainder of the winter.

The letter then mentioned the Company's reliance on the Operational Balancing Agreement and, in effect, continued to maintain that LNG was not needed.

On March 1, 2019, the Company filed a corrected answer with the Division and the Commission in the CHP docket, identifying the forecasting error, and changing the conclusion about the hourly forecast that had been provided on January 25.[145] The Company now disclosed to the Division and the Commission that the hourly limit was not 1,122 Dth/hr. Rather, it was only 1,045 Dth/hr. Most significant, the forecast showed that the limit would have been exceeded during the winter of 2018-19 had a design day occurred during that time. The Company's response then referred to its reliance on the Operational Balancing Agreement with Algonquin to manage capacity across all of its Rhode Island take stations.

Concerned with the response, the Division on March 4 asked another series of questions in this investigation to obtain a better understanding of what transpired with respect to the Company's forecasting. The response to the Division's follow-up questions reflected a significant change in the Company's view:

> The Company is re-evaluating its ability to serve additional incremental firm load to Aquidneck Island until such time that additional capacity

[145] Docket 4755, Division 10-25 Corrected and Supplemental.

> resources to delivery [sic] incremental supply to the Aquidneck Island system are in place. Furthermore, the Company has identified a need to recommission the LNG facility at the Newport Naval Station (LNG Facility) to supplement the supply capacity to the Portsmouth take station on the Algonquin system to ensure adequate supply to existing customers and provide supplemental supplies for reliability purposes in the event of another problem with deliveries to the Portsmouth Take Station.[146]

Thus, the Company was now indicating that there was a need to have LNG facilities on Aquidneck Island to assure reliable service to the existing customer load, but this time did not mention the Operational Balancing Agreement in its response.

When the Division probed further to understand why the Company was no longer relying on its Operational Balancing Agreement, the Company verbally informed the Division that Algonquin had sent a notice to all shippers on the Algonquin G-System on January 29, 2019. According to the Company, the Company interpreted the notice as indicating that Algonquin was now limiting the hourly takes of shippers at the take stations to the contractual limits.[147] As a result, the Company maintained that it could no longer rely upon the Operational Balancing Agreement to manage all take stations in the aggregate. Instead, each specific location now needed to be managed in a way that assured that the hourly and daily maximums at the take station are not exceeded, including the Portsmouth take station.

On July 2, 2019, in a separate filing of its amended Long-Range Plan on July 2, 2019, the Company gave a more complete explanation of its new planning process:

> On January 29, 2019, Algonquin Gas Transmission LLC (AGT). . . notified the Company (and all AGT customers served by AGT's G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. . . . Historically, AGT

[146] Division 3-5, page 2.
[147] After the outage of January 21, 2019, Algonquin sent a notice to all shippers on the G-System on January 29. A copy is provided in Appendix A, labeled as "Algonquin Critical Notice: 1/29/19."

> has not imposed any requirements that its customers manage [sic] meet the calculated hourly flow limits, nor has AGT restricted the Company's ability to balance its overall takes across all take stations. The January 29, 2019 notice expired on April 1, 2019. However, the Company reasonably expects that AGT (Algonquin) may issue a similar notice in the future, or even issue the types of orders described in the January 29, 2019 notice without first issuing another warning. Accordingly, the Company is making planning decisions to be able to comply with any such future orders. Because the Company's peak hour is greater than the [calculated hourly limits], the Company will now need to ensure that it has sufficient deliverability to meet peak hour requirements of its customers.[148]

In effect, the Company was asserting that – because of this January 29 notice – it had to abandon its old way of planning and now plan in a way that assured that hourly limits at the Portsmouth take station would need to be met.

During the investigation, it became apparent to the Division that there was a significant difference of opinion between the National Grid affiliated companies and Algonquin pertaining to the interpretation and interplay among the capacity contracts, tariffs, and Operational Balancing Agreements between National Grid affiliated companies and Algonquin.[149] National Grid affiliated companies, including Narragansett Electric maintained that the Operational Balancing Agreement allowed it to aggregate and balance hourly flows among all its take stations. In contrast, Algonquin maintained that the Operational Balancing Agreement did not.[150] Whether or not the Company did or did not have the right to manage its gas portfolio in accordance with the interpretation of the OBA, however, the Division believes that it was not reasonable for the Company to have been ignoring the hourly contractual flow at the Portsmouth take station.

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[148] Docket 4816, Long-Range Gas Supply Plan (LRP), filed July 2, 2019; pages 16-17.
[149] It is important to reiterate that the Division has no jurisdiction over Algonquin's pipeline business, tariffs, or its contracts. For that reason, it has no regulatory authority to probe the issue relating to the management of the Operational Balancing Agreements by Algonquin, as those agreements might impact hourly and daily limits and the reliability of the G-System. The Division has conferred with staff at the Federal Energy Regulatory Commission regarding the issue, but the Division cannot draw conclusions about the practice under FERC rules and tariffs.
[150] Algonquin Gas Transmission "Response to PHMSA Information Request JH33, March 15, 2016. ("National Grid does not have the contractual right to balance usage amongst various M&R stations on the G-System.")

Further, Narragansett Electric does not dispute Algonquin's authority to limit restrictions to the calculated hourly flows specified in its contracts. The Company only points to historical practices where the Company maintains that Algonquin never imposed such restrictions. But if the Company knew that Algonquin had the right to so restrict flows with properly issued notices and flow orders, it had a duty to assure that its system could sustain service in the event such notices or flow orders were issued.

Just as importantly, given the corrected hourly limit identified after the forecasting error was disclosed, the Division believes there has been an unacceptable design day risk present on the island. In other words, had a design day occurred at any time during the winter of 2018-19 (i.e., average temperature at minus -3 Fahrenheit), Aquidneck Island was at serious risk of a low-pressure condition, even without an equipment failure affecting the Algonquin system. If the Company had been focusing on the hourly limitations and forecasted correctly, it would have revealed the need to have LNG in place on Aquidneck Island for the winter of 2018-19.

5.2 Precondition Contributing to the Event: Lack of Contingency Planning for Aquidneck Island

Hindsight is always 20/20, and a significant lesson learned from the incident is that Aquidneck Island is uniquely vulnerable to low-pressure conditions on the Algonquin G-System. However, there was an event that occurred in 2014 that could have signaled a need for contingency planning for Aquidneck Island, even if such planning was not ordinarily employed for other areas of the Company's system. Such contingency planning also would have strongly suggested the need for vaporized LNG on the island.

5.2.1 Low-Pressure Event of March 7, 2014

In the Division's investigation, the Division learned from the Company that on March 7, 2014, the Portsmouth take station experienced a low-pressure condition from the Algonquin system that threatened service on Aquidneck Island.[151] According to the Company, Algonquin had not received the volume of gas it expected from the Maritimes & Northeast pipeline into Algonquin's system in Weymouth, resulting in the low-pressure problem on the G-System.

[151] Division 1-9.

On that day, it was only a 31 HDD (i.e., average temperature of 34 degrees Fahrenheit).[152] According to the Company, the system experienced very low inlet pressures into Portsmouth. The Company immediately took steps to bypass one of its regulator stations to mitigate the low-pressure conditions.[153] In addition, since the Navy was taking interruptible gas service for its central heating system and could switch to oil, the Company was able to stabilize the distribution system by interrupting service to the Navy, preserving system pressures to other customers in the Newport area.[154]

Like January 21, 2019, the event on March 7, 2014 did not occur on a design day. However, unlike the January event, the March 2014 event was a relatively normal seasonal day that should not have caused any stress on the distribution system at an average of 34 degrees Fahrenheit. Yet, system reliability was threatened because of conditions on the Algonquin system over which Narragansett Electric had no control.

According to the Company, after the incident, the Company made some improvements to its high-pressure distribution system in one area of Newport to make the system more resilient to lower delivery pressures from Algonquin.[155] The Company, however, did not alter its planning processes to evaluate how contingencies on the Algonquin system could impact Aquidneck Island under various scenarios.

5.2.2 No Scenario Modeling in Distribution Planning

During the investigation, the Division probed the degree to which Narragansett Electric's system planning involves modeling its gas distribution system for contingency scenarios relating to hypothetical failures or other similar incidents that could cause low pressure conditions. In response, the Company indicated that it "typically does not include contingency scenarios relating to hypothetical system failures or other similar low-pressure conditions."[156] In particular, with respect to Aquidneck Island, the Company has never modeled any contingency scenarios that assumed any kind of low-pressure condition occurring on the Algonquin G-System that is out of

[152] Division 9-2.
[153] Division 1-9.
[154] Division 9-4. The Navy is a dual fuel customer who has the ability to switch to oil for heating if interrupted by National Grid. The Navy was not burning natural gas on January 21, 2019, having already switched to oil for the entire day.
[155] Division 9-6.
[156] Division 7-1.

the Company's control. In fact, the Company stated: "The modeling of contingency scenarios that assume a low-pressure condition occurring on the Algonquin G system or any other transmission lateral out of the Company's control is not part of the reliability planning performed by the Company."[157] The Company further stated:

> The [Company's] approach to system modeling and planning assumes that transmission pipeline companies will deliver gas to the take stations at pressures equal to at least the minimum guaranteed contractual pressure. It is unreasonable to plan the system for 'worst case' scenarios similar to what occurred on January 21, 2019, where [Algonquin] delivered gas to the Portsmouth take station at pressures far below the contractual minimum pressure.[158]

Modeling contingency scenarios are a part of the gas business to assess impacts from the loss of supply. In fact, there are industry guidance documents published by the American Gas Association that confirm the desirability of such a practice.[159] While the Division is not drawing definitive conclusions about the extent to which the Company should be modeling contingencies across its *entire* system, the Division believes the Company should be modeling scenarios for Aquidneck Island that consider the effects of potential low-pressure conditions on the Algonquin system. Given (i) the March 2014 event, (ii) the configuration of the gas distribution system in Newport, and (iii) the vulnerability of Aquidneck Island to low-pressure conditions on G-System,[160] the Division believes contingency modeling should have been a part of its processes.

Section 6.0 Additional System Vulnerabilities

In the course of the investigation, the Division also evaluated other conditions existing prior to the event and the Company's preparedness for the emergency. This review also identified deficiencies in the Company's preparedness. It is important to note that the Division does not

[157] Division 7-2.
[158] Division 7-6.
[159] See the Chapter 5 on "Network Simulation" in *Gas Engineering & Operations Practices (GEOP) Series, Volume III, Distribution* (American Gas Association, Arlington VA – 1990) (p. 177, Table 35)
[160] See Division 13-3 and Division 15-2.

believe that the deficiencies identified in this section necessarily played a role in contributing to the low-pressure problem or causing the curtailment on January 21. Nevertheless, the Company should remediate the issues identified here.

6.1 Dispatching and Outage Mapping Processes

During gas emergencies, accepted utility practice suggests that a utility should have an efficient process that allows timely visibility to the areas of the service area from which "no gas" calls are being received. In turn, as the calls arise, there should be a mapping process that provides a clear picture of what is happening on the system.

The Company had already identified the need to improve its capabilities for its field technicians (among other process improvements) and has had a comprehensive gas transformation plan underway that is designed to improve the capabilities of its field technicians to identify, respond, and report on gas outages.[161] But the new system was not yet in place in January. Instead, an old pre-existing manual process was still being employed. The Company had a system in place to receive calls, generate orders for scheduling technicians, and send technicians to the location of gas outages. However, the Division believes the system was only adequate to address "no gas" calls in the ordinary course of business.[162] It was not effective for addressing emergency conditions occurring on a more widespread basis.

As the low-pressure condition on the Algonquin system began to affect service to consumers on Aquidneck Island in the late morning of January 21, 2019, the Company began to receive phone calls that were taken by the Company's Gas Dispatch system.[163] The number of "no gas/poor pressure" calls started small. But the count grew quickly in the afternoon hours. It is clear that the Company was aware of the pressure drop in the low-pressure system in Newport, but it is equally apparent that the command team did not have visibility to geographical scope of the outages in the low-pressure system as the outage calls increased.[164] As the calls were received, they were recorded in the Company's Customer Service System ("CSS").[165] According to the Company, technicians were sent to some of the locations where the calls originated to shut off

[161] Division 19-1, 19-2, and 19-3.
[162] See the description of the process provided in Division 17-5.
[163] Attachment DIV 1-14.
[164] See Division 17-7 and 17-8, compared to Division 1-1, page 4.
[165] Division 17-5.

service. But there was no system in place to be able to track the location of the outages for purposes of assessing the scope of the problem as events unfolded.

The Company maintains that Gas Dispatch "was in frequent communication with the Company's decision makers managing the response to the events of January 21, 2019."[166] According to the Company's narrative of events, and as quoted earlier:

> The Company expected that areas of no gas calls would occur on the southern peripheries or end points and crews could isolate those segments and maintain supply to the core integrated district. At 4:30 p.m., Dispatch provided a list of no gas calls. Engineering then prepared a map of the outages. Narragansett Electric then overlaid that outage map on the entire integrated low-pressure system and immediately recognized that the outages spread across all segments, including the northern and central segments.[167]

By the time the system was mapped, the Company could only confirm what now had become apparent about the widespread nature of the impact.

It does not appear to the Division that it would have made a material difference if the Company had visibility to the location of the outages earlier in time. The Company maintains: "If the emergency response command had completed the mapping earlier in the day, it would not have had a material impact on the shutdown process because the pace of the pressure drop did not allow for sufficient time to isolate an area of the integrated low-pressure system to prevent the additional outages on the other parts of the system."[168]

In addition to the lack of an automated mapping process, the Company's response to the outage calls on the island was not sufficiently prompt to provide the Company awareness of its system. The Company stated that 93 customer meter services employees were available to respond to outage calls on Aquidneck Island during the course of the day. While CMS technicians were not the only employees responding to the event, they play an important role in addressing customer

[166] Division 17-7.
[167] Division 1-1, page 4.
[168] Division 17-8.

shut offs.[169] According to the Company, at 10:45 am the "Customer Meter Services" (CMS) group was notified of the emergency conditions on Aquidneck Island.[170] At that point, CMS management personnel began to reallocate resources to the island in order to investigate the "no gas/poor pressure" orders and shut off the services at those locations. But the arrival of the technicians did not happen rapidly. As described in the sequence of events, the number of technicians was relatively small as the calls first came in around 11:09 am and it took a number of hours for more technicians to arrive over the course of the afternoon.[171]

After the call went out, there were only 10 CMS vehicles on the island by 12:15 pm.[172] By 2:13 pm, there were only 27 CMS vehicles on the island, a full three hours from when the first "no gas" call was received. By 3:55 pm, there were 29 CMS vehicles. It was not until after 4:00 pm that the number of CMS vehicles finally started rising significantly higher.[173] But that was over five hours from when the first call went out to dispatch all of the 93 CMS employees the Company maintains were available.[174] Moreover, the Company's system of recording the activity of arriving at a customer account and shutting off the service was manual, through which the technicians used manual outage cards. There was no system in place for the technicians to electronically report the activity as it occurred. The lack of a coordinated modern-day communication system between technicians in the field and the emergency command center also appears to have hindered leadership's visibility to what was occurring in the field

The Company does not know today how many individual customer meters were shut off during the course of the late morning and afternoon of January 21 prior to the curtailment order. When the Division requested the Company to provide the number of customers who were shut off between 11:00 am and 6:30 pm, the Company stated in response: "The Company cannot provide a specific count of how many locations were shut off between 11:00 am and 6:30 pm because the

[169] There were many other employees, including Instrumentation and Regulation, Field Operations, and other employees performing various duties. See, for example, Division 17-1.
[170] Division 17-1.
[171] See Division 17-12 and accompanying Attachment 17-12-1.
[172] The Company was unable to give the Division a count of the number of CMS technicians as they arrived on the island. As a result, a proxy was used to estimate the arrivals by tracking the vehicles. The Company maintains that some vehicles may have had two technicians. Given the limited data, the Division is using the vehicles as a proxy as well.

[173] Division 17-12.
[174] Division 17-1.

manual outage cards are not stored in searchable format that can be easily aggregated."[175] When the Division pressed further on this issue, the Company stated: "Because the manual outage cards are organized and stored geographically by outage zone, not by date, the Company cannot readily determine how many cards were filled out on January 21, 2019."[176] In fact, there is not even a place on the outage card for a technician to write down the actual time that a shutoff occurred.[177]

Narragansett Electric maintains that "most gas utilities use manual outage card systems or similar systems when responding to gas emergencies," which the Company apparently confirmed with the American Gas Association.[178] The Company indicates that many utilities are taking steps to modernize. The event here in Rhode Island should be an industry wake-up call to expedite that modernization process.

During its last rate case filed in 2017 and completed in the summer of 2018, the Company proposed substantial system improvements in the gas business that contemplated changes across all of its jurisdictions, including Rhode Island, Massachusetts, and New York.[179] This initiative, referred to as the "Gas Business Enablement" (GBE) program, has many important features, one of which is to put in place sophisticated and automated systems for use by field technicians. It also will link the location of outage calls directly to its GIS maps on a real time basis. The proposal was reviewed and supported by the Division, and ultimately approved by the Public Utilities Commission. The system is scheduled to be in place for the winter of 2019-20. The Division is supportive of the Company's ongoing efforts in its GBE program to modernize its emergency response plans and processes, recognizing the need to monitor implementation and system integration with other Company procedures. But the system was not in place on January 21. Nevertheless, the Company was aware that it had an antiquated system in use for the winter of 2018-19. As such, it could have implemented provisional emergency response plans that considered the antiquated nature of the system by implementing provisional mapping processes during the interim.

[175] Division 18-8.
[176] Division 18-12.
[177] The Division requested a sample of the cards, a copy of which is attached to Division 18-12.
[178] Division 21-4.
[179] See the testimony beginning at page 82 of the linked file, found at: http://www.ripuc.org/eventsactions/docket/4770-NGrid-Book7(ISP-GBE).pdf

6.2 Inability to Sectionalize

In cases where it becomes impracticable to shut off services individually in a timely manner when "no gas" calls are received, another industry-standard action available to gas utilities under certain circumstances is to identify the location of the outages as rapidly as possible and take steps to isolate (or "sectionalize") the affected areas. By sectionalizing, the action is intended to limit the impact from spreading, by shedding load to boost pressures to the remaining customers (among other purposes). One important question that the Division posed to the Company was why the Company did not attempt to sectionalize portions of the low-pressure system in Newport instead of curtailing the entire system at once.[180] In fact, the Company did "sectionalize" the portion of the low-pressure system located in Middletown early in the day when it shut off the regulator on Walcott Avenue serving the low-pressure system in Middletown shortly after noon.[181] But, no further sectionalizing took place for the remainder of the day.

The Company's answers to this question, however, at times were contradictory. Initially, during interviews, the Narragansett Electric Vice President for Asset Management told the Division that the Company could not sectionalize Newport because it did not have the necessary valves in the low-pressure system in Newport to isolate areas of the system.[182] Yet, when the Company answered written questions about the extent to which the low-pressure system in Newport could be sectionalized, the response stated that the Company "can sectionalize the low-pressure system in Newport during emergency conditions if there is a confined area experiencing the emergency conditions that necessitate the shut off."[183] Another response even stated that there was a process in place for isolating the system.[184] The Company then provided data indicating that there were 449 emergency shutoff valves in Newport.[185] The Division followed up with another written information request, pointing out what appeared to be a contradiction between the interview with the Vice President and the written answers that followed from others.

At a later interview session, Company representatives eventually conceded that there was no practical way to sectionalize the low-pressure system in Newport.[186] None of the technicians

[180] See Division 16-1, Division 18-1, and 18-2.
[181] Division 1-1, page 3.
[182] Interview, May 20, 2019.
[183] Division 18-2.
[184] Division 18-3.
[185] Division 18-4.
[186] Interview, July 18, 2019.

that had been dispatched to Aquidneck Island had any access to maps or other data that identified shut-off valves in the area.[187] Another response also conceded that the shut-off valves identified in the earlier response "are not associated with specific sectionalizing districts that would require annual maintenance to ensure they are operational."[188] Stated succinctly, there was never any possibility that that Company could have sectionalized areas of Newport as the outage calls mounted since the Company may have had valves in place on the gas distribution system but the Company had not developed a sectionalizing plan to maintain and utilize these valves in times of emergency to cut off portions of the gas system. The Company's explanation for the inconsistent written responses was that the person sponsoring the answer took the question literally and simply maintained that it was "technically" possible, even if not practically possible.[189]

One of the recommendations in this report is for the Company to perform a study to determine the feasibility, costs, and effectiveness of establishing some level of sectionalizing capability on the low-pressure system in Newport, as it could be critical to shutting off sections of the gas system in other types of gas emergencies.

6. 3 The National Grid Organizational Structure

During the course of the investigation, the Division also sought to obtain a more complete understanding of how National Grid in Rhode Island manages its gas distribution business. The gas distribution business in Rhode Island is a relatively small portion of the National Grid business in the United States. By way of comparison, National Grid has over 900,000 gas distribution customers in Massachusetts and over 1.8 million gas distribution customers in New York. In contrast, Rhode Island has only approximately 250,000 gas distribution customers.

National Grid utilizes a shared gas organization to provide services across jurisdictions. While there are many gas distribution employees who work only in Rhode Island, the gas distribution business is essentially managed through a multi-state organizational structure.[190] This has some advantages. One is efficiency and lower cost, as systems and processes are shared across more territory. Another is the sharing of best practices across lines from one management structure. However, there are downsides as well.

[187] Division 18-10.
[188] Division 18-11.
[189] Interview, July 18, 2019.
[190] Division 1-12 & Attachment DIV 1-12 pages 1-3.

Specifically, the cross-jurisdictional organizational structure can result in a management structure through which there is no single executive who has authority and visibility over the broad scope of gas distribution-related services, operations, risks, and processes that were exclusive to Rhode Island. In fact, the Company conceded during interviews that there is no one person who has a comprehensive understanding of the gas distribution business in Rhode Island.

Another organizational issue relates to the gas capacity procurement function. Oddly enough, while the organizational structure has gas distribution and LNG operations controlled through a chain of command leading up to one person in charge of all U.S. gas operations, the capacity procurement function resides elsewhere. Within the structure, the Energy Procurement group responsible for assuring adequate interstate pipeline capacity reports up to the National Grid senior executive in charge of a function referred to as the "Electric Transmission, Generation & Energy Procurement Business Unit." The mission statement of that function states on the organizational chart:

> The Transmission, Generation and Energy Procurement business unit is focused on driving our evolution to being a leading transmission company. The unit is accountable for managing the company's relationship with the Federal Energy Regulatory (FERC), ensuring our compliance with all FERC regulations, and, in partnership with the Strategy & Regulation Function, setting our FERC regulatory strategy. In addition, this business unit is also responsible for the safe and efficient operation of our power generation plants and for procuring natural gas and electricity for our customers.[191]

The energy procurement function does not appear to link up in a rational way to the overall mission of this particular business unit.

The jurisdictional President in Rhode Island appears to have some executive responsibility for the Rhode Island electric and gas distribution businesses. But he does not have the employees in gas operations directly reporting to him.[192] The Company maintained during interviews that this

[191] See Attachment DIV 1-12, page 6.
[192] See the organizational charts in Attachment DIV 1-12 pages 1-3.

can be addressed by implementing frequent and effective communication processes. The President, however, does not have any gas distribution experience or anyone who directly reports to him with gas distribution experience to assess whether the broad menu of services being provided by the cross-jurisdictional gas operations of the National Grid USA Service Company are effective for Rhode Island to address local concerns adequately.

Given the circumstances and the relative size of the Rhode Island service area compared to the larger multi-state organization, the Division believes that National Grid should assign an experienced gas distribution Vice President (or similar level employee), with broad knowledge of the gas distribution business, to the President of Narragansett Electric. This high-level employee should be given the responsibility to manage the relationship of the Rhode Island gas operations with the larger U.S. gas business and provide insight and assistance to the President (exclusively focusing on Rhode Island). Absent this experience and perspective, the Division believes that the President is "flying blind" to the realities of what may be needed to continuously improve gas service for Rhode Island consumers. This role also would serve well to provide appropriate focus on the regulatory and other business relationships within the state that are needed to operate an effective local gas distribution business. Further, as environmental and energy policies advance more climate change initiatives that directly affect the gas distribution business, it will be critical that there is an executive with exclusive local focus on the Rhode Island gas business.

6.4 Lack of a Comprehensive "After-Action Review"

The Division believes that a prudent utility will always perform some form of self-evaluation after-the-fact when an unprecedented event occurs that created great risk to public safety. During the interview process, National Grid personnel stated that it has a practice of performing such "after-action reviews" to assess the performance of its affiliates, including Narragansett Electric, following major emergency events. The Company identified such a review that it performed in February of 2019 relating to the restoration process following the curtailment.[193] However, the review was limited to the Company's response from the period when the curtailment occurred to when restoration was completed. Other than an uncirculated rough

[193] Attachment DIV 21-2. The "Emergency Planning After Action Review" is dated April 26, 2019, but the sign-in sheets show the process underway on February 8, 2019. The Company maintains that this document contains confidential commercial information which is exempt from public disclosure.

draft document dated January 22, 2019,[194] the Company has provided no reports, memos, presentations, board materials, or any other documentation that reflects any level of self-evaluation of how the Company responded to the low-pressure condition as the effects unfolded on January 21, 2019 prior to the curtailment decision in the early evening of that day.

Narragansett Electric does have an "Emergency Response Plan" (ERP) which includes a section on the need to perform after-action reviews.[195] The section unequivocally recognizes the need to perform such reviews.[196] The ERP also contains a template for documenting after-action reviews. The template contains a section entitled "Preparatory Actions." However, when the Company documented its review, the report skipped any analysis of "Preparatory Actions" and went directly to the outage restoration process. It appears to the Division that this may be the result of the Company being concerned that any self-critical document might be prejudicial to the Company should there be any lawsuits in the future over the events of that day.[197] The Division believes this lack of self-evaluation is unacceptable and inconsistent with good utility practice.

<u>Section 7.0 Failure to Notify the Division of the LNG Plant Outage</u>

While certain imprudent actions and inactions of the Company do not represent violations of a specific Division rule or regulation, the Division has identified on instance of a rule violation based on the Company's failure to provide a telephonic notification to the Division of the emergency shutdown of an LNG facility. (815-RICR-20-00-1, Section 1.14 A.3.) For that reason,

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[194] Attachment DIV 4-5-1, pages 8-11 & 19-23. The document was entitled "Algonquin Supply Newport Outage – Preliminary Lessons Learned" and was authored by the Director of the Gas Control Center. There were two drafts of the "Lessons Learned" document. The first draft contained a vague reference to the Providence LNG plant operations. However, the reference to the Providence LNG plant was deleted in the second draft. Both drafts are dated January 22, 2019.

[195] Division 21-1.

[196] Attachment DIV 21-1, page 179. (Note: The Company maintains that the document contains references to Critical Energy Infrastructure Information and, thus, is not available to the public.)

[197] An evidentiary rule in Rhode Island relating to the admissibility of "Subsequent Remedial Measures" in civil litigation allows evidence of subsequent remediation to prove an admission of fault. Apparently, the conventional doctrine in many other states is to exclude such evidence to prove admission of fault in order to encourage potential defendants to remediate problems before they cause another injury. Rhode Island is in the minority and allows the admission of such evidence. The Division has not researched this point, but there is a law review article on the subject. *See* Fielding, Brian (2009) "Rhode Island's 407 Subsequent Remedial Measure Exception: Why it Informs What Goes Around Comes Around in Restatements (Second) & (Third) of Torts, and a Modest Proposal," *Roger Williams University Law Review*: Vol. 14: Issue 2, Article 3, found at: https://docs.rwu.edu/cgi/viewcontent.cgi?article=1400&context=rwu_LR

the Division will issue a Notice of Probable Violation and issuing a fine of $39,000 to the Company. The specifics of the non-disclosure are described below.

Following January 21st, no one at Narragansett Electric informed the Division about the LNG facility shutdown in Providence. During that time, Company personnel attributed the low-pressure condition solely to the Algonquin valve malfunction that occurred in Weymouth. The Division then commenced its investigation not knowing that the Providence LNG facility had experienced a shutdown. The Division sent its first set of questions to the Company on February 5. The first question the Division asked was for the Company to provide a narrative of events.

Before the Division received a response to the its question, PHMSA held a conference call with the Division on February 21st to share information with the Division. During the call, PHMSA informed the Division about the shutdown of the Providence LNG facility that impacted the G-System pressures.[198] After receiving this information, the Division expected to learn more about the Company's understanding of the impact of the LNG shutdown on Aquidneck Island.

On February 28, the Company filed its responses to the Division's first set of information requests. In the narrative of events, the response said nothing about the shutdown of the Providence LNG facility.[199] In an attachment, the Company provided copies of some event logs. In one of the event logs, there was a reference to the Providence LNG shutdown.[200] The log contained a short comment: "Providence LNG called – shut down is currently trying to come back online 04:48" The log then contained appended comments updating the situation during the morning. Other than the copy of the event log, the Company did not inform the Division. In a 5-page response to a question that was intended to obtain a complete explanation of everything that occurred from the point of detecting low-pressures, the long narrative never mentioned anything about the Providence LNG facility or how the control room personnel were interpreting its impact at the time.[201]

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[198] On March 1, 2019, an article also appeared in the *NewportRI.com*, in which a representative from Enbridge disclosed the fact that the Providence LNG facility had experienced the outage. See: https://www.newportri.com/news/20190301/enbridge-points-to-national-grid-other-sources-for-newport-gas-outage

[199] See Division 1-1.

[200] See Division 1-2, Attachment DIV 1-2.

[201] Division 1-1.

Not having received any other description of the matter, the Division immediately submitted another set of questions to the Company to explore the issue. One of the questions asked specifically why the Company never informed the Division formally or informally about the emergency shut down of the Providence LNG facility. The Company's response is quoted below:

> The Company did not formally or informally notify the Rhode Island Division of Public Utilities and Carriers (the Division) on January 21, 2019, or during the weeks that followed, that the NGLNG plant in Providence experienced a shut-down on the morning of January 21, 2019, because: (1) the Company believes that failures and problems in the Algonquin Gas Transmission, LLC system caused the low pressure condition that led to the shutdown of the low pressure gas distribution system on Aquidneck Island, and (2) the Company did not and does not believe that the NGLNG facility's temporary inability to send out gas to the Company's distribution system caused the low pressure condition that led to the shutdown of the low pressure gas distribution system on Aquidneck Island.[202]

The Company's February 28th response is not satisfactory given other documentary evidence the Division subsequently collected from National Grid and its affiliates.

On April 9, in response to a Division request for emails on the subject, the Company subsequently provided a copy of an email dated January 21, 2019. The email was sent at 10:18 am, from the manager of the control center (Paul Loiacono) who was on duty that morning, to his boss Mr. Richard Delaney, describing the low-pressure event as it was unfolding. This was approximately 45 minutes after the control center employee had spoken with an Enbridge employee on the phone about the Weymouth valve failure. In pertinent part, the email stated the following:

> The loss of the LNG had an immediate impact to our distribution system, the 200 psi line quickly dropped out to 100 psi, and the 99 psi system began to sag off as well. We picked up flow at Crary St and the loss of LNG

[202] Division 2-10.

> naturally picked up the flow at Wampanoag Trail. This also had an immediate effect on the AGT G-System which supplies down to Portsmouth [sic] GS on Aquidneck Island. The inlet pressure to Portsmouth has collapsed from 459 psi at the time of the shutdown down to 90 psi. We have I&R standing by on the island top [sic] bypass reg stations if needed.
> Coupled with the plant shutdown was an issue that AGT was having up in Massachusetts that contributed to the G-System suffering. They had a frozen valve on the Hub Line (Maritimes NE) supply in Weymouth Ma. They have since bypassed this valve and pressures have recovered nicely in the Weymouth – Milton area of MA but will likely take several hours to show any relief on Cape Cod and Rhode Island which are fed from the G-System.[203]

The Company also provided a second email sent on the day of the event, January 21, 2019, at 3:22 pm, from Richard Delaney to Ross Turrini, National Grid's Chief Gas Engineer overseeing all of National Grid's gas operations.[204] The email forwarded Mr. Loiacono's email from 10:18 am that described the impact on the G System from the LNG shutdown, with the following note:

> Ross, Providence is back on line. Pressure have not started to recover at Portsmouth. Rich.

Another email sent on January 21, at 4:54 pm by and to employees in the Energy Procurement Business unit contained the following observation:

> NGLNG has been struggling all day . . . it tripped off earlier today . . . . killed pressures. . . which were already suffering as there were low inlet pressures from AGT.[205]

[203] Attachment DIV 4-4-1, page 39. See also Division 2-2 Supplemental and accompanying letter.
[204] Attachment DIV 4-4-1, page 39.
[205] Attachment DIV 4-4-1, page 45.

While this email did not involve the control center, it reflected knowledge of the Company that the shutdown of the Providence LNG facility may have had an impact on the Algonquin G-System.

The Company also provided copies of some handwritten notes of a phone call that occurred between the jurisdictional President of the Massachusetts gas distribution company, Marcy Reed, and Bill Yardley, a high-level executive of Enbridge.[206] The notes are transcribed below:

> Bill Yardley 11:18 am 1/30/19, - (called me b/4 - would call him)
> Prov LNG – everything went haywire after that
> PHMSA, FERC, etc asking for their data
> Weymouth – nothing to do w/ this
> Tried to not be public, but RWT[[207]] comment makes it difficult
> d/n want to throw us under the bus
> RWT [illegible] re: Weymouth – its all folks have grabbed onto Enbridge BOD – pushing BY to defend himself Not running to press, but basically need to call PHMSA, FERC Yesterday data – o/s [illegible] – it'll be compelling to all that your overtakes are the problem. Not sure why PHMSA involved – s/b FERC

There is another email that was provided to the Division on April 9. The email was dated January 31, 2019, sent by Mr. Turrini at 10:26 am to another employee, copying upper management officials at National Grid.[208] The email was Mr. Turrini's comment on a proposed draft communications document. Mr. Turrini's note said:

> Jim,
>
> We should tone down what we say about the root cause, as we need to fully understand all the data and the exact root causes (as there will probably multiple [sic], their valve failure, utilities over taking from pipelines and

[206] Attachment DIV 4-7-1, page 3. See also Division 2-18.
[207] RWT are the initials of Ross Turrini, Senior Vice President for Gas Operations of National Grid.
[208] Attachment DIV 4-6-1, page 6.

> our LNG facility). I am back in the office on Monday. If you need to talk to me I can be reached on my cell phone tomorrow afternoon. Ross[209]

Given the documents provided by the Company to the Division, it is apparent that Company management knew immediately on January 21 that the shutdown of the LNG plant impacted the Algonquin G-System and gas pressure at Portsmouth. The Division questioned the Company on this issue in interviews, including examination of Mr. Turrini, who steadfastly maintained that he believed from the beginning of the incident that the Providence LNG facility did not contribute to the causes of the outage, even though other employees working under his line of authority expressed a different view at the outset of the event.

Mr. Turrini maintained during the interviews that there was no intention on his part or the Company to deliberately conceal the fact that an outage at the LNG facility occurred. In fact, Mr. Turrini stated that he believed at the time that the Division was aware that a shutdown had occurred. For that reason, he did not believe it was necessary to formally or informally contact the Division to disclose that a shutdown had occurred.

Notwithstanding Mr. Turrini's explanation during the interview, the Division has regulations that require the gas distribution company to disclose to the Division by telephonic notification of any incident involving an "emergency shutdown" of an LNG facility. 815-RICR-20-00-1, Section 1.14 A.3.[210] While the LNG facility itself is owned by an affiliate of the gas distribution company that is regulated by the Division, the LNG facility injects natural gas directly into the gas distribution system over which the Division has regulatory authority. For that reason, when the LNG facility shut down on January 21 – one of the coldest days of the year since 2005 – Narragansett Electric had a legal duty under the Division's regulations to notify the Division. However, the Company did not notify the Division within a reasonable time after the occurrence.

Given this noncompliance with Division regulations, the Division will be serving a Notice of Probable Violation on the Company, including a fine that is calculated at the statutory maximum

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[209] It appears to the Division that Mr. Turrini's note on January 31, describing the probable root cause to be "multiple," was correct. Yet, the Company has never been willing to concede this in any of its responses or interviews with the Division.

[210] The event log from the National Grid control center described the incident as an "ESD," which the Company has confirmed means "emergency shut down." See Division 2-11.

of $1,000 per violation. Counting each day from the event as a separate violation, there were 39 days from January 21 to February 28, when the Division received the event log reference from the Company that identified the fact that a shutdown had occurred. This equates to a fine of $39,000.

As described in the next section, this penalty represents only one portion of the potential financial impact of the outage on Narragansett Electric and National Grid shareholders.

Section 8.0 Recommendations

This section of the Report details recommendations of steps for Narragansett Electric to undertake to enhance the reliability of the gas distribution system.

8.1 Positive Observations Regarding the Performance of Narragansett Electric

The purpose of the Division's Report was to identify the cause(s) of the outage, determine whether any regulations were violated, and make recommendations for future improvements designed to assure that an event like this does not occur again. For that reason, much of this Report evaluates the events and the Company's performance with a critical eye. However, in the interest of providing the public complete information, there are some areas in which Narragansett Electric performed well and that should be acknowledged.

First, once it recognized the gravity of the situation in the late afternoon of January 21, Narragansett Electric made the correct decision to curtail service for the entire low-pressure system in order to protect public safety. The Company acted decisively when it became clear that no other options were available, even though it would lead to an unprecedented outage event that would negatively affect customers and, potentially, the company's reputation. To do otherwise would have endangered public safety.

Second, Narragansett Electric should be commended for preserving the high-pressure systems on Aquidneck Island. The steps it took to maintain adequate pressures to those segments helped to avoid what could have been a major catastrophe had the high-pressure systems serving critical facilities on that extremely cold day been lost.

Third, Narragansett Electric responded promptly and robustly in the days following the curtailment. A virtual army of technicians and staff descended upon the Newport area to complete the restoration process meter by meter in difficult conditions.

Finally, once the restoration was complete, Narragansett Electric voluntarily reimbursed certain categories of costs incurred by numerous customers who had been inconvenienced and faced with hardship.

8.2 Recommendations and Regulatory Expectations

The Division has identified deficiencies in Narragansett Electric's planning, organization, and internal processes. In parallel with the investigation, Narragansett Electric began to address some areas of need. Below is a description of the Division's recommendations and expectations for future action, the first three of which have already been adopted by the Company:

(1) **Improvements in Gas Long-Range Planning**: Prior to January 21, 2019, the Division had already identified problems with the way that Narragansett Electric performs its long-range capacity planning and had taken steps to recommend improvements to that planning process. In addition, the Investigation confirmed forecasting deficiencies, described in this Report. Narragansett Electric has now formally agreed with the Division to alter its planning processes to include hourly peak demand at each gas take station serving Rhode Island. The company has implemented this recommendation in a filing made in Commission Docket 4816 on July 2, 2019.[211]

(2) **Winter Deployment of LNG Facilities on Aquidneck Island**: Considering the event of January 21 and the Division's scrutiny, Narragansett Electric has agreed to deploy temporary LNG facilities on Aquidneck Island each winter to address the need to have capacity that meets hourly peaks, including on the gas design days that have the greatest demand for gas. The presence of LNG facilities will also serve as a contingency resource on non-design days in the event of a low-pressure condition occurring on the Algonquin system in the future.

[211] The plan can be found at: http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf

(3) **<u>Evaluation of Reinforcing the Lateral Serving the Portsmouth Take Station</u>**: Aquidneck Island is served by only one take station at Portsmouth, which, in turn, is served by a single six-inch lateral pipeline.[212] However, the Algonquin G-System leading up to the lateral has both twelve-inch and six-inch pipes. Narragansett Electric should engage with Enbridge to determine the feasibility of reinforcing service into Portsmouth by having Algonquin add a twelve-inch pipe in parallel with the existing six-inch pipe.

(4) **<u>Implementation of Demand Response Initiatives on Aquidneck Island</u>**: In addition to reinforcing the system, the Division recommends that Narragansett Electric implement a demand response program designed to reduce peak hourly demand at the Portsmouth take station. Such a program also could mitigate or prevent the effects of low-pressure conditions during cold weather events that might threaten reliable service.

(5) **<u>Contingency Scenario System Modeling and Emergency Response Planning</u>**: Given the vulnerability of Aquidneck Island to gas low-pressure conditions, the Division recommends the Company implement a scenario-based contingency planning process. Such process should include an annual scenario modeling and planning process that leads to the development of a detailed emergency response plan. The Division recommends that Narragansett Electric work with the Division to develop a process reasonably acceptable to the Division to establish this process, which would include updates to the Division.

(6) **<u>Evaluation of the Feasibility of Establishing Sectionalizing Districts in Newport</u>:** During the investigation it became clear that the low-pressure distribution system in Newport – as a practical matter – was not capable of being sectionalized to isolate problems on the system. The Division is requesting that Narragansett Electric conduct a thorough study of this issue to evaluate the feasibility of establishing sectionalizing districts for Aquidneck Island and other potential low-pressure risk areas across Rhode Island. The study should consider the costs and benefits of such an endeavor. The Division is requesting the Company provide such study to the Division.

[212] See Division 13-3.

(7) **Establishing a Process for Emergency Mobilization of LNG**: As the events unfolded on January 21, Narragansett Electric made a significant effort to mobilize LNG to Portsmouth on extremely short notice. By the time temporary LNG equipment arrived, it was too late. The Division recommends that Narragansett Electric study the feasibility and practicality of putting in place a system through which LNG can be mobilized on short notice, and report back to the Division on the analysis. While LNG will be in place on Aquidneck Island in the future, it is conceivable that there could be an emergency condition elsewhere in the system, where emergency deployment capability could be critical to system stability.

(8) **Interim Mapping and Tracking Process**: As explained in the Report, Narragansett Electric is in the process of implementing new systems that will allow greater real-time visibility to the location of gas outages. The system will link the outage calls to the GIS maps of the distribution system. To the extent the new system is not fully operational for the winter of 2019-20, the Division recommends the Company employ a manual mapping and tracking process to provide visibility to outages as they occur and updates when an area of the system appears to be affected by emergency conditions. This interim solution should not only be employed for events on Aquidneck Island, but should be incorporated into emergency response planning across the state-wide system.

(9) **After-Action Review Processes**: The Division has noted that Narragansett Electric has not produced any documentary evidence that it has performed a thorough "after-action" review of what occurred between the time the low-pressure condition was identified on January 21 through to the time that the Company decided to curtail service in the low-pressure system in Newport. The Division recommends that the Company establish a systematic review process that occurs, without delay, following a significant event affecting public safety and the reliability of gas service. Any such review should be submitted to the Division. Narragansett Electric should conduct such an after-action review for the January 21, 2019 event, taking into account the deficiencies identified in this Report.

(10) **<u>Improved Communications Between Narragansett Electric and Algonquin</u>**: On January 21, when the Providence LNG facilities experienced the shutdown, there was no immediate communication to Algonquin to notify their control center of the shutdown. The Division recommends that National Grid and Enbridge establish communication protocols for the real time notification of a shutdown of the Providence LNG facility or other similar events that have a potential effect on the Algonquin system.

(11) **<u>Appointment of a Vice President for the Rhode Island Gas Business</u>**: As described in Section 5.3 of this Report, the Division has concerns about the organizational structure of the gas business in Rhode Island. Specifically, there is no executive level person in Rhode Island who has gas expertise and responsibility for the management of the gas business in Rhode Island. For the reasons given in that section of this Report, the Division is recommending the appointment of a Vice President-level (or equivalent level) executive, reporting directly to the jurisdictional President. This Vice President would have focused responsibility, ownership and accountability for all aspects of gas service in Rhode Island.

(12) <u>Implement the recommendations of the U.S. Pipeline and Hazardous Materials Safety Administration report on this incident.</u>

8.3 Ratemaking and Cost Recovery

In response to an investigation question, Narragansett Electric has estimated that the incremental costs it incurred as of September 30, 2019 from the January 21 outage were in excess of $25 million. These costs are itemized below. The complete response from Narragansett Electric is included in the Appendix.[213]

[213] Division 22-1

Item	Cost category	Amount
1	Internal company labor including overtime	$8.5 m
2	Contractors	$9.3m
3	Meals, lodging and logistics (materials and transportation)	$3.8m
4	Customer claims	$2.0m
5	Claims reserve	$3.0m
6	Business restoration and charitable donations	$0.5m
7	Portable LNG from Colonial Gas (MA)	$0.1m
8	Outside legal costs	$0.6m
9	Total costs	$27.8m
10	Less base labor costs	($2.7m)
11	**Total Incremental Costs**	**$25.1m**

As a general matter, ratemaking in Rhode Island, as in other United States jurisdictions, is typically prospective. Regulated utilities use docketed proceedings before the Public Utilities Commission to present historical data as evidence for what the utility's costs will be in future years. Once this amount – the revenue requirement - is approved by the Public Utilities Commission in a contested general rate case, utilities may collect the revenue requirement from ratepayers. In general, if actual expenses are less than expected utilities may retain the savings as additional earnings for shareholders. Conversely if expenses are greater than expected then utilities must bear the costs, reducing earnings for shareholders. In other words, after rates are set in a general rate case, the utility cannot change base distribution rates to retroactively charge customers for unexpected higher costs that were incurred in the ordinary course of business. Although in Rhode Island many aspects of utility operations, such as certain safety and reliability infrastructure investments, standard offer service, and energy efficiency, are statutorily exempt from this ratemaking mechanism, the inherent structure of ratemaking is designed to prevent utilities from recovering higher costs from ratepayers retroactively.

In Rhode Island there is a narrow exception to the general rule of prospective ratemaking that allows a utility in the context of an unusually severe storm to seek recovery of extraordinary expenses.[214] Narragansett Electric may, at its own discretion, seek to recover the incremental costs of the outage through a special filing before the Public Utilities Commission, relying on the exception cited above or some other provision it may believe applicable. Any petition for extraordinary cost recovery would require the approval of the Public Utilities Commission.

Based on the information the Division has gathered to date through its investigation and in coordination with PHMSA, it asserts that multiple factors contributed to the curtailment of the low-pressure system on Aquidneck Island. While one precipitating factor was outside the control of any of the parties involved – the high demand of many customers on the G-System on January 21st due to extremely cold weather – the other two factors were within the control of either Enbridge, National Grid LNG or Narragansett Electric.

The two precipitating events were, first, the programming error of Enbridge's affiliate that caused its flow valve at Weymouth, Massachusetts to malfunction. Had Algonquin programmed its valve in Weymouth correctly, modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment. As the provider of interstate gas transportation, Algonquin had a duty to program its meters and valves correctly to assure safe and reliable service to its customers, including Narragansett Electric. But, in this case, it failed to do so.

Second, the National Grid LNG shutdown of its LNG vaporization facility in Providence contributed to the low-pressure condition when its vaporizers failed. According to PHMSA, National Grid LNG experienced a similar emergency shutdown in November 2018 which they did not adequately investigate or resolve.

As important as these two precipitating factors, however, were the planning and forecasting errors of Narragansett Electric which led the Company to conclude that it did not need to have LNG vaporization capability on Aquidneck Island. If backup LNG vaporization had been in place, Narragansett Electric could have survived the low-pressure condition without an outage by supplementing Aquidneck Island with the vaporized LNG.

The Division has carefully considered the position it would adopt in the event a request for extraordinary cost recovery were filed by Narragansett Electric. While the outage on January 21 would not have happened without the combination of precipitating events occurring, the Division believes that from a ratemaking perspective, Narragansett Electric ratepayers should not bear the

[214] *Narragansett Electric Co. v. Harsch,* 368 A.2d 1194,1206 (R.I. 1977).

restoration and other post-event incremental costs incurred from the outage. Those costs should be borne by one or more of the gas service providers. In any event, the decision of whether ratepayers should reimburse Narragansett Electric for any of the costs not recovered from the other service providers would be made by the Public Utilities Commission. The Division, however, is not offering any opinion on how responsibility for the resulting costs to Narragansett Electric might be allocated among these parties in any civil litigation.

8.4 Conclusion

This Report concludes the summary investigation into the events of January 21, 2019. Based on the findings of the Report and pursuant to §39-4-14, the Division will issue a Notice of Probable Violation to Narragansett Electric for the failure to notify of the emergency shut down of the Providence LNG facility. The Division will oppose any potential proposal from Narragansett Electric to recover the $25 million of costs related to the outage and restoration from ratepayers.

This Report does not end the Division's oversight of Narragansett Electric's gas distribution business. As reflected in its recommendations, the Division has identified areas it believes Narragansett Electric must address in the immediate future. These areas will be a primary focus for ongoing Division regulatory oversight of Narragansett Electric. Although Narragansett Electric has taken steps since January 21, 2019 to address some of the deficiencies identified in this Report, the Division will continue to exert its statutory supervisory authority under Title 39 of Rhode Island General Laws to address the recommendations identified in this report to maximally reduce the possibility of a similar event recurring to Rhode Island gas customers.

Beyond the events of January 21, 2019 themselves, the lessons of the Aquidneck Island gas service interruption should inform discussion among state regulators, Narragansett Electric and other stakeholders to consider the long-term development of the gas distribution business.

Heating Sector Transformation in Rhode Island

Pathways to Decarbonization by 2050

PREPARED FOR

Rhode Island Division of Public Utilities and Carriers

Rhode Island Office of Energy Resources

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NOTICE

- This report was prepared by The Brattle Group, with support from Buro Happold and Jens Ponikau of Buffalo Geothermal Heating, 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 as a whole and not in parts. 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.

- We are grateful for the valuable contributions of Senior Research Analyst Maria Castaner, the OER, DPUC, the Governor's office, and the many stakeholders who participated in the process.

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Executive Summary

As part of Rhode Island's commitment to economy-wide decarbonization, this report examines solutions to transform the state's heating sector. Dominated by space heating for the residential and commercial sectors, but also including water heating and industrial heating, the heating sector represents approximately one-third of the state's overall greenhouse gas emissions.[1]

There are many solutions for decarbonizing the heating sector, but they fall into three broad categories:

1. Reducing energy needs by improving building energy efficiency
2. Replacing current fossil heating fuels with carbon-neutral renewable gas or oil
3. Replacing current fossil-fueled boilers and furnaces with electric ground source or air source heat pumps powered by carbon-free electricity

The industrial sector may need other types of solutions, which can be very application-specific.

To transition to decarbonized heating fast enough to meet mid-century decarbonization targets, Rhode Island will need substantial policy support. The reasons include low fossil fuel prices (particularly for natural gas), which also do not reflect the social costs of greenhouse gas emissions; switching to electrified heating solutions requires substantial initial costs for equipment and installation compared to replacing boilers or furnaces; and other more qualitative factors such as information deficits, immature supply chains, a natural reluctance by consumers to change what seems to work well.

Rhode Island must base its policy framework for heating sector transformation on an understanding of the relative economic attractiveness of various decarbonization solutions. **Figure ES 1** shows the projected range of average annual heating costs in 2050 for a representative existing single-family home in Rhode Island, using existing fossil fuels (on the left) or several alternative decarbonized heating solutions (on the right). This figure shows two key insights:

1. For natural gas customers, who represent the majority of heating customers in the state, all of the decarbonized heating solutions will likely result in some increase in overall heating costs. This is less clear for fuel oil and propane customers. However, customer adoption of no-to-low carbon heating solutions will not take place in isolation. Viewing heating transformation within the context of broader decarbonization efforts across the electric

1 Although not directly a part of the heating sector, cooling will also play a role in the heating sector transformation since some heating equipment (notably heat pumps) can also provide cooling.

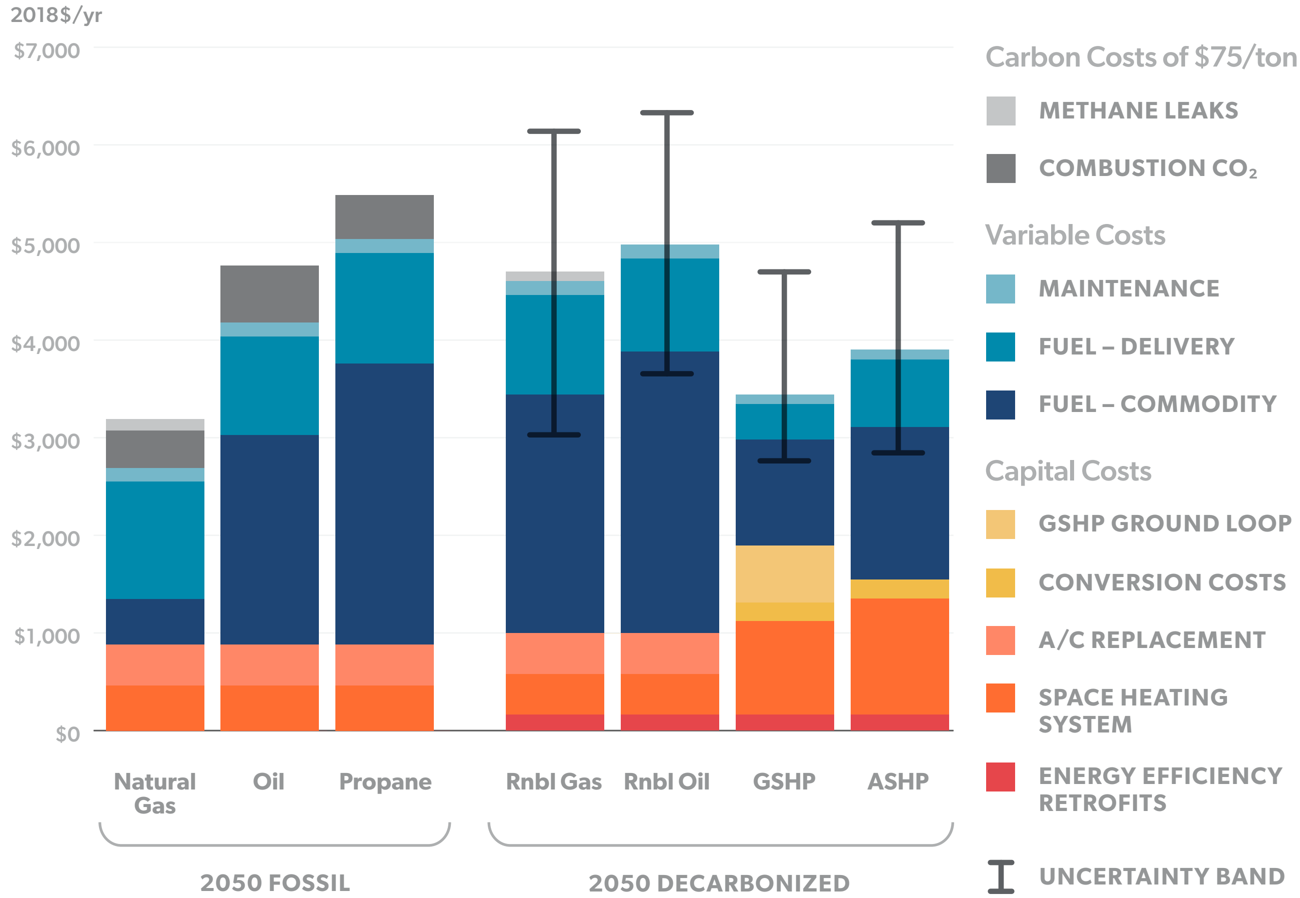


FIGURE ES 1: ANNUALIZED COST OF SPACE HEATING IN 2050, REPRESENTATIVE SINGLE-FAMILY HOME, BOOKEND SCENARIOS, 2018$

and transportation sectors, total consumer energy expenditures are likely to be similar to what is paid today in a fossil fuel-based system.

2. From today's perspective, no single solution is clearly more economically attractive than the others. This is due to the high uncertainty related to how the costs of all decarbonized heating solutions will evolve over the coming decades. The heights of the bars themselves are less important than the uncertainty bands around them (represented by black bands extending above and below the tops of the bars). These uncertainty bands are largely overlapping for the decarbonized technologies, indicating that it is not clear at this point which of these technologies will be most economical in the long run.

The analysis in **Figure ES 1** assumes that as part of decarbonizing the heating sector, cost-effective energy efficiency measures such as air sealing and attic insulation will be implemented in essentially all Rhode Island buildings. Doing so lowers the challenge to decarbonize heating and saves consumers money, which is relevant for all consumers and may be particularly important for disadvantaged communities.

This particular analysis is based on a set of "bookend" scenarios that assume for each decarbonized technology that this technology provides all heat across New England. It compares cases where fuels (gas and oil, in renewable forms) continue to primarily provide heat; or for electric heat pumps, assumes 100% adoption of either ground source heat pumps (GSHPs) or air source heat pumps (ASHPs). This captures the potential impacts of these technologies on the region's overall energy systems. For instance, the economic attractiveness of electric heat pumps

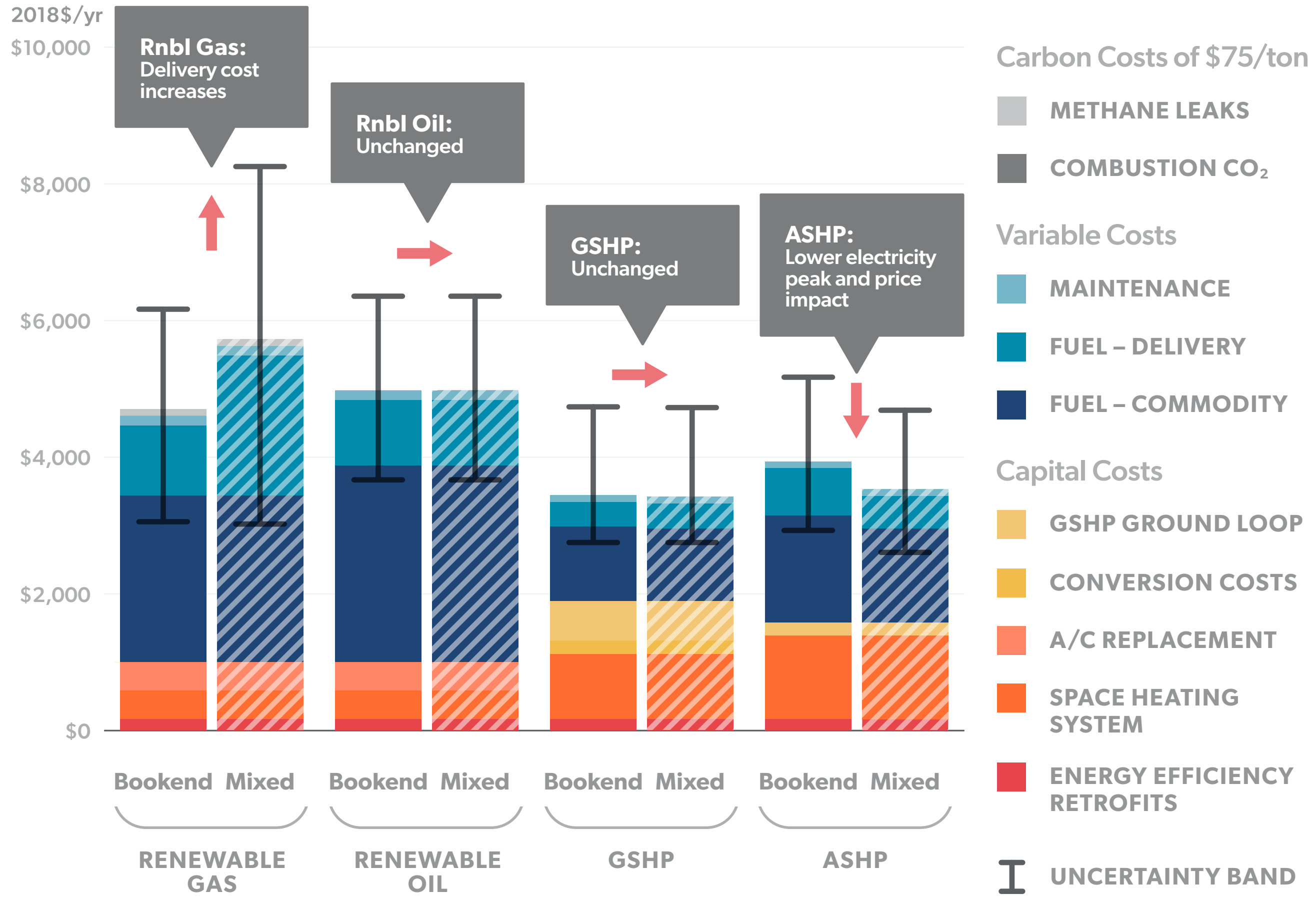


FIGURE ES 2: ANNUALIZED COST OF SPACE HEATING IN 2050, REPRESENTATIVE SINGLE-FAMILY HOME BOOKEND VERSUS MIXED SCENARIOS, 2018$

depends in part on the cost of (clean) electricity, which in turn depends on the impact that heat pumps will have on the electric system. Heat pumps themselves represent a substantial demand for electricity and can affect the price of power. Similarly, the attractiveness of renewable gas depends on its cost, which depends on the total gas volume demanded regionally and nationally, since low-cost supplies are limited.

One important lesson from these bookend scenarios is that widespread ASHP adoption could require substantial additional investments in the regional electric power system, and could create operational challenges. At very low outside temperatures, when the need for heat is greatest, ASHPs become significantly less efficient. If ASHPs are adopted widely, this could create extremely high peak electric demand during a few very cold days.

Since such bookend scenarios are unlikely to represent actual adoption of decarbonized heating solutions, Figure ES 2 shows how the results might change under one of many possible more-balanced adoption scenarios. This example shows a scenario that assumes that by 2050, electric heat pumps (one-third each by ASHPs and GSHPs) are providing two-thirds of heating; that (renewable) gas – which loses only 50% of volume relative to today – is providing most of the remaining heat; and that oil is providing the remaining amount.

This more mixed adoption of all the decarbonized heating solutions partially mitigates the extreme impact of 100% ASHP adoption on electric system peaks (and the resulting cost of electricity), making ASHPs relatively more attractive. On the other hand, reducing delivered gas volumes, due to increasing

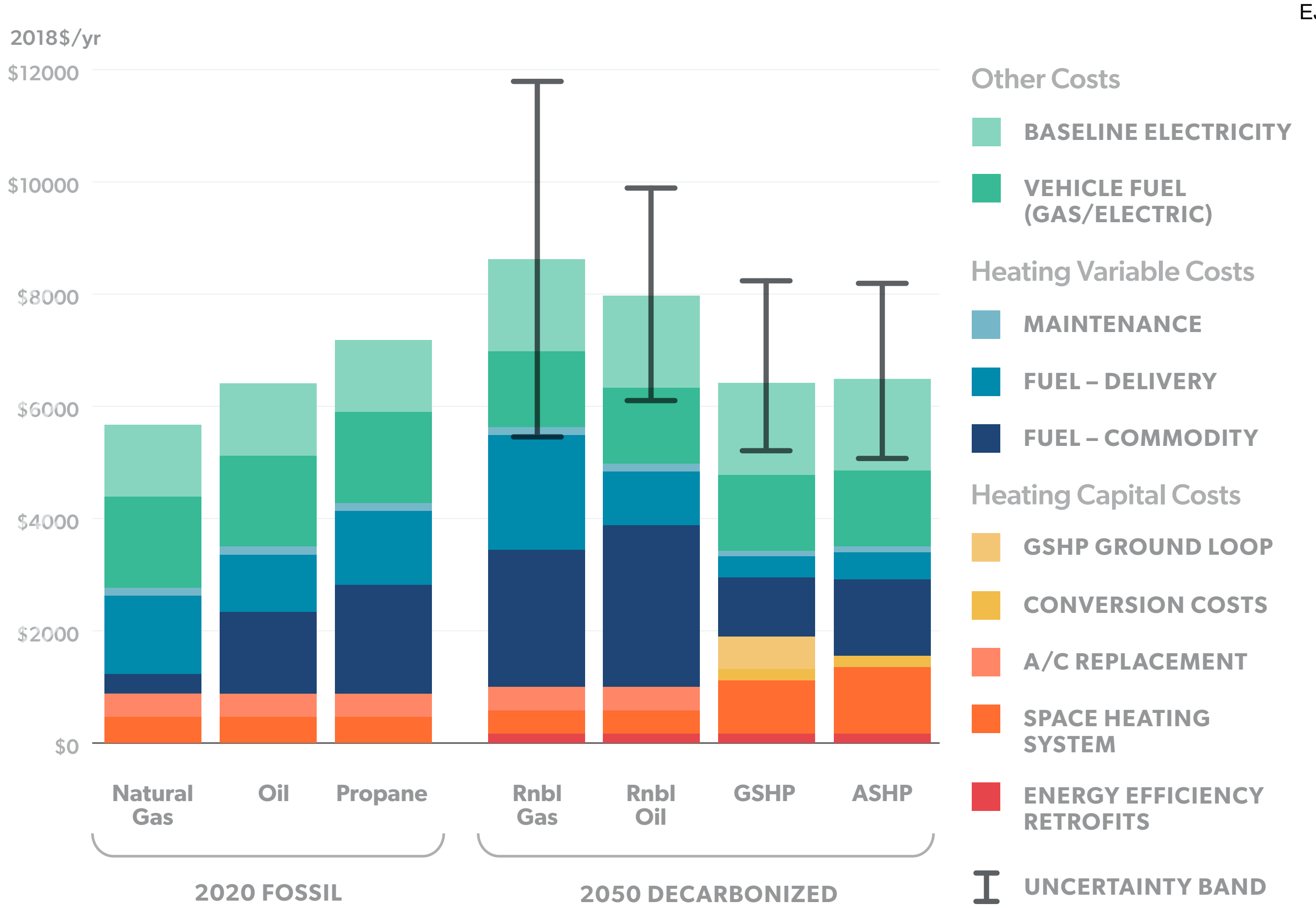


FIGURE ES 3: TOTAL ANNUAL ENERGY WALLET COMPARISON FOR REPRESENTATIVE CONSUMER: 2020 VS 2050 MIXED SCENARIO, 2018$

Note: Uncertainty band reflects uncertainty on heating costs as above, plus the effect of electricity price uncertainty on other end uses. Gasoline price excludes federal and state taxes. Water heating cost is not broken out explicitly, though to the extent electricity is currently used for water heating, this is included implicitly in Baseline Electricity Consumption.

energy efficiency or conversions to electrified heat, could increase the delivery cost of renewable gas, making it relatively less attractive. But, importantly, the more balanced adoption pattern of the Mixed Scenario does not alter the basic conclusion that no decarbonization solution is clearly preferred. The uncertainty ranges of the decarbonized technologies still largely overlap one another. Because the relative attractiveness of heating decarbonization solutions is sensitive to a) peak electric impacts and b) gas volume impacts, developing a better understanding of these effects, and opportunities to mitigate them, will be an important policy focus in the coming years.

Finally, the decarbonization of heating will not take place in isolation. Rather, it is embedded in broader economy-wide decarbonization efforts, including a likely shift toward electrified transportation. Heating decarbonization, and in particular the level of electric heat pump penetration, can affect electricity prices. This could have broader impacts on consumers' "energy wallet" – their total energy expenditures on baseline electricity consumption and electric vehicle (EV) charging, in addition to heating. However, changes in heating costs could be offset or exacerbated by impacts on other elements of the energy wallet, particularly transportation. EVs are expected – at least by 2050 – to have lower operating costs than current internal combustion engines.

Figure ES 3 compares a representative consumer's energy wallet spending today with what energy spending might look like by 2050, considering the various decarbonized heating solutions. The figure indicates that the attractiveness of ASHPs would not decrease substantially when considering the overall energy wallet. It also shows that, compared to 2020, any potential increase in heating cost could be at least partly offset by cost decreases elsewhere in the energy wallet, and by savings through energy efficiency. This does not mean that individual consumers or businesses will not see changes in their heating (and energy wallet) costs. Policy likely plays a key role in mitigating any potential cost increases, particularly where it may affect populations or industries that are vulnerable to increasing energy costs (and thus could be reflected in the state's economy).

The same broad conclusions apply to space heating uses in other settings, such as larger (multi-family) residential and commercial buildings, as well as to domestic water heating. Finally, various decarbonization solutions also exist for the remaining smaller uses of heat, such as electric cooking and clothes drying.

FIVE THEMES TO GUIDE RHODE ISLAND'S PATH FORWARD

The conclusion of this quantitative assessment of the relative attractiveness of various heating decarbonization solutions in Rhode Island is that, at present, there is no clear winning approach. Rather, the relative attractiveness of decarbonizing heating in the state depends on the evolution of the relevant costs – renewable gas, renewable oil, ASHPs, and GSHPs – which are highly uncertain today. Also, the attractiveness of the solutions in specific instances will depend on the particular context – the particular building, location, or application. In addition, each of the decarbonization solutions faces unique adoption and implementation challenges that Rhode Island will need to address to enable broad adoption over time.

This implies that, for policy to support Rhode Island's heating sector transformation, the next 10 years should not focus on advancing a single or limited set of solutions. Instead, Rhode Island should ensure that it is making progress, regardless of which solution (or mix of solutions) ultimately prevails. As illustrated in Figure ES 4, a policy framework for the next 10 years should involve five elements: **Ensure**, **Learn**, **Inform**, **Enable**, and **Plan**.

As an initial step to **ensure** decarbonization, improving the energy efficiency of buildings will provide several immediate benefits. By reducing heat needs, it will reduce greenhouse gas emissions, regardless of what heating technology is utilized (and to the extent heating is electrified, improved building efficiency will reduce heating's impact on electric loads). Importantly, cost-effective energy efficiency measures will reduce the total cost of heating, which will mitigate any potential increase in the cost of providing heat with decarbonized solutions. Finally, existing efficiency programs provide an effective program delivery network that can support the state's expanded heating-sector-related decarbonization efforts.

A second key policy element that will ensure progress towards decarbonizing the heating sector is enacting a set of technology-neutral measures that will reduce the carbon intensity of all energy sources used for heating – electricity, gas, oil, and propane – over time. Such measures may include renewable electricity requirements, carbon pricing or cap and trade policies, renewable fuel or heating standards, or other approaches. Complementary fuel-neutral policies include continued and increased efforts to improve the energy efficiency of Rhode Island's existing buildings, while also tightening the efficiency requirements for new construction.

Rhode Island must emphasize **learning** over the next decade, given the large uncertainties about

Ensure	Increase efficiency and reduce carbon content of all fuels to zero over time – ensures progress no matter which technologies are used
Learn	Data collection, R&D, pilot projects to understand technologies, infrastructure, and customers
Inform	Educate stakeholders – customers, installers, policymakers – about pros and cons of options, system interactions, etc.
Enable	Facilitate deployment with incentives; target natural investment opportunities; align regulations, rules, and codes; expand workforce
Plan	Expand planning horizon; develop long-term, high-level contingency plans now (do not commit yet) and use to guide near-term policy

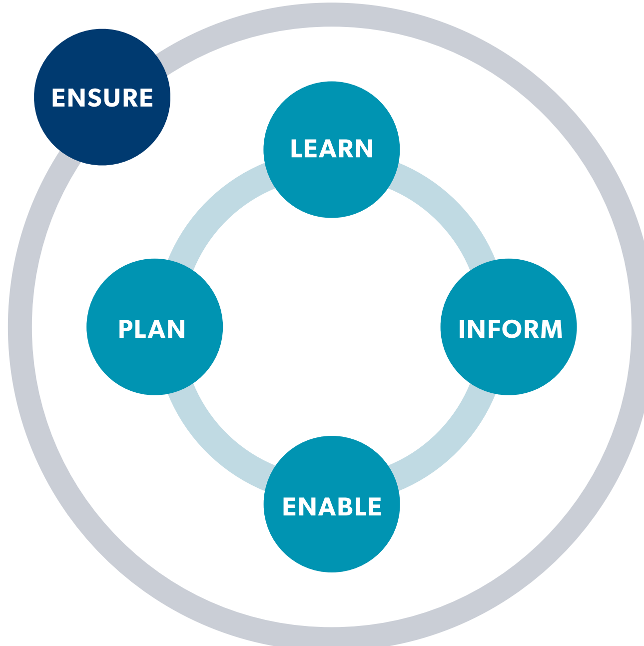


FIGURE ES 4: THEMES TO GUIDE EARLY POLICY RECOMMENDATIONS

both general and state-specific factors related to each of the decarbonized solutions and their implementation. Learning strategies should use pilot and demonstration projects, targeting state-specific issues or in collaboration for more general issues. At a minimum, learning policies should include:

- Information gathering to enable better incentive targeting (such as information on the type and age of heating-related equipment in the state)
- Proper research and development targeting Rhode Island-specific issues
- More general information in collaboration with other states or organizations

Rhode Island must **inform** key stakeholders, including consumers and the building trades, about the technical and economic issues related to decarbonized heat solutions that will require significant efforts to improve information level and flow. Potential policies in this area include broad information campaigns about the available solutions, including their pros and cons; publicly visible demonstration projects; developing training and certification programs for installers; and making information about qualified and experienced installers available to consumers.

Policymakers will need to enact several additional strategies to **enable** a heating sector transformation. These include policies that identify and address the implementation barriers, which may take the form of incentives to consumers and businesses designed to overcome both overall cost and especially first cost barriers, such as the high upfront cost of heat pumps. In addition, Rhode Island should realign its regulatory frameworks. Examples include removing existing incentives that favor gas system expansion, reconsidering rate structures for both electricity and gas, and exploring ways to integrate the regulatory treatment of National Grid's gas and electric businesses.

Another important enabling policy principle relates to identifying and capitalizing on "natural investment opportunities" where decarbonized solutions may be implemented at a lower cost and with less disruption by coordinating with other work being done on the infrastructure or building. Examples include instances where natural gas or electricity infrastructure is being upgraded or replaced, buildings undergoing deep renovations, or existing heating equipment that needs to be replaced as it approaches the end of its useful life. Policies that enable progress can also target existing codes, rules, etc. that may inadvertently create barriers to deploying decarbonized heating solutions that are otherwise attractive. Finally, enabling policies should identify and mitigate instances where heating decarbonization could impose undue burdens on vulnerable populations.

Planning will also be important. Changes to current planning approaches and some specific planning efforts will need to be part of the heating transformation strategy. In general, planning efforts should consider a long time horizon – 2050 or beyond – even if a typical planning exercise might only cover the next 10 years. This will allow Rhode Island to plan for the magnitude of changes needed to decarbonize the heating sector by mid-century, and account for the long lives of most heating-related infrastructure – buildings; pipelines; electric transmission and distribution equipment; GSHP ground loops; and even furnaces, boilers, and heat pumps themselves.

Also, some specific planning efforts will be necessary. An example is planning for the expansion of the electric distribution grid. Significant new electric loads are likely to come online over the next several decades, not just for heat but also for EV charging. This provides an opportunity to better understand the tradeoffs between "future-proofing" the grid by anticipating additional future demands, vs. planning only for near-term demands, which may lead to a series of smaller upgrades that could ultimately cost more. Similarly, even ahead of any clarity about the long-term role of the gas distribution system, developing plans for how the gas system might be altered to accommodate reduced gas use for heating, and whether there may be ways to do it more economically, will help inform the decisions that Rhode Island must undertake over the next few decades.

This report identifies several important technical issues that will affect the transformation of the heating sector. These include the potential impacts of electrified heat on the power sector, and the future role of the gas system and how reduced gas delivery volumes could affect it. These insights support an economic analysis of the different pathways to decarbonize heating – using renewable fuels with heating infrastructure similar to today's, or alternatively, electrifying heat with GSHP or ASHP.

That analysis showed that there is substantial overlapping uncertainty about the future economic attractiveness of the decarbonized solutions – regarding the long-run cost of renewable fuels (which is likely to be substantially above the current cost of fossil fuels), as well as the cost of heat pumps themselves and the clean electricity to power them. Because of these overlapping uncertainties, it is not possible to identify a clear winner among the technologies. However, it appears that decarbonized heat is likely to be somewhat more costly than natural gas heat is today, and potentially comparable with oil or propane. Still, overall consumer expenditures on energy in a fully decarbonized economy may be roughly comparable to today's costs.

This has several policy implications for driving a heating sector transformation over the next several decades. Policy approaches should support enabling early progress on decarbonization – by pursuing energy efficiency to reduce heat needs, and by decarbonizing all the energy sources used for heating – both fuels such as gas and oil, and also electricity to power new electrified heating systems. Beyond this, policies should support both the learning and informing stages, to begin to address the uncertainties, collect information that will be necessary for the transformation, and ensure a widespread understanding of the solutions and their implications. Regulatory changes can enable the transformation, addressing barriers and facilitating progress on any or all of the pathways. Policies that create structures to identify and capitalize on natural investment opportunities will also enable the transformation.

Broadening planning approaches for both the electric and gas systems will allow policymakers to consider longer time horizons consistent with the natural lives of heating infrastructure components and the timeframe and magnitude of the transformation. While it seems counterintuitive, Rhode Island must develop action plans knowing that it might not ultimately need them, since developing the plans will inform decisions about whether to implement them. The transformation of the heating sector over the next several decades will be a major undertaking, but it is achievable with early and sustained policy focus.

EJW-4

Introduction and Background

In line with well-established consensus in the scientific community and international commitments such as the Paris Accord, Rhode Island has committed to deep economy-wide decarbonization by 2050. Specifically, the Resilient Rhode Island Act establishes a goal of 80% economy-wide greenhouse gas ("GHG") emissions reductions relative to a 1990 baseline by 2050 with interim targets of 10% reductions by 2020 and 45% reductions by 2035.[1] Also, Executive Order 17-06 from June 12, 2017 reaffirms Rhode Island's commitment to the principles of the Paris Climate Agreement.[2]

As part of this commitment, Governor Gina M. Raimondo's Executive Order 19-06 requires the DPUC and OER to lead a Heating Sector Transformation and provide a corresponding report with recommendations to the Governor on or about April 22, 2020.[3] To fulfill this requirement, the DPUC and OER asked The Brattle Group to analyze options for decarbonizing Rhode Island's heating sector and the results of this analysis are presented in this report.

The report is the result of independent analysis conducted by The Brattle Group, supported by an extensive stakeholder effort involving interviews and meetings with over 20 individual stakeholder organizations, as well as three public workshops held to share information, present intermediate results, and collect feedback.[4] This report is accompanied by a **Technical Support Document**, which provides more detail on the modeling and assumptions underlying its findings. While this report addresses what would be needed to achieve the decarbonization goals of the heating sector, it is not intended to comprehensively address the aggregate costs of decarbonizing, how those costs would be funded, or the time period over which the transformation is achievable, given the practical challenges that will inevitably need to be addressed.

This initiative to evaluate heating sector transformation comes amid the COVID-19 pandemic,

1 Resilient Rhode Island Act of 2014 – Climate Coordinating Council, Chapter 42-6.2. http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM

2 "Executive Order 17-06, Reaffirming Rhode Island's Commitment to the Principles of the Paris Climate Agreement," State of Rhode Island and Providence Plantations. June 12, 2017. http://www.governor.ri.gov/documents/orders/ExecOrder_17-06_06112017.pdf

3 "Executive Order 19-06, Heating Sector Transformation to Ensure Reliability and Protect Against Climate Change," State of Rhode Island and Providence Plantations. July 8, 2019. http://www.governor.ri.gov/documents/orders/Executive%20Order%2019-06.pdf

4 Three public workshops were held during the course of this project – two in-person meetings and one webinar-based presentation. Each workshop attracted more than 60 registered participants and included opportunities for stakeholder Q & A. Written public comments were also accepted via email.

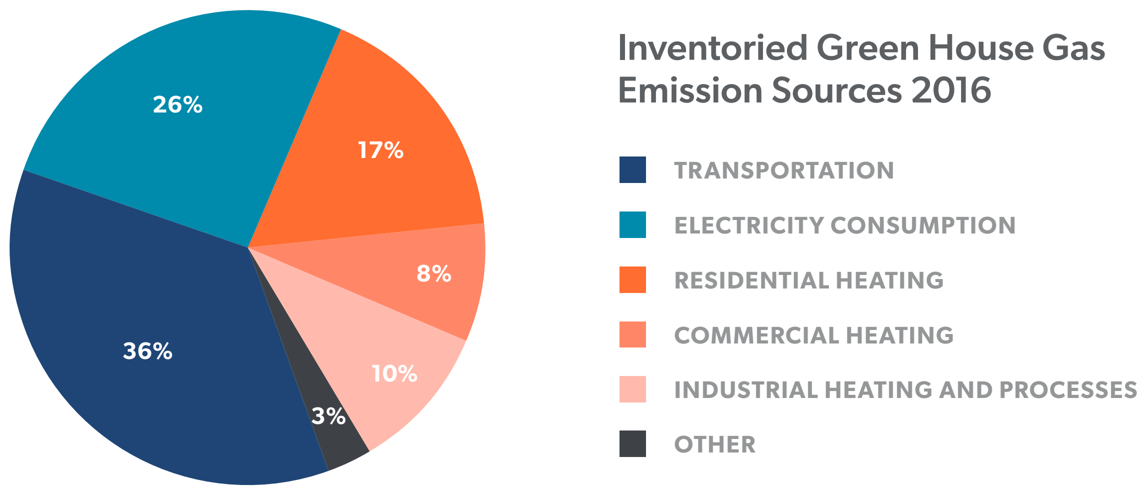


FIGURE 1: COMPOSITION OF RHODE ISLAND GHG EMISSIONS

Source: Rhode Island Department of Environmental Management, Rhode Island's 2016 Greenhouse Gas (GHG) Emissions Inventory Update, EC4 Meeting, September 12, 2019.

which has disrupted much of the state, national and international economy, including the energy sector. While this disruption will doubtless cause many short-term impacts throughout the economy, including the heating sector, we assume that these impacts will be relatively short-term in nature and will not fundamentally alter the long-term, multi-decade needs and goals for decarbonizing the economy. Indeed, climate change is a problem that will still exist and will need to be addressed long after the pandemic has been resolved.

This analysis also comes in the wake of the gas service outage that occurred on Aquidneck Island on January 21, 2019.[5] While this report addresses heating sector transformation in the context of climate change, it may also have implications for the future of heating service reliability. For most Rhode Island customers, heating currently depends strongly on the interstate and local gas distribution systems to provide natural gas on the coldest days, when gas demand is highest and the gas system is most constrained. Electrifying parts of the heating sector would reduce this reliance on the gas system, but would create a new reliance on the electric transmission and distribution infrastructure, which might become similarly constrained on those coldest winter days.

The effort to transform the Rhode Island heating sector occurs against the backdrop of concerns about climate change related risks and resulting state-level greenhouse gas reduction targets and efforts. Figure 1 shows the composition of Rhode Island's GHG emissions as of 2016. As shown, heating related emissions (including industrial emissions) represent 35% of statewide emissions and are roughly equal to transportation emissions. Hence, even if all non-heating sectors were to become completely emissions-free by 2050, the heating sector would still need to be significantly decarbonized to meet the current GHG emissions reduction goals.

More likely, some emissions in the transportation sector, as well as industrial process (and likely some heating related) emissions will be very difficult to eliminate. Consequently, even if the State is successful

5 Summary Investigation into the Aquidneck Island Gas Service Interruption of January 21, 2019, October 30, 2019

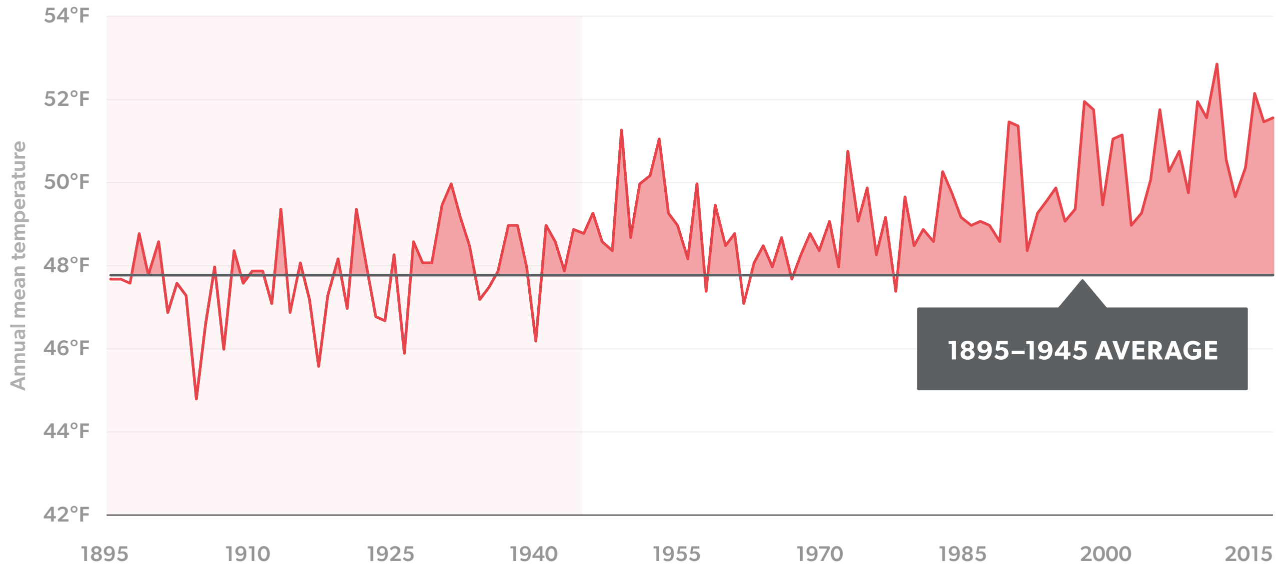


FIGURE 2: ANNUAL MEAN TEMPERATURES IN RHODE ISLAND (1895–2018)

Source: NOAA National Centers for Environmental Information, Climate at a Glance: Statewide Time Series, published January 2020, retrieved on February 2, 2020 from https://www.ncdc.noaa.gov/cag/

in fully decarbonizing the electricity sector, even full decarbonization of the heating sector would require very significant reductions in the remaining emitting sectors to achieve 80% GHG emissions reductions by 2050. This is not taking into account uncertainties about the contributions of emissions from methane leaks and/or non-energy emissions, such as land-use changes, which were not included in the State's most recent draft GHG emissions inventory.

Also, as recognized by Governor Raimondo's recent executive order to achieve a 100% renewable electricity supply in Rhode Island by 2030[6] and similar efforts to accelerate decarbonization goals relative to 80% reductions by 2050, evolving science and evidence related to climate change may require an acceleration of decarbonization relative to current policy goals.

For these reasons, this report identifies and evaluates various options and solutions for full decarbonization of the state's heating sector, recognizing that achieving full decarbonization may be very difficult for some heating applications and that deeper decarbonization in the other emitting sectors or the emergence of negative emissions technologies (including land-use measures that could increase GHG sequestration to offset some emissions) may create room for some remaining emissions in the heating sector.

However, recognizing the uncertainties described above, developing pathways for a transition to a fully decarbonized heating sector is both in line with existing policy goals and provides insurance value in case either non-heating emissions reductions are harder or more expensive to achieve or if GHG emissions reductions need to be deepened.

Finally, this report assumes that addressing heating sector emissions will remain vital even if climate change is expected to result in increases in average annual temperatures. As **Figure 2** shows, average Rhode Island temperatures have already increased by

6 Executive Order 20-01, Advancing a 100% Renewable Energy Future for Rhode Island by 2030, January 17, 2020

more than 3 degrees Fahrenheit since the beginning of the 20th century.

There is also some evidence that higher average temperatures result in warmer average winters in the Northeast,[7] which would have a tendency to lower the overall energy needed to heat Rhode Island homes and businesses. On the other hand, heating demand is greatest during the coldest days of the year and, somewhat counterintuitively, there is some evidence that suggests that climate change may increase temperature extremes in New England both in the summer and in the winter, leading to continued (and perhaps more intense) periods of extremely cold temperatures.[8] Since our energy systems are designed to ensure a reliable supply of energy during essentially all expected conditions, the possibility that winter temperature extremes will remain largely unchanged or worsen even as the state's average temperatures increase therefore needs to be considered when developing a heating sector transformation strategy for Rhode Island.

7 See for example USA Today, The Northeast warms ahead of rest of USA: 'Our winters now are not like our winters before (https://www.usatoday.com/story/news/nation/2019/12/25/climate-change-northeast-warming-faster-united-states/2743119001, accessed February 2, 2020)

8 See for example Axios, The polar vortex splits, sending frigid air howling into the U.S., Europe, January 16, 2019 (https://www.axios.com/polar-vortex-means-winter-is-coming-to-east-coast-and-europe-5fb653fd-1664-41aa-9a99-549e2541d89a.html, accessed February 2, 2020)

EJW-4

Overview of the Rhode Island Heating Sector and Decarbonization Solutions

THE RHODE ISLAND HEATING SECTOR

Rhode Island's heating sector is comprised of a variety of uses and environments. Heat is primarily used for space heating and water heating in the residential and commercial sectors (with smaller amounts for cooking, clothes drying, etc.), and in various industrial applications, primarily as process heat. At the building level, heating occurs in single- and multi-family residential buildings, in a wide variety of commercial buildings and, finally, in a number of industrial applications. Industrial heating applications include a multitude of different process heat uses and therefore are significantly different from residential and commercial space and water heating. There is little detailed information available regarding the heating related energy use in Rhode Island's industrial sector.

Figure 3 shows the shares of total energy consumption in the residential, commercial, and industrial sector, respectively. Of total energy use in the state, the residential sector represents roughly 50% of total energy use, the commercial sector one-third, and the industrial sector the remainder. The share of energy

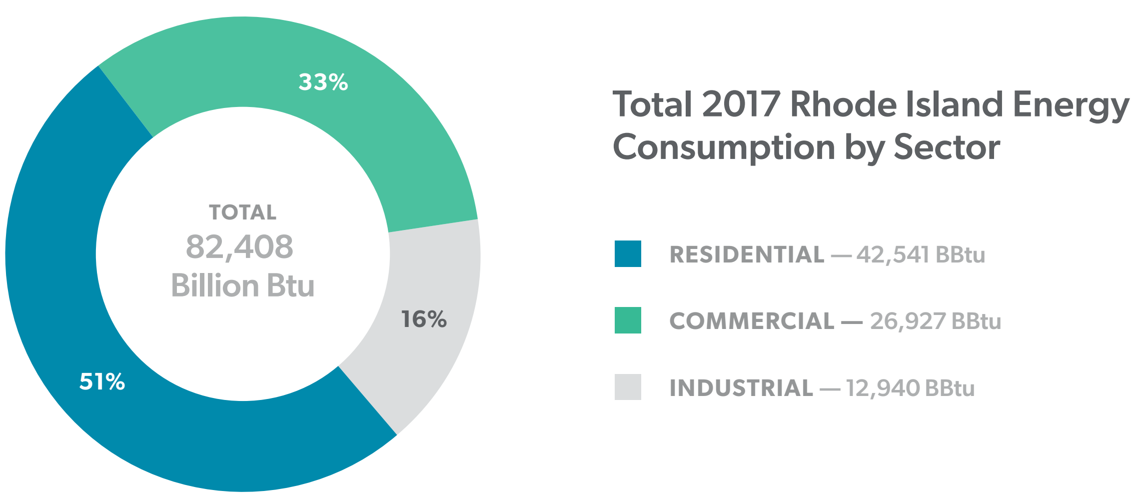


FIGURE 3: TOTAL 2017 RHODE ISLAND ENERGY CONSUMPTION BY SECTORS

Source: Buro Happold Analysis.

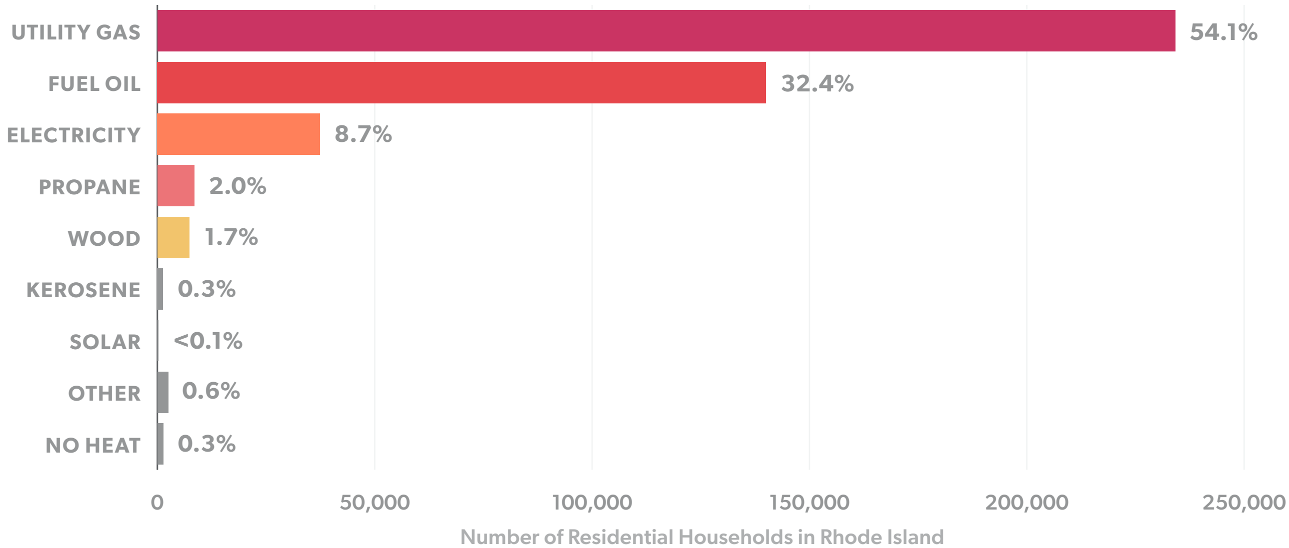


FIGURE 4: HEATING SOURCE FOR RHODE ISLAND RESIDENTIAL CUSTOMERS

Source: Meister Consultants Group, Rhode Island Renewable Thermal Market Development Strategy, prepared for the Rhode Island Office of Energy Resources, January 2017.

use by type (heating, cooling, other) likely differs significantly by sector, with the share of heating in total energy use likely the greatest for the residential sector, followed by the commercial sector. Overall, this implies that transforming the heating sector in Rhode Island will be impossible without a significant focus on the residential and commercial sectors. While decarbonizing the entire heating sector in Rhode Island will be impossible without also addressing industrial heat, which includes space and water heating as well as various types of process heat, decarbonizing process heat will require more tailored approaches.

Figure 4 provides an overview of the composition of heating in New England. **Figure 5** provides additional insights into how total heating-related energy use is distributed across various types of residential and commercial buildings in the state. As shown, single family residential buildings represent close to 60% of all heating-related energy consumption in the state. Consequently, the analysis in this report focuses particularly on this building type. Larger buildings, such as multi-family and office buildings, are also important consumers of heating-related energy, and are considered separately.

Figure 6 illustrates that the large majority of residential buildings in Rhode Island were built before 1980 and, hence, are relatively old. With few new building permits issued each year,[9] it is clear that transforming the heating sector in Rhode Island must focus primarily on existing buildings. It also provides information on the heating fuel type by building age, confirming that natural gas is the dominant source of heating across buildings of all ages, followed by heating oil, which is a close second for buildings constructed between 1950 and 1980. The fact that the majority of the residential housing stock is old with existing heating systems designed for fossil fuels highlights the practical challenges Rhode Island may face in converting the heating systems in such a large number of buildings over the next few decades.

9 In 2019, 1,138 building permits for new residential housing were issued. (https://fred.stlouisfed.org/series/RIBPPRIV). In 2018, the number was 1,192. At this rate, less than 40,000 new housing units will be added by 2050, i.e., less than 10% of the current number of housing units.

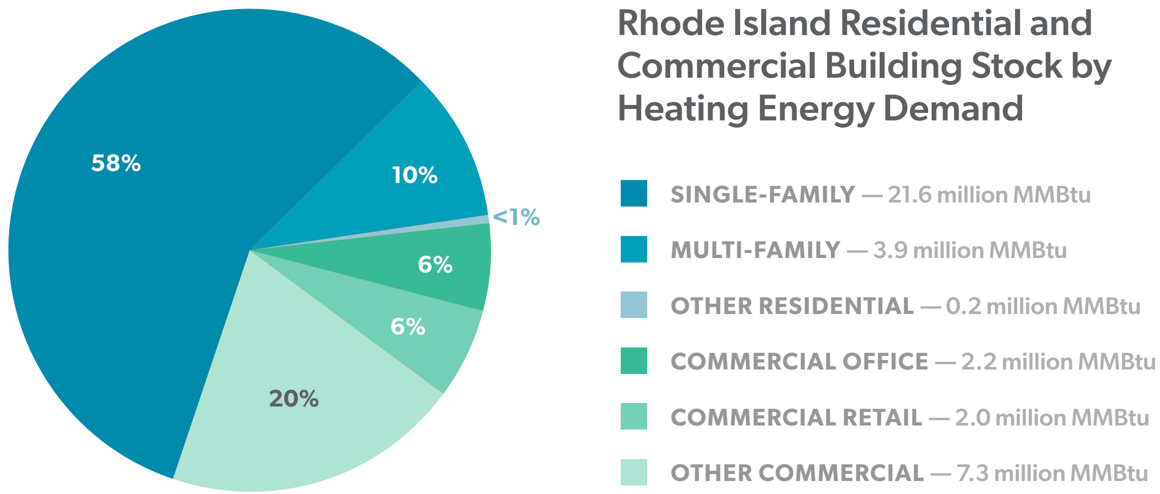


FIGURE 5: RESIDENTIAL AND COMMERCIAL BUILDING STOCK BY HEATING ENERGY DEMAND

Source: Buro Happold Analysis.

Figure 7 shows similar summary descriptions of Rhode Island's commercial building stock, by building type and square footage. This is the backdrop against which the rest of this report assesses decarbonization solutions for the Rhode Island heating sector.

PRIMARY HEATING APPLICATIONS IN RHODE ISLAND

Heating is used for three broadly defined purposes: space heating, water heating and process heating. Secondary applications include cooking, clothes drying, etc. Within the residential and commercial sectors, which together represent 84% of total heating energy demand in the state, space and domestic water heating represent the largest share of total heating related fuel demand.

Figure 8 indicates that among fuel-based heating, space heating in New England represents more than three-fourths of total energy use and that all uses other than space or water heating represent only four percent of total energy demand.[10]

Figure 9 provides the same summary for the commercial sector and indicates that while other heating uses are more prevalent in the commercial sector (notably cooking), the share of space and water heating in the commercial sector also exceeds 80%.

Because of the dominance of space heating in total heating demand, transforming the Rhode Island heating sector must focus on space and, to a lesser extent, domestic water heating.

For smaller buildings in Rhode Island, such as single family homes, small multi-family buildings, and some small commercial buildings, primary heat is typically provided in one of a few ways. Fuel can be burned in a furnace to heat air, which is then distributed through the building by a forced hot air system consisting of a blower fan and ductwork. Alternatively, fuel is burned in a boiler to heat water in a hydronic system, which pumps the hot water through pipes to distribute the heat to radiators (sometimes boilers produce steam

10 These figures exclude households using electricity for space and domestic water heating, but it is likely that the respective shares of each heating type are similar. Also, these figures represent New England averages, which are likely close approximations of the relevant shares in Rhode Island.

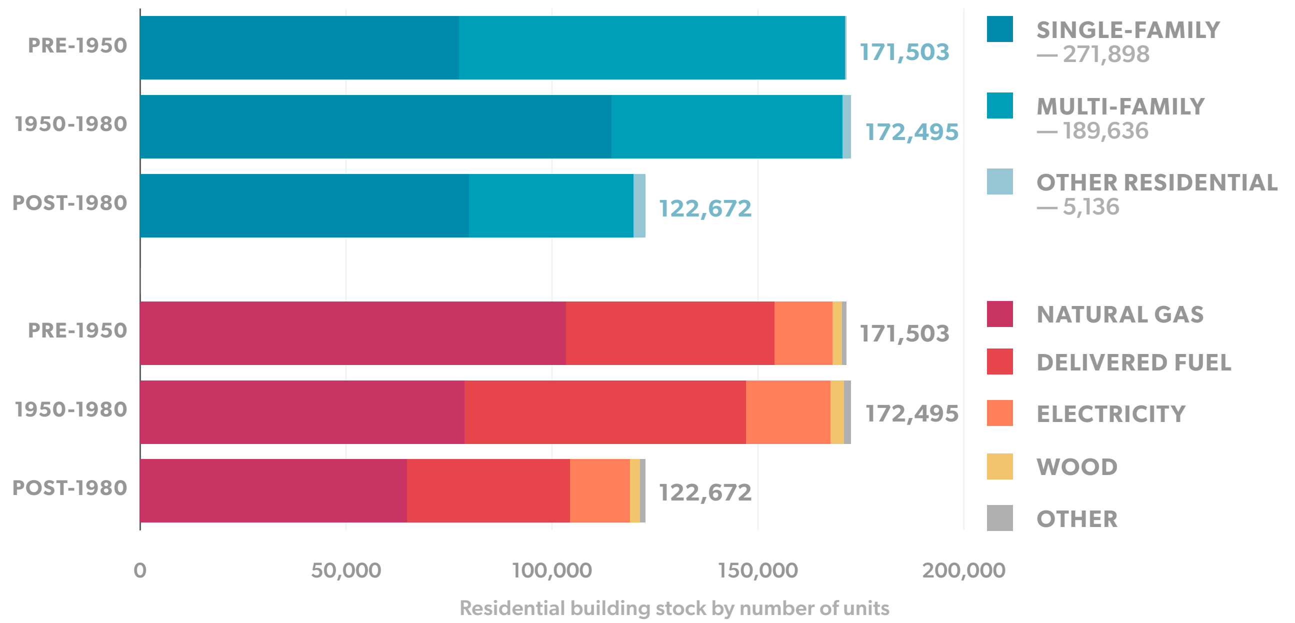


FIGURE 6: RHODE ISLAND RESIDENTIAL BUILDING STOCK BY AGE, HOME TYPE AND FUEL

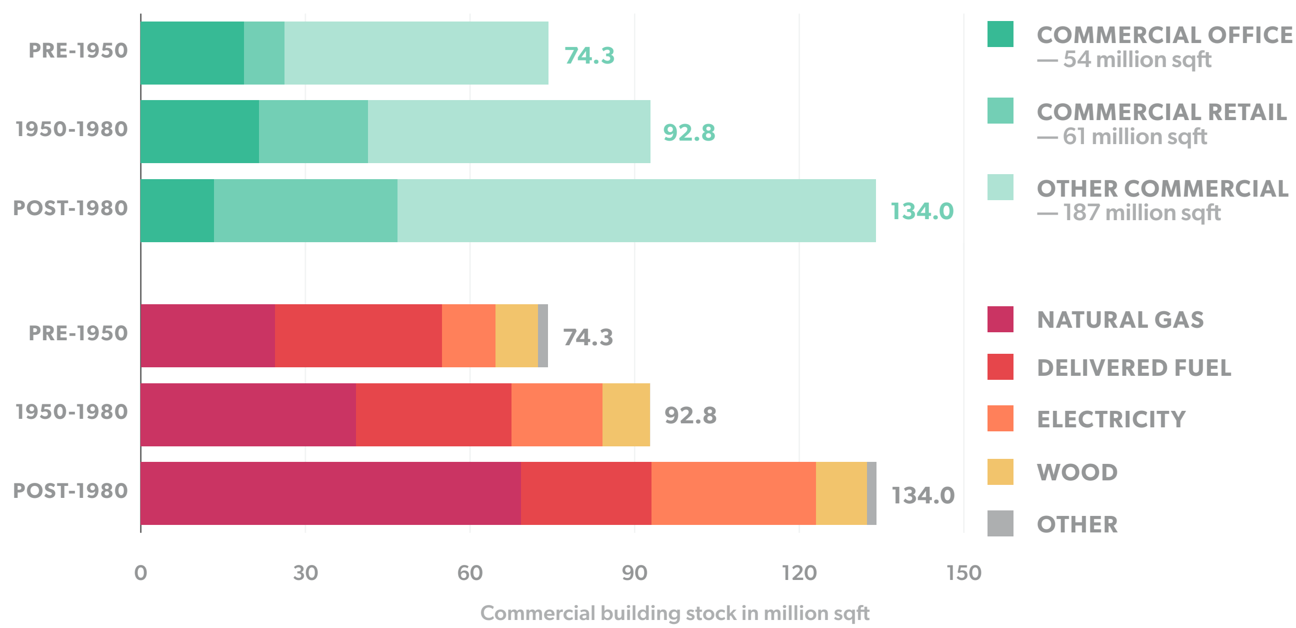


FIGURE 7: RHODE ISLAND COMMERCIAL BUILDING STOCK BY BUILDING TYPE, SQUARE FOOTAGE AND FUEL

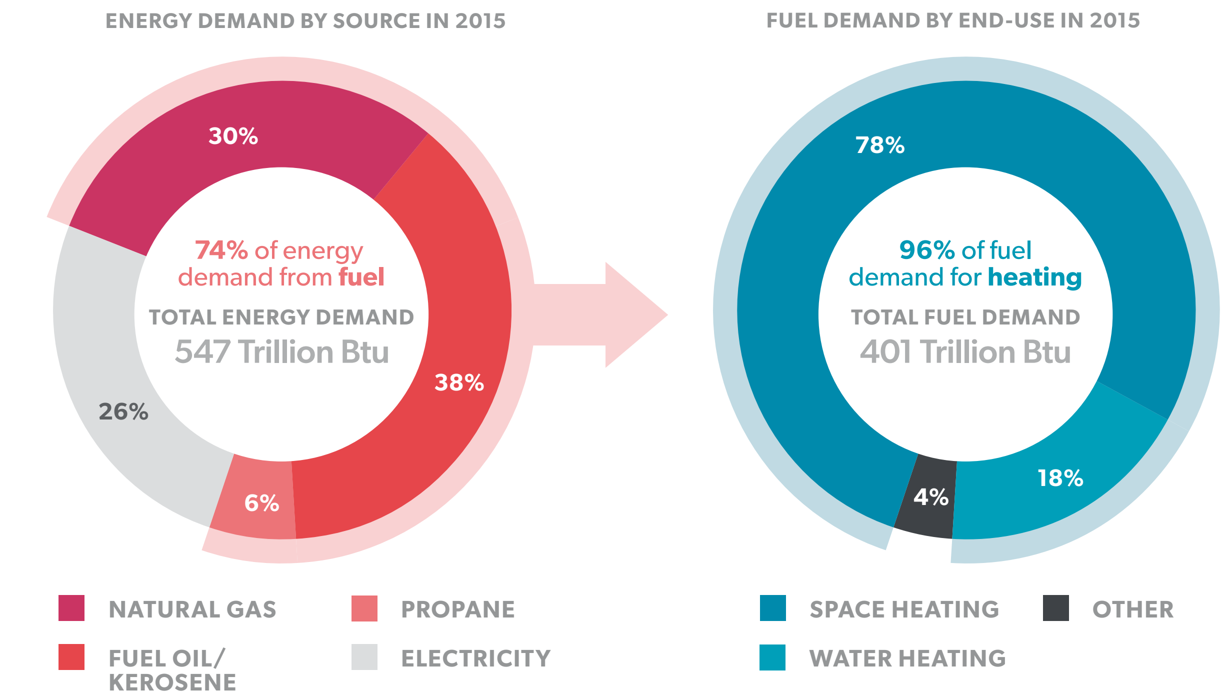


FIGURE 8: ENERGY DEMAND IN NEW ENGLAND FROM HEATING FUELS OTHER THAN ELECTRICITY (RESIDENTIAL SECTOR, 2015)

Source: EIA 2015 RECS Survey Data.

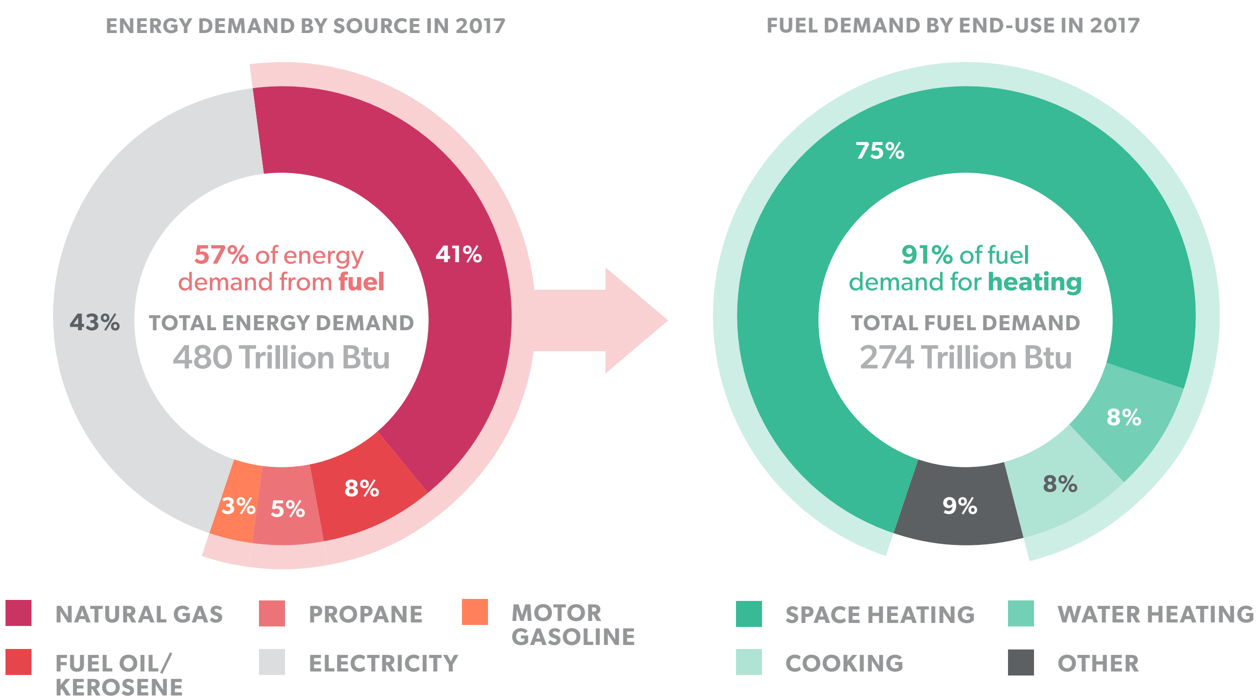


FIGURE 9: ENERGY DEMAND IN NEW ENGLAND FROM HEATING FUELS OTHER THAN ELECTRICITY (COMMERCIAL SECTOR, 2017)

Source: AEO 2019 and EIA 2012 CBECS Survey Data.

Note: "Other" includes office equipment, cooling, refrigeration, manufacturing, and electricity generation.

that circulates through steam pipes to radiators). With both furnaces and boilers, the fuel can be natural gas, heating oil or propane. Less frequently, heat is provided by electricity, usually with electric resistance (baseboard) heat, and rarely, for now, using a heat pump, which works much like an air conditioner (and can be used either in heating or cooling mode). A few buildings are heated by other means, such as wood stoves and solar.

Figure 10 shows an indicative comparison of the costs of the predominant fossil heating options, for a representative single-family home in Rhode Island with average energy use for heating.[11] This type of comparison will be used again later in this report to illustrate the relative costs of decarbonized heat solutions as well. The shades of orange at the bottom of each bar depict the annualized cost of the capital equipment required – furnace or boiler that must be replaced periodically in the case of fossil heat; as shown below, the equipment needs for some of the decarbonized heat solutions are different and more involved. The shades of blue above represent the operating costs of the heating systems – primarily the cost of the input energy which is fuel for most current systems, or electricity. Currently, natural gas is the least costly option for heating in Rhode Island with an overall cost of about $2,700 per year for a representative existing detached single-family home, because the fuel cost of natural gas is much less than oil ($3,500) or propane ($4,300). Heating with electric resistance heating is the most expensive current heating solution ($5,500 per year). Projections for 2050 costs are also provided, with future fuel costs based on the AEO fuel price projections,[12] and including assumed improvements in furnace and boiler efficiencies, particularly for natural gas-fired heating.[13] The gray area at the top of each bar represents the cost of carbon emissions at $75/metric ton CO_2 (based on the current implicit carbon value used to evaluate efficiency investments) for both 2020 and 2050, though by 2050, the relevant carbon price may be higher, and may in fact become part of the fuel prices paid by consumers. (no carbon cost is associated with electric heating in 2050 since it is assumed that electricity will be carbon-free by then, in line with Rhode Island and regional policy goals).[14] The relative ranking of the standard heating technologies remains unchanged, with natural gas heating still being the least costly and electric resistance heating still the most costly.

The demand for heating in larger buildings (e.g., multi-family apartment buildings and large commercial buildings such as office towers) of course tends to be higher in total, though the heat need usually grows less quickly than the building's square footage (i.e., as building size increases, the outer surface area of the building through which heat is lost grows less quickly than the square footage). These larger

11 The economic analyses here are expressed in real (i.e., inflation-adjusted) 2018 dollars.

12 U.S. Energy Information Administration, Annual Energy Outlook 2019, Table 3: Energy Prices by Sector and Source.

13 Caution should be used in interpreting the 2050 projections, since the fuel price projections by the AEO underlying these values are probably not consistent with the decarbonized future considered by Rhode Island and other New England states.

14 Estimates of the "social cost of carbon," measure of the value to society of avoiding one ton of CO_2 emissions, tend to increase over time since the value is equivalent to the value of avoided future damages caused by GHG emissions and as the time when more serious damages due to GHG emissions are expected is closer to the present in 2050 than today. For example, until 2017, the U.S. estimated the social cost of carbon to be $42/ton in 2020 (expressed in constant 2007 dollars and using a 3% discount rate), rising to $69/ton by 2050. Using a 2.5% discount rate, the value increases from $62/ton in 2020 (which represents approximately $75/ton in 2017 dollars) to $95/ton (or $115/ton in 2017 dollars) in 2050. See Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866; Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, August 2016. Electricity prices for 2050 reflect the projected cost of a decarbonized electricity supply.

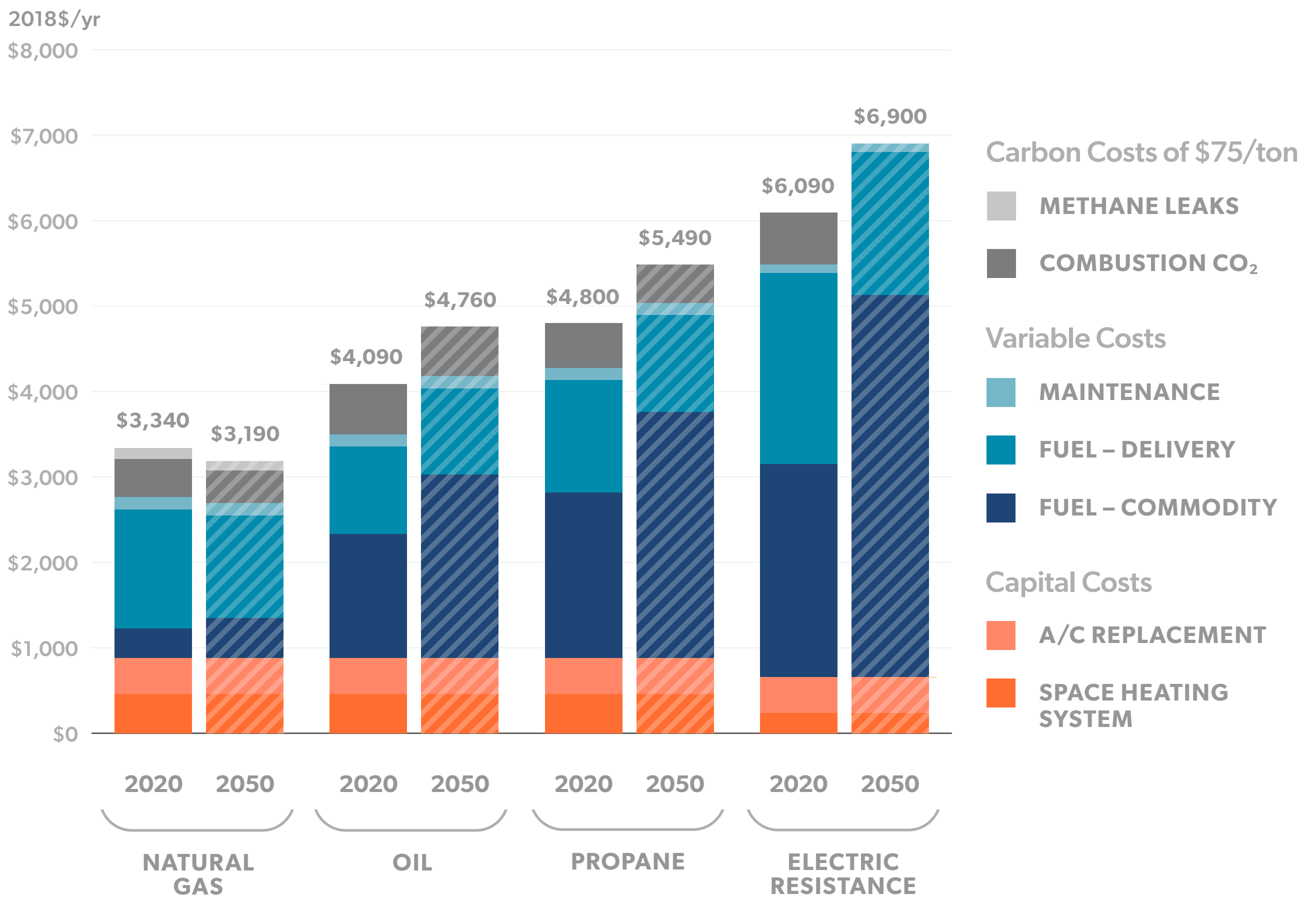


FIGURE 10: ANNUALIZED COST OF CURRENT HEATING TECHNOLOGIES, SINGLE-FAMILY HOME 2020 AND PROJECTED 2050 (2018$)

Notes: Fossil fuel prices for 2050 are based on Annual Energy Outlook projections. Electricity price for 2050 is based on the cost of an assumed carbon-free electricity supply for New England that would be able to supply traditional electricity uses plus electrification of light-duty vehicles.

buildings can have different types of heating/cooling systems, particularly regarding the internal distribution systems within the building. In addition to needing less heat per square foot, larger buildings typically need some cooling even in the heating season. But larger buildings are highly idiosyncratic in terms of their heating systems, perhaps even more so than small buildings. They typically combine large boilers that provide heat with chillers and cooling towers for cooling, and use hydronic (water-based) distribution systems within the building to move the heat and cool to where it is needed. Fans or forced air systems are used to move the heat or cool from the hydronic system into the various building spaces that require space conditioning. Still, despite the differences in their heating systems, the relative economics of heat in large buildings is similar to that for small buildings, since both are driven by the relative costs of the different available fuels and the heating equipment

DECARBONIZATION SOLUTIONS FOR RHODE ISLAND

Depending on the heating application and building type, there are several options to decarbonize heating, some of which are substitutes while others can be used in combination. This section discusses the various solutions at a high level. The 2017 Rhode Island

Space and water heat Several primary solutions are feasible across many applications/buildings	**Decarbonized Fuel** Supply may be limited from less-costly sources	**Renewable gas/power-to-gas (P2G) for gas customers** • Landfill gas, anaerobic digesters, gasification, synthetic gas
		Biofuel or power-to-liquids (P2L) for most other customers • Biodiesel, ethanol, synthetic fuels
	Heat Pumps	**Air source heat pump (ASHP)**
		Ground source heat pump (GSHP) • Including GeoMicroDistric
Industrial heat	• May be more specialized (e.g., high-temp) • May require (decarbonized) fuel, including hydrogen	

TABLE 1: DECARBONIZATION SOLUTIONS

Renewable Thermal Market Development Strategy report ("Meister Report")[15] provides a more detailed technical description of many of these technologies. Further information is provided in the **Technical Support Document** accompanying this report. Very broadly, apart from energy efficiency measures, which must play an important role independent of what heat solution is chosen, the decarbonization solutions fall into the categories outlined in **Table 1**.

As the table shows, the two primary pathways include decarbonizing fuels and electrifying heat via heat pumps. The relative attractiveness of these paths has been studied in a variety of contexts and geographies.[16] These and similar studies provide an important background for the analyses in this report as a basis for developing a heating transformation strategy for Rhode Island.

1. The Role of Energy Efficiency

One of the most obvious approaches to decarbonizing the heating sector is to lower the overall need for heat, which can be achieved through increasing the efficiency of buildings – primarily via weatherization and/or more efficient heating equipment for existing buildings, and via building codes requiring better energy performance for new buildings.[17] Cost-effective energy efficiency measures will reduce GHG emissions, and will reduce the total cost to customers, mitigating the potentially higher cost of decarbonized heat. Of course, energy efficiency efforts targeting

15 Meister Consultants Group, Rhode Island Renewable Thermal Market Development Strategy, prepared for the Rhode Island Office of Energy Resources, January 2017

16 See for example KPMG, 2050 Energy Scenarios, July 2016; DNV-GL, The Potential Role of Power-to-Gas in the e-Highway 2050 study, 2017; E3, The Challenge of Retail Gas in California's Low-Carbon Future, Final Project Report, California Energy Commission, CEC-500-2019-055-F, December 2019; E3, Deep Decarbonization in a High Renewables Future, California Energy Commission, CEC-500-2018-012, June 2018

17 Switching to heat pumps has also been supported under existing energy efficiency programs, but these are discussed below as a separate decarbonization pathway.

heating demand and electricity demand already play an important role in Rhode Island through the energy efficiency programs implemented by state utilities.[18] Existing efficiency programs provide an effective program delivery network that can be accelerated to further reduce the energy needs for heating (and cooling) in existing and new buildings, and can also be expanded to support providing decarbonized heating systems. Heating related energy efficiency measures can be very cost-effective in new buildings. By designing a building to be energy efficient from the earliest stages, its need for heat (as well as other forms of energy) can be reduced dramatically for very modest initial cost, often just a few percent of the initial cost.[19] Specifically, very tight building envelopes, insulation, efficient windows, and efficient heating and cooling systems are often very cost-effective since they tend to require little or no incremental labor and only modest materials cost, and often pay back in two to three years.[20] However, even such easy and cost-effective measures are not always undertaken in new buildings, in part because they are not an integral part of traditional design approaches, complicated by the fact that the designer/developer does not typically pay the building's energy costs and thus has little direct incentive to reduce them. For these reasons, new building codes and standards, as well as energy disclosure requirements, are an important way to ensure that new buildings comport with the goals of decarbonizing the heating sector, causing the state's buildings to become more efficient as the building stock grows renewed and grows over longer time horizons. the fact that new construction will account for a small share of the buildings in Rhode Island by 2050, an effective heating transformation strategy must ensure that cost-effective efficiency measures for new buildings – likely primarily in the form of building codes – are also part of Rhode Island's heating transformation strategy. Cost-effective efficiency measures save money for customers, and even though the building stock turns over slowly (perhaps especially because it turns over slowly), ensuring that new buildings are efficient will protect Rhode Island customers in the long run.

However, since most of the existing Rhode Island building stock is quite old – almost 75% of residential buildings are over 40 years old – it is very likely that most of the buildings that will exist in 2050 have already been built. Therefore, transforming the heating sector will require a substantial effort to retrofit existing buildings, unless there is a substitute decarbonized fuel that can be used with the existing heating systems and appliances that utilize existing fossil fuels.[21]

Efficiency measures for existing buildings such as weather stripping, air sealing and attic insulation tend to be relatively low cost since they do not require intrusive interventions in the building. They have been shown to be cost-effective and are at the heart of Rhode Island's energy efficiency programs. Such measures have represented the bulk of "building envelope" related energy efficiency measures to date. For example, in the 2018 program year, National Grid's EnergyWise program resulted in over 3,700 weatherization measures implemented, carved out from over 10,000 customers that received an energy audit as part of the program. Counting the overall program expenses for the EnergyWise program, average costs per weatherization were just short

18 Rhode Island is home to three electric distribution utilities (National Grid, Block Island Utility District, and Pascoag Utility District, with National Grid serving the large majority of customers) and one gas distribution utility (National Grid).

19 See for example EPA, Rules of Thumb – Energy Efficiency in Buildings, p.2, which suggests an increase in building costs of 2-7% for green high-performance buildings relative to "normal" buildings.

20 See for example EPA, Rules of Thumb – Energy Efficiency in Buildings, p.2, which suggests a payback period for high performance buildings of 2 years, 2.1 years for libraries and 2.6 years for schools.

21 This report does not address how comprehensive retrofits of existing buildings would be funded.

of $4,200, with average participating customers contributing approximately $575.[22] However, these measures typically achieve only a moderate reduction of overall heating demand; in aggregate, they tend to reduce heating energy needs by 10-15%. Further reductions in heating energy needs require additional measures that have a higher cost and are more intrusive to the occupant of the existing structure.[23]

Heat energy savings of 40% or more are possible in existing buildings, but require “deep” retrofits with measures such as window replacement and adding insulation not only to attics, but also to exterior walls and floors. Such activities tend to be more disruptive and entail significant cost when retrofitting an existing building. The necessary interventions in an existing building also tend to be highly building-specific and, therefore, difficult to standardize.[24] Their cost can exceed $50,000 or even $100,000 for a residential home, with comparably high costs for most commercial buildings. Such deep retrofit measures have so far not been deemed to be cost-effective in existing buildings and face significant initial cost and implementation barriers.[25]

Looking forward, energy efficiency measures in existing buildings that are cost-effective today are even more likely to be so in the future. Implementing cost-effective efficiency measures reduces customer expenses for heating (and electricity) – particularly relevant at a time like the present when the COVID-19 pandemic is affecting the incomes of many local residents and businesses, but important in normal times as well. Energy efficiency will also need to play an important role in transforming the heating sector in the longer term. At present, National Grid is on pace to complete energy audits of essentially all residential buildings in the state by 2050. However, even though such measures are generally cost effective, only about one-third of residential customers who receive an energy audit also opt for these weatherization measures. Going forward it will be important to develop policies and incentives to improve this conversion rate so that cost-effective weatherization efforts reduce the need to provide decarbonized heat to the greatest extent possible. Energy efficiency programs may also be useful delivery mechanisms for heating transformation solutions such as deploying heat pumps where cost effective. In that case, future policy likely needs to focus on increasing conversion rates (the rate of adoption once cost effectiveness has been established, for example via an energy audit), since the extent of deployment of such solutions across the more than 400,000 buildings will depend critically on what fraction of customers adopt such solutions.

Beyond weatherization, there are also newer, technology-enabled energy efficiency measures that can provide additional heat energy savings. They include behavioral programs to encourage conservation, including those made possible through smart thermostats. At present it seems unclear what the net effect of simple weatherization

22 Calculated based on National Grid, 2018 Energy Efficiency Year-End Report, May 15, 2019, p.8 and Table E-3.

23 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.

24 There are efforts to develop standardized deep retrofit approaches to existing residential buildings. NYSERDA is currently in a phase of pilot project through the RetrofitNY program, leveraging efforts to develop standardized retrofits in the Netherland pioneered by EnergieSprong. (See https://energiesprong.org/country/new-york/ and https://www.greenbuildingadvisor.com/article/u-s-looks-to-europe-for-energy-retrofit-model)

25 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.

and such behavioral programs might be. Since smart thermostat penetration will likely increase over time, it is likely that more customers will at least have access to such programs. Beyond conservation, these programs also contribute to reducing demand peaks, which will help lower the cost of electricity in a fully clean power grid of the future.

Two other points need to be emphasized. First, cost-effective energy efficiency measures not affecting heating demand, but electricity demand instead, will likely be critical in enabling a successful heating sector decarbonization. By reducing the demand for electricity relative to what it would otherwise be, they will reduce the challenge of building a portfolio of electricity generating resources capable of supplying the state (and region) with 100% clean electricity. Second, by having been in place for many decades and having steadily improved over time, existing energy efficiency programs and their administration and delivery are likely a key delivery vehicle for implementing other heating related policies. The fact that current state incentives for heat pumps are delivered through existing energy efficiency programs is likely only the beginning of using and improving an existing delivery channel for many of the policies needed to transform the sector.

Recognizing the contribution of cost-effective weatherization on the costs of various decarbonization solutions for customers by 2050, the analysis below assumes that the combination of cost effective energy efficiency measures will lower the total heating requirements of a representative Rhode Island building by 15% and that the remaining (very significant) sources of heat must be decarbonized to achieve the state's decarbonization targets. The two primary pathways for decarbonizing heat in Rhode Island are discussed next – electrifying via heat pumps (with a decarbonized electric sector) and decarbonizing the heating fuel.

2. Decarbonized Electrification with Heat Pumps

Using electricity to heat homes is not new. In fact, it is the primary heat source for about 9% of Rhode Island's residential customers and 13% of commercial square footage.[26] Currently, most of the electric heat in Rhode Island is electric resistance, but an increasing share is using electric heat pumps, particularly in the commercial sector. Heat pumps are based on a technology that is well understood and widely deployed – it is the same approach used in refrigerators and air conditioners. In contrast with furnaces and boilers which generate heat, a heat pump moves heat – from outside the building to the inside (or the reverse in cooling mode). With this approach, heat pumps take advantage of energy available in the environment (even cold outdoor air in the winter contains significant heat energy) and consequently can achieve efficiencies well above 100%. That is, for each unit of electric energy consumed, they provide more than one unit of heat to the building.

There are many types of heat pump applications, but they can be grouped into two broad categories: Air Source Heat Pumps (ASHP) and Ground Source Heat Pumps (GSHP), with the primary distinction being the outside heat source used (or heat sink in cooling mode). ASHPs use outside air as a source for heat, with a fan to move the air across a heat exchanger. The heating efficiency of ASHPs declines with outdoor temperatures, and thus ASHPs consume more electricity, particularly in colder weather. For this reason, despite recent performance improvements, ASHPs are generally installed with a back-up heating system that can substitute or supplement the ASHP

26 Meister Report, Figure 1, Table 5, Table 7.

during very low outdoor temperatures.[27] GSHPs, on the other hand, use groundwater or the ground itself, which maintains a stable year-round temperature of about 50 degrees Fahrenheit a few feet below the surface. To access this reservoir of heat, GSHPs require a "ground loop," piping that circulates a refrigerant that absorbs heat from the ground or water, or injects heat in cooling mode. A ground loop can be installed horizontally as a "slinky" coil of flexible pipe buried a few feet underground, or vertically by drilling one or more boreholes several hundred feet deep. The ground loop typically makes GSHPs more costly to install, but since the ground temperature is constant throughout the year, they can operate at very high efficiency regardless of outdoor temperature.

An advantage of heat pumps over burning decarbonized fuels (e.g., renewable oil or gas) is that they provide cooling as well as heating, whereas furnaces and boilers burning fuels can only provide heat.[28] In a warming Rhode Island, air conditioning is likely to become more important and by being able to provide both heating and air conditioning, heat pumps can replace not just a furnace or boiler, but also the need for a separate air conditioning system.

A potential disadvantage of heat pumps is the demand they put on the electric system, particularly in a scenario of wide scale deployment. Heat pumps have the potential to create a strong winter peak in electricity demand in the coldest weather. This peak impact is particularly acute for ASHPs, as discussed below in Section III.C. While the analysis below finds that decarbonizing the grid and scaling it up to meet such higher peak demand would only lead to moderately higher electricity costs in the long run, projecting the impact of this dual challenge (decarbonization and scaling up) on prices remains a source of significant uncertainty. It also increases the challenge of building out a regional carbon-free electricity supply in time to meet potentially much higher peak demand.

There is also a question about whether ASHPs should be sized to cover all reasonably expected outdoor temperatures. While ASHPs can be sized to meet all reasonably expected heating needs, this analysis assumes that it is likely more cost-effective to use inexpensive electric resistance heating capacity to cover the small number of hours when temperatures are so cold that ASHPs are not much more efficient than traditional resistance heat.

Another practical disadvantage of heat pumps relative to decarbonized fuels is that converting to heat pumps would require that most of the existing buildings throughout the state would need to have their heating systems replaced, abandoning, altering or removing parts of the existing systems. This would require

27 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. 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). Electric resistance heating likely provides the most cost-effective back-up heating in the long run, since at temperatures below -5˚F the efficiency of an ASHP drops to the efficiency of electric resistance heat. Wood stoves are another potential carbon-neutral back-up heating source. This analysis has not attempted to project the interim use of non-electric backup heat, instead focusing on all-electric Bookend Scenarios to understand the potential magnitude of the electric system impact. However, the analysis below does consider a Mixed Scenario where decarbonized heat is provided from a variety of sources; this scenario offers a good proxy for the interim use of non-electric backup heat sources.

28 A heat pump can also be designed to run on natural gas, and could provide cooling as well as heating, though gas-fired heat pumps are not currently commercially available. Although it would be less efficient than an electric heat pump, a gas-fired heat pump would provide a significant efficiency improvement over gas-fired furnaces or boilers. The COP of a gas-fired heat pump in heating mode is about 1.3 (and 0.6 in cooling mode), relative to efficiencies in the range of 0.80-0.9 for a gas-fired furnace or boiler. (See Baig and Fung, Impact of Carbon Pricing on Energy Cost Savings Resulting from Installation of Gas-Fired Absorption Heat Pump at A Library Building in Ontario, MDPI Proceedings, August 16, 2019). There is currently little information about the likely installed cost of such heat pumps, and so they were not analyzed as a separate option for fully decarbonized heating in this analysis. However, future developments could potentially make them an attractive option. They would likely have relatively high initial costs, potentially similar to electric heat pumps, and would likely require similar modifications to existing buildings, but their fuel costs would be lower than for furnaces or boilers fired by renewable gas.

disruptive construction activity in the homes of most Rhode Islanders, and an initial cost that is much more costly than simply replacing an existing boiler or furnace with a new, more efficient one that is otherwise similar.

3. Decarbonizing Fuels

Rather than installing electric heat pumps to replace the boilers and furnaces that burn fossil fuels, it is also possible to keep the same or similar heating equipment, but to decarbonize the fuels themselves. That is, the fossil natural gas, oil and propane fuels currently in use can be replaced with carbon-neutral "drop-in" substitute fuels, i.e., fuels whose carbon emissions during combustion are essentially releasing carbon that was recently absorbed from the atmosphere to synthesize the fuel. Two examples explained in more detail below are biomass-based fuels, where carbon absorbed through photosynthesis by plants is converted into biofuel and re-released into the atmosphere when burnt, and "Power2Fuels" approaches, which use renewable energy to convert water into hydrogen and add carbon dioxide captured from the atmosphere to make renewable gas, oil, or other fuels. Deploying such drop-in substitute fuels has the advantage that little or no change is necessary inside the building, since for the most part, existing heating equipment and distribution systems can continue to be utilized.

Heating Oil ⇢ Renewable Oil

Currently, about a third of Rhode Island customers use heating oil and another 2% heat with propane.[29] Many of these customers reside outside of Rhode Island's urban core communities. A decarbonized liquid fuel such as biodiesel can be used as a drop-in replacement for heating oil. There are several potential sources for decarbonized heating oil, including those derived from waste oils (used cooking oil), various oil crops (rapeseed, soy, palm) and potentially synthetic liquid fuels produced from water electrolysis and subsequent steps to synthesize carbon-neutral fuels.

In fact, Rhode Island's Biodiesel Heating Oil Act of 2013 currently requires a 5% biodiesel blend (B5) in heating oil.[30] In theory, this blend requirement could be ratcheted up significantly over time. In line with this possibility, the Northeast's heating oil industry has recently committed to achieving net-zero CO_2 emissions by 2050, with interim targets of a 20% biodiesel blend (15% reduction in carbon intensity) by 2023, and a 50% blend (40% carbon reduction) by 2040.[31] At higher blending levels, there may be some "blend-wall" issues for biodiesel.[32] However, there do appear to be solutions to overcome some of these issues[33] and the opportunity exists for Rhode Island to begin increasing its blending requirements along the lines committed to by the delivered fuel industry.

While there are likely some limits on the quantities available from the relatively less costly sources,[34] a synthetic version of biodiesel could be produced in unlimited quantities, at least in theory. The "Power2Liquids" (P2L) pathway, illustrated in **Figure 11**, could use carbon-free electricity, water electrolysis and further refining to provide decarbonized liquid fuel in quantities constrained only by the availability

29 See Meister Report, p.24.

30 State of Rhode Island, Biodiesel Heating Oil Act of 2013, § 23-23.7-4.

31 See https://nefi.com/news-publications/recent-news/heating-oil-industry-commits-net-zero-emissions-2050/ and nbb.org.

32 Today, biodiesel content over 20% may cause several issues with existing equipment – for example, a biodiesel tank must be in a conditioned space since B100 congeals at temperatures below 42˚F.

33 Ibid.; also see a series of modest steps proposed for a conversion to B100 (https://www.netzeromontpelier.org/blog/2018/10/8/biodiesel-for-home-heating, accessed February 2, 2020). See also https://www.hpac.com/heating/article/20925981/b100-makes-the-grade (accessed February 2, 2020), which discusses a Brookhaven National Laboratory test of a hydronic condensing boiler using B100.

34 See RIEC4, Rhode Island Greenhouse Gas Reduction Plan, December 2016 , p.73

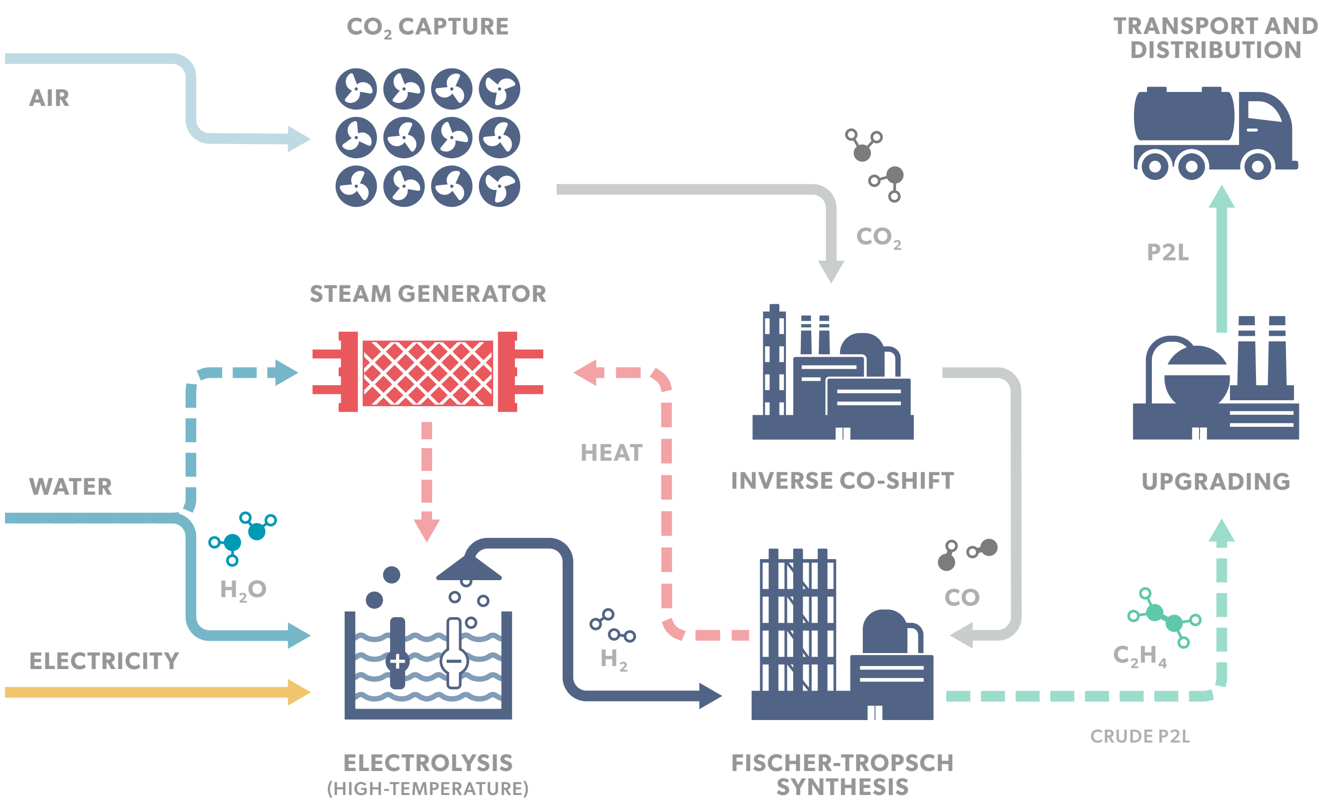


FIGURE 11: POWER2LIQUIDS (P2L) PROCESS

Source: Reproduced from Figure 3, Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel, Umweltbundesamt, September 2016

of renewable electricity and the ability to develop the infrastructure and equipment to produce it. The primary concern with the P2L approach may be the cost of producing fuel in this way. This suggests that even if the supply of relatively low-cost biodiesel from waste products may be limited, the potential for P2L means there is likely no hard limit to the availability of renewable oil.

The remainder of this report will use the term "Renewable Oil" to refer to both biodiesel and synthetic P2L fuels, since the latter is not biologically based.

Finally, while the EPA considers biodiesel to be carbon neutral,[35] some other assessments of the lifecycle emissions of biodiesel conclude that biodiesel production does emit some GHGs. Some estimates suggest that switching to biodiesel could lower GHG emissions by as much as 80%, but not 100%.[36] Similarly, a case study of Fulcrum Sierra BioFuels for the California Low Carbon Fuel Standard estimated a potential GHG reduction of 62.1% with biodiesel.[37] Hence, the decarbonizing potential of B100 for the RI heating sector would likely depend on the assessed lifecycle emissions of B100, which in turn depends on how (and from what) the B100 is produced.

Propane is also used as a delivered fuel for heat

35 See https://www.eia.gov/energyexplained/biofuels/biodiesel-and-the-environment.php

36 See $(S\&T)^2$ Consultants, BIODIESEL GHG EMISSIONS, PAST, PRESENT, AND FUTURE, A report to IEA Bioenergy Task 39, January 2011, Table ES-2

37 See Life Cycle Associates, Life Cycle GHG Emissions for Fulcrum Sierra Biofuels LLC's MSW-to-Fischer Tropsch Fuel Production Process, LCA.6060.120.2015, December 2015, Table 6, page 12.

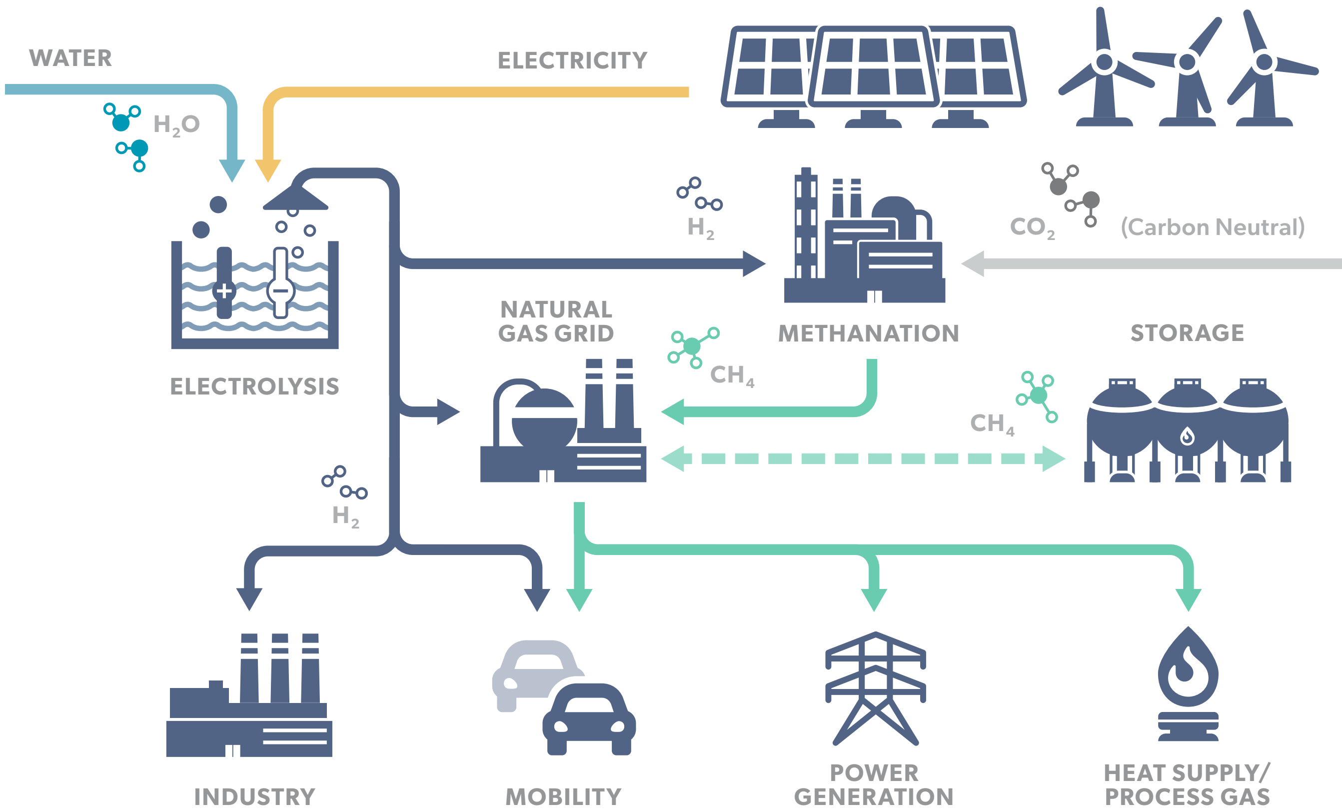


FIGURE 12: POWER2GAS (P2G) PROCESS

Source: Muhammad Akif, Analysis of Gas Power Systems, Today & Tomorrow, 2015, Figure 17, p.21

in Rhode Island, though rarely.[38] Conceptually, renewable propane could be produced by similar processes as renewable gas and renewable oil, including P2Fuel pathways, and so the same types of issues discussed for those fuels are likely to apply to renewable propane.

Fossil Natural Gas ⇢ Renewable Gas

Natural gas (methane) is the dominant heating fuel in Rhode Island, serving 54% of the state's residential customers.[39] Almost all natural gas used today is produced from fossil sources and transported via pipelines to the point of use. Small amounts of methane are available from landfill gas and anaerobic digesters (using animal waste, food and agricultural waste, waste water, etc.), and can be blended into pipeline gas. Two potential gaseous replacement fuels for natural gas are being widely discussed: hydrogen and bio-methane, and a growing number of reports discuss the potential role of decarbonized gas in a decarbonized energy system.[40] In addition, methane can be synthesized via "Power2Gas" (P2G) pathways, which begin by producing hydrogen. As with oil, this report will use the term "Renewable Gas" to refer to both bio-gas and synthetic P2G fuels, and will use "Renewable Fuels" to refer to renewable gas and renewable oil collectively. Figure 12 illustrates the P2G pathway.

Hydrogen can be blended with methane in the gas system, or can be used in pure form as a fuel itself. Most hydrogen is currently produced by splitting

38 See Meister Report, p. 24.

39 Ibid.

40 See for example Black & Veatch, The Role of Natural Gas in the Transition to a Lower-Carbon Economy, May 2019; Navigant, Gas for Climate, March 2019

natural gas into hydrogen and CO_2 via a process called steam methane reforming ("SMR"), which releases the CO_2 into the atmosphere. If the CO_2 were to be captured and permanently sequestered, the hydrogen would be carbon-neutral; this is referred to as "blue hydrogen."[41] Alternatively, "green hydrogen" can be produced from carbon-free electricity by using electrolysis to split water into hydrogen and oxygen. Either of these forms of carbon-neutral hydrogen can be used to replace natural gas as a heating fuel, and potentially in industrial high-temperature process heat applications. However, hydrogen is not a true "drop-in" fuel since it differs from methane in ways that may require significant upgrades and investments to the existing gas infrastructure. This would likely involve equipment both in front of the meter (transportation and distribution pipes, and associated infrastructure) and behind it (internal gas lines, gas appliances).[42] Thus hydrogen sacrifices the ability to continue using existing infrastructure, as well as the accompanying convenience and cost advantages. For these reasons, we do not focus on hydrogen as a primary candidate for a gaseous heating fuel, but believe that renewable methane is likely to be more suitable.[43] Nonetheless, if hydrogen does overcome these disadvantages to be the more attractive version of renewable gas, or if hydrogen and renewable methane are both viable, the conclusions we reach below about renewable methane are also applicable to renewable hydrogen.

The alternative to hydrogen is to create renewable gas that is the chemical equivalent of natural gas. Methane can be produced from various biological sources – landfill gas, anaerobic digestion or the gasification of biological feedstocks such as wood, food waste, municipal solid waste, etc.[44] Renewable gas can also be produced synthetically via a P2G pathway by combining hydrogen from water electrolysis with CO_2 from a carbon-neutral source, in a chemical process is called "methanation." Renewable gas has the advantage of being fully compatible with existing natural gas heating equipment, and with a very large existing gas infrastructure, including pipelines, gas distribution systems and large gas storage fields, where it can be stored for long periods of time (particularly useful for dealing with seasonal storage needs).

One concern with renewable gas is its potential cost, which may be considerably higher than current fossil natural gas prices, particularly for P2G pathways. Another factor is that gas pipeline and local distribution systems leak some of the gas that is transported. Methane is a particularly strong GHG itself, 30 to about

41 Since natural gas is currently very inexpensive in the U.S., hydrogen produced in this way could be relatively low cost if the cost of carbon sequestration were reasonably low, though sequestration has so far remained disappointingly costly.

42 It may be possible to blend hydrogen with natural gas at low concentrations (up to about 10%) without significant infrastructure upgrades. This can achieve near-term GHG reductions, but since such blending is limited to low concentrations, it does not offer a pathway to full decarbonization. The hydrogen "blend wall" beyond which significant infrastructure upgrades may be required depends on the composition of the particular gas distribution system in question, and determining it would require detailed study. For a more detailed assessment of various issues related to hydrogen blending, see for example Melaina et al., Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, NREL, March 2013.

43 Hydrogen may offer advantages in some particular applications, particularly for high-volume uses where dedicated infrastructure might be used, avoiding the need for broader upgrades. This could include large industrial applications, and also power generation, where hydrogen could offer an attractive way to store energy for use in thermal generators, to facilitate matching intermittent generation to load and providing ancillary services. The opportunities for hydrogen to address some of these industrial and power generation needs warrants further study. For one discussion of some of the opportunities for hydrogen, see "Hydrogen in a low-carbon economy," UK Committee on Climate Change, November 2018, at https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf.

44 For an in-depth discussion of both biological feed stocks, see American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reductions Assessment, December 2019

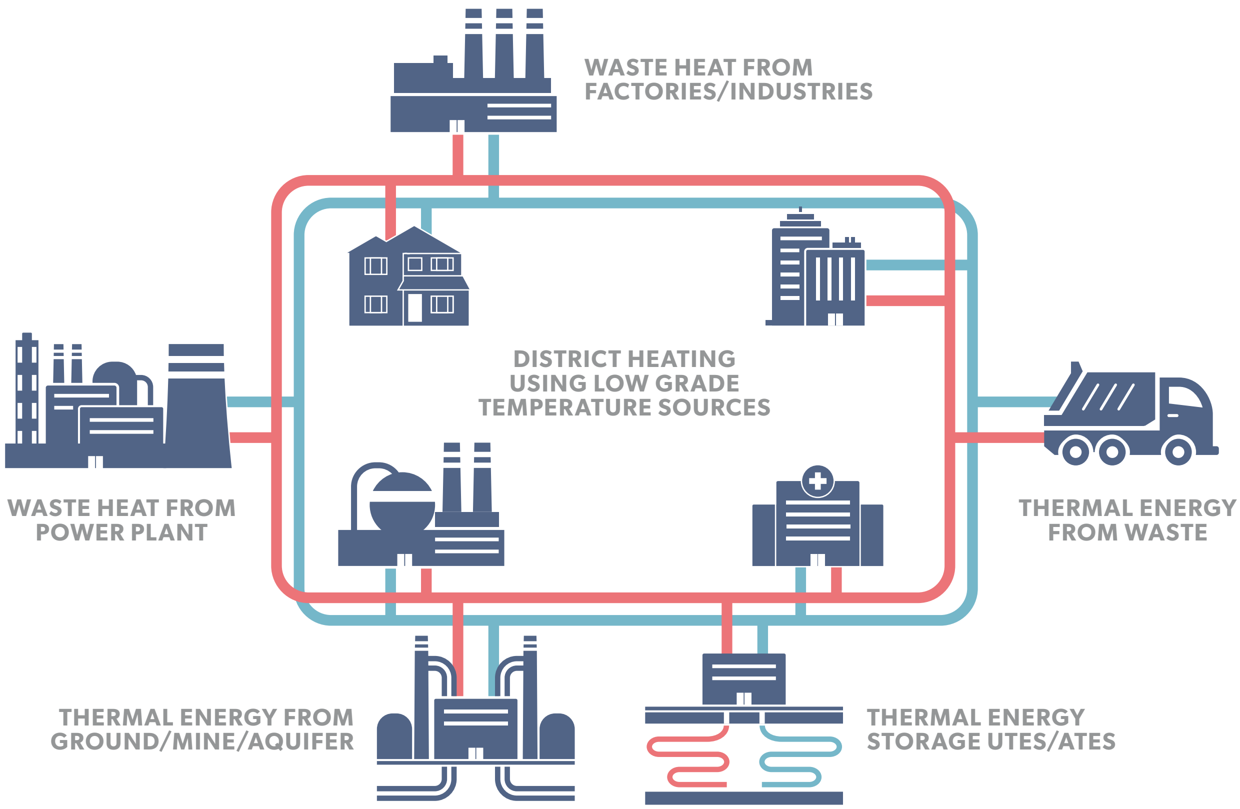


FIGURE 13: ILLUSTRATIVE SCHEMATIC OF DISTRICT HEATING SYSTEMS

Source: https://www.flexis.wales/research-item/wp9-smart-thermal-energy-grid-prof-hr-thomas/low-grade-district-heating-network/

85 times stronger than CO_2,[45] so even if the renewable gas itself is entirely decarbonized, any leaks would partially offset the emissions reductions of replacing fossil natural gas with renewable gas. At the current leak rate, methane leaks can add roughly 30%-85% to the GHG of the CO_2 in the combustion products. While there are ongoing efforts to reduce leaks, it is unlikely that they can be eliminated entirely. Finally, renewable gas, like natural gas, presents safety risks from indoor gas leaks, and health risks related to indoor air quality).

4. Decarbonized District Heating

All of the decarbonization solutions discussed so far concern the "fuel" or "technology" used to decarbonize heating. Any of these approaches can be applied in a distributed system, with every individual building unit having its own fuel conversion system such as a boiler, a furnace or a heat pump. However, heating can also be provided through more centralized systems where, rather than distributing fuel (oil, gas, electricity) to individual buildings, the heat itself is produced centrally and distributed to individual buildings for use. The latter is often referred to as "district heating", which is prominent in several northern European and Asian countries and, on a smaller scale, on university and office campuses, etc. Figure 13 illustrates how a district heating system works.

45 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. The 100-year global warming potential for methane is 30, and the 20-year GWP is 85, based on U.S. EPA ranges (U.S. EPA, "Understanding Global Warming Potentials", available at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials). This is consistent with IPCC estimates (IPCC, Fifth Assessment Report, Chapter 8: Anthropogenic and Natural Radiative Forcing, p.714, Table 8.7).

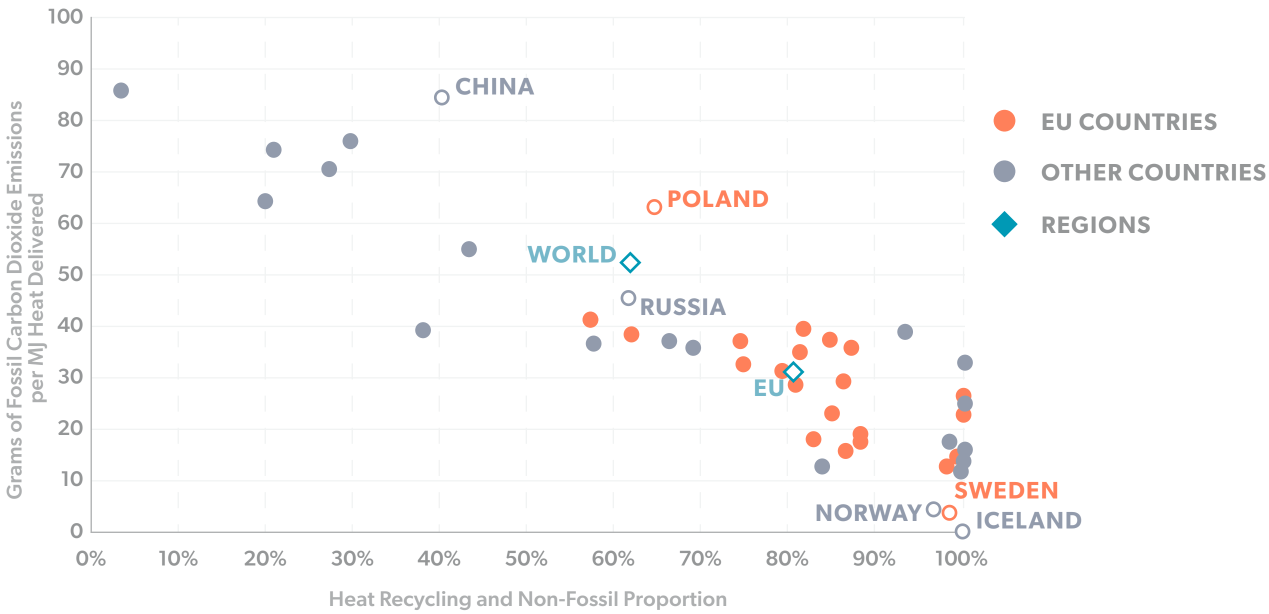


FIGURE 14: CARBON INTENSITY OF SELECT DISTRICT HEATING SYSTEMS

Source: Sven Werner, International review of district heating and cooling, Energy 137 (2017), pp. 617-631

Using district heating as a substitute for the typical distributed heating system provides additional opportunities to decarbonize heating by potentially improving the economics, feasibility or speed of transforming the heating sector.

District heating systems have been around since the 19th century and were initially introduced for a variety of reasons, including to reduce local air pollution (by centrally creating heat through the combustion of coal, oil or gas) and to take advantage of waste energy and heat (by using combined heat and power plants, waste incineration or by directly using waste heat from industrial processes). As a primary source of space and water heating, district heating systems are particularly prominent in the former Soviet Union, China and several northern European countries (Denmark, Sweden, Finland, Germany). In particular, as shown in **Figure 14**, Scandinavian countries have achieved district heating systems with very low carbon emissions.

In most district heating systems, heat is generated centrally – for example in a large combined heat and power plant (a power plant, where the heat that is generated as a byproduct is used rather than wasted) – and then distributed through a network of pipes to end users. The transfer medium can be either steam – such as the district heating system still in place in parts of New York City – or via warm water, which is then used to heat buildings. More recently, “mini district heating” has emerged as a possible alternative to large centralized systems. One particular application that has received recent media attention is the development of so-called GeoMicroDistricts[46] that create neighborhood ground source heat loops that can deliver heat to multiple buildings in a particular neighborhood.

Two of the major advantages of district heating are that it takes advantage of large economies of scale by producing heat centrally and thus avoiding the need for furnaces and boilers at the end user site and

46 See http://www.hydrogenfuelnews.com/massachusetts-might-replace-natural-gas-with-geothermal-heating/8538985/

also that they allow effective use of waste heat. As a consequence, district heating systems have been shown to be very cost effective heating options, especially in new developments such as university campuses or new housing developments, i.e., where the district heating system does not replace an already existing system. Similarly, community-systems using a common ground loop have the potential to significantly lower the cost of the ground loop.[47] Larger (community) scale systems likely also create opportunities for operational efficiencies by taking advantage of diversity of heating and cooling demands from the various buildings connected to the system. For example, if such systems are installed in neighborhoods with both commercial and residential (and perhaps even industrial) customers, simultaneous demand for both heating and cooling – for example for refrigeration or warm water production – can result in such a system operating at higher average efficiencies (and potentially lower overall costs by requiring a smaller size when compared to systems serving single buildings.[48]

The most significant technical challenges for district heating systems are their proper sizing – once in the ground, it can be costly to change the overall capacity to deliver heat, for example in response to growing demand via population density in a given area, as well as the fact that the cost effectiveness depends on the level of participation. Put differently, district heating systems can be very cost effective[49] if everybody participates (by spreading the high fixed costs of such a system over many customers), but less so if participation is low. In areas without preexisting district heating systems, this makes adoption of district heating via switching from existing heating potentially challenging.

Finally, decarbonized district heating solutions face some of the same practical barriers as heat pumps. The buildings to be served by a proposed district heating system would need to have their heating systems replaced, abandoning, altering or removing parts of the existing systems, and requiring disruptive activity in those buildings and in the neighborhood. In addition, converting to a district heating solution requires high participation to obtain the potential efficiencies, which requires the agreement of many individual homeowners and building owners in the affected area.[50]

5. Other Considerations

Several other considerations influence the cost and feasibility of heating decarbonization solutions and should be considered when developing a Rhode Island heating sector transformation strategy.

First, the attractiveness of various decarbonization alternatives for space and water heat may be influenced by building size (up to a point), even though the basic solution pathways are similar. While smaller commercial buildings are often similar to larger residential buildings, most large commercial buildings (and often large multifamily residential buildings) differ. They tend to use

47 See Justin Mahlmann and Albert Escobedo, Geothermal Heat Pump Systems for Strategic Planning on the Community Scale, ACEEE Summer Study on Energy Efficiency in Buildings, 2012, which claims that for single family residential applications (typically less than 10 tons of heating capacity) the cost of the ground loop is $50-$100 per foot of ground loop. For systems with 100 tons or more of heating capacity, the costs decline to $15-25 per foot. As one example, a system for Ball State University with over 1,000 tons of heating demand requiring 680 boreholes of 500 feet of depth each (the equivalent of 680 single family systems), the costs decline to $11 per foot. (p.6).

48 Ibid, p.6.

49 A feasibility study commissioned by HEET concludes that GeoMicroDistricts can result in significant installation cost savings relative to individual GSHPs. Buro Happold, GeoMicroDistrict Feasibility Study.

50 While the district heating solution also presents a similar up-front cost barrier to other GSHP solutions, this might be mitigated to the extent the distribution utility is authorized to finance, build and operate the system as a part of its business model, including it in rate base. In Massachusetts, the state regulator is considering some pending utility-sponsored geothermal proposals. See https://www.wbur.org/earthwhile/2020/01/13/heat-eversource-geothermal-energy-climate-change.

boilers for heating and a combination of chillers and cooling towers for cooling. In these larger buildings, heating is relatively less important and cooling more important than in smaller buildings because of the lower surface area to volume ratio, and the often large density of incidental heat sources within the building (lights, computers, people). Internal heat (and cooling) distribution systems are mostly hydronic, in contrast with the large share of air-based (forced hot air, central A/C) systems in typical residential settings. Although this report does not explore this in great detail, the decarbonized solutions described above can work in buildings that have very different heating loads, different uses and different building-level heat distribution systems, though the particular details of how they are applied will differ from building to building.

Second, different buildings are likely to require different solutions in part because of the considerable diversity of existing buildings. The idiosyncratic features of a given building or site can affect which decarbonization solutions may be feasible or reasonable. Such features can include whether and how well they are insulated, and the ability to add insulation, interior ductwork or hydronic distribution; whether a given building has access to the gas distribution network; or whether the geology is appropriate for a ground loop for a GSHP – indeed even whether there is enough space in an urban area to install a ground loop.

Third, while it seems likely that electricity will play an increasing role in any decarbonized future (for transportation as well as heat), the same is less clear for gas and the gas distribution system. If many existing gas customers adopt electric alternatives for part or all of their heat needs, the throughput on existing gas distribution systems will decline, perhaps significantly. Even if the carbon intensity of the gas flowing through these pipes can be reduced – e.g., by blending with increasing shares of renewable gas – the reduced throughput will concentrate the (essentially fixed) costs of the gas distribution system more heavily onto each remaining unit of gas. Increasing distribution rates, particularly if combined with higher costs for the decarbonized gas itself, could cause a substantial increase in delivered gas prices for local utility customers. This raises some important issues. For example, low- and moderate-income customers may have limited ability to switch from gas, due to the high initial cost of electrified heat pumps, and because they are more likely to be renters unable to control the heat source in their homes. Absent some way to counteract this, they could bear the brunt of gas cost increases. More generally, it raises questions about whether and how the gas system may need to be reconfigured. This might include reducing or eliminating service in residential areas where heating electrification is widespread, raising the question of how to "unwind" part of the network in an orderly way, and particularly how to protect vulnerable populations in the process, all while maintaining the economic health of the gas utility, so that it can ensure safe and reliable service to those customers who continue to rely on gas. And it could include maintaining or even expanding the gas system in areas like industrial zones where there are few viable alternatives to burning fuel. The potential future of the gas distribution system has thus become an increasingly important topic for a decarbonized future.[51] In Rhode Island, however, one utility provides both electric and gas distribution services. It may be possible to address or mitigate this effect by regulating the utility as an "energy delivery company," instead of treating the entity as separate gas and electricity businesses for ratemaking purposes.

Finally, the attractiveness of any of the above solutions

51 For example the California Public Utility Commission (CPUC) has initiated a regulatory proceeding that requires advance planning to explore various potential future paths for natural gas infrastructure. (CPUC, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning, Proceeding R2001007, issued January 27, 2020)

may depend on "systemic" effects. As an example, the price of electricity may depend on how widespread ASHPs are adopted. ASHPs increase the "peakiness" of electricity demand, which increases the cost of electricity and in turn impacts the economic attractiveness of ASHPs (as well as affecting the cost of other electricity uses). The best strategy may also depend on a number of practical implementation issues: How much cost-effective weatherization can actually be achieved by 2050? How many homes can realistically be converted to heat pumps by 2050, given the need for specialized labor to perform the installations and the current tightness of this labor force? How do geological and other local conditions affect the feasibility and cost of GSHP? How much renewable oil supply is available, and how does this compare with potential demand, accounting for the fact that Rhode Island may not be the only state relying on renewable fuels as a part of their decarbonization strategy? For these reasons, a wide range of cost and implementation issues must be considered when developing a heating transformation strategy for Rhode Island.

Methodology

This section describes the methodology used to analyze various heating decarbonization pathways for Rhode Island at a summary level. A more detailed description of the methodology, including modeling and assumptions, is included in the **Technical Support Document**.

Research Questions

1. **Understand the relative economic attractiveness of the decarbonized heat solutions identified, as applied to the primary heating applications in Rhode Island.**
2. **Understand how decarbonizing may affect related energy sectors that provide the energy for heating (i.e., renewable fuel and clean electricity), and how these feedback effects impact the costs to consumers, for heating and for overall energy consumption.**
3. **Identify the implications of these analyses that can be used to guide policies for heating sector transformation.**

HEATING NEEDS AND DECARBONIZATION SOLUTIONS

To understand the attractiveness and feasibility of various decarbonization pathways various heating situations were mapped to decarbonization solutions, as illustrated stylistically in **Figure 15**.

Figure 15 does not explicitly represent all building types, current fuels, applications or decarbonization solutions, though it does cover the vast majority of heating situations and decarbonization solutions for Rhode Island. Additional options such as the use of solar hot water heating or the use of wood heating may exist, though they will likely play only a relatively small and complementary role in transforming the Rhode Island heating sector.

Two sets of arrows (in different colors) in **Figure 15** provide two examples of "representative" heating situations, for which decarbonization solutions were identified as "applicable" and therefore analyzed for a specific building type/current fuel/application.

Preliminary analysis showed that a significantly smaller subset of "representative" heating situations can be used to analyze the attractiveness of heating decarbonization solutions across the full span of heating applications. This is because, ultimately, the feasibility and attractiveness of heating decarbonization depends heavily on a small number

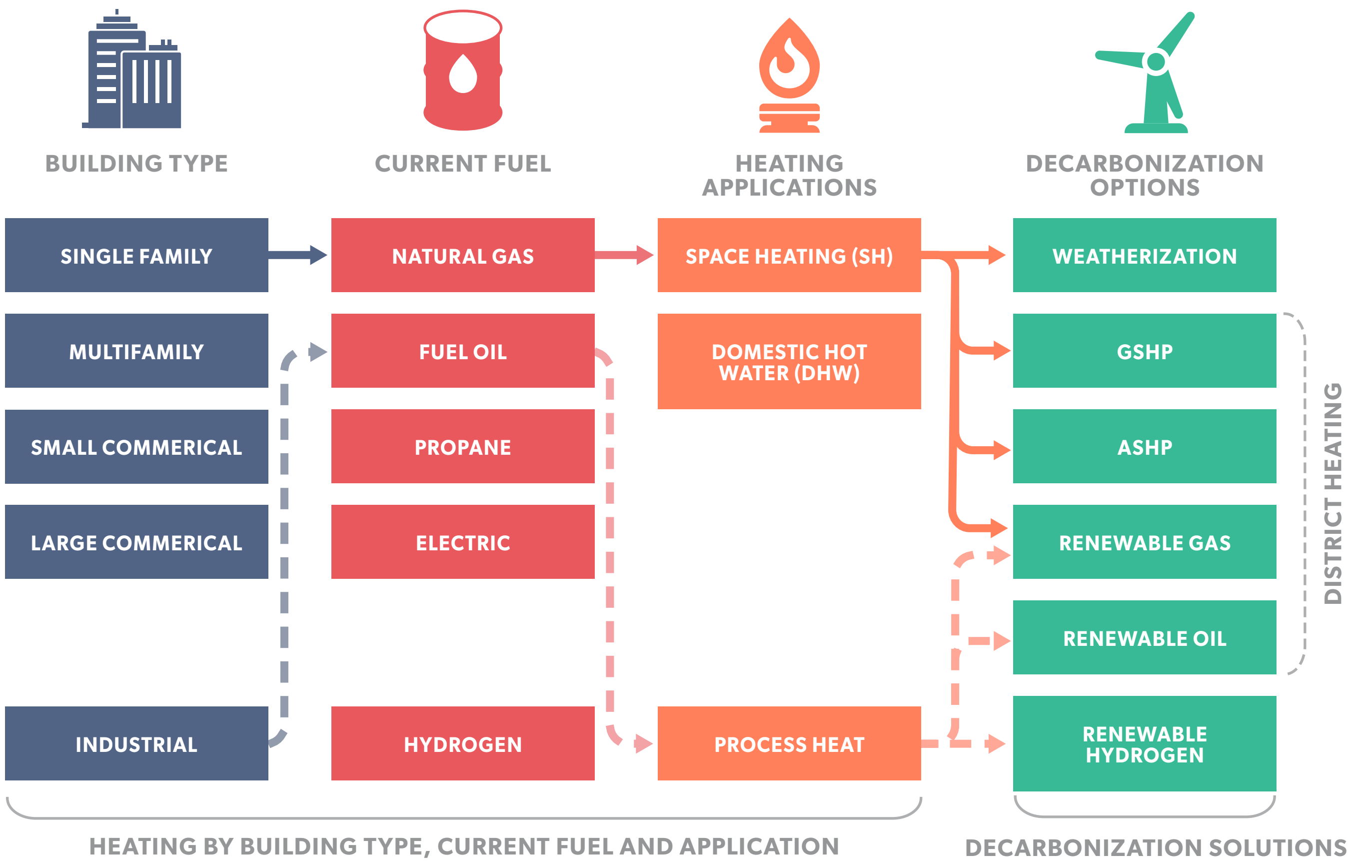


FIGURE 15: STRUCTURE OF HEATING TRANSFORMATION ANALYSIS

Note: Arrows indicate two situations. 1) A single-family home currently using natural gas for space heat could decarbonize using efficiency in combination with a heat pump or renewable gas (solid arrows). 2) An industrial facility currently using oil for process heat could decarbonize by substituting renewable oil, renewable gas, or renewable hydrogen (dashed arrows).

of factors. For space heating, the economics (and in some instances the feasibility) of various decarbonization solutions are primarily driven by the total heating demand for a given building, and the current heating system. Up to a certain size, residential (single- and multi-family) and commercial buildings tend to utilize the same types of fossil heating technologies, and can be transformed using similar decarbonization solutions. Current heating technologies in larger buildings differ from those used for smaller buildings; while this does not fundamentally alter the decarbonization solutions for such buildings, it may affect the cost tradeoffs among the decarbonized solutions. Similar relationships hold true for domestic water heating. Industrial heating represents a small share of the overall Rhode Island heating demand and is highly specific to particular industrial applications, for which little detailed information is available. For this reason, industrial heating applications were treated separately and more qualitatively.

ECONOMIC MODEL OF DECARBONIZED HEAT

To explore the economics of heating decarbonization for "representative" residential/commercial heating situations, this study uses an economic model to estimate annualized heating costs. This model can be applied to both current fossil and future decarbonized alternatives. Annualized costs include both "fuel" costs (natural gas, oil, electricity) and equipment costs (furnace or boiler, heat pump, etc.), amortized over the expected life of each major equipment component. Doing this requires the use of a discount rate to enable comparing the initial up-front cost of equipment installation or replacement with a stream of future costs and benefits. When different heating options involve a very different split between upfront costs and ongoing operating costs, the discount rate can matter: a higher discount rate means that the up-front installation costs are more important relative to the costs and benefits that occur in the future; a lower discount rate means the opposite – that upfront costs matter less. Since the available heating decarbonization solutions do differ substantially in that regard – GSHPs, for example, have significantly higher installation costs than ASHPs, which are in turn more costly than traditional furnaces and boilers – this may be an important issue. The quantitative analysis uses a 3% (real) discount rate, reflecting a commonly used "social discount rate", such as is often used to determine the value of avoided greenhouse gas emissions.[52] However, there is evidence that individuals, when facing decisions about investments like energy efficiency that trade off upfront costs vs energy cost savings over time, choose as if they have a discount rate substantially higher than 3%. To reflect this, we also show "payback periods" for the tradeoffs between alternatives, to illustrate how various decarbonization solutions might be viewed by consumers and how adoption rates might be influenced by a longer or shorter payback period.

Given that the two primary pathways are the decarbonized electrification of heating and the decarbonization of "fuels," it is necessary to consider the impacts of electrifying heating on the electricity sector, which in turn impacts the cost of electricity, and the potential cost of renewable fuels.[53] Both will be major factors in the attractiveness of the respective pathways, particularly since widespread adoption of some of these technologies could impact the pricing of the respective fuel. To explore the issue of feedback between decarbonizing heat and the availability and costs of electricity and/or decarbonized fuels, several "Bookend Scenarios", in which each technology option is evaluated in a context where essentially all the heat in the region being provided by that technology are developed.[54] These investigations generate several important insights in their own right, which are discussed below in Sections III.C and III.D. **Figure 16** illustrates the analytical modeling structure used to develop quantitative comparisons between various heating decarbonization solutions, incorporating interactions with the electricity sector, and considering the availability and cost of renewable fuels. The primary focus of these analyses is space heating, which represents about 60% of total residential energy demand in Rhode Island; we also examined options to decarbonize domestic water heating (the second largest energy need, at 16%). In addition to these quantitative analyses, we performed a more qualitative analysis of considerations related to decarbonizing industrial heating.

Because projecting the costs of heating three decades into the future necessarily involves significant uncertainties, the model considers a range of potential future costs. There are also a number of non-quantifiable factors related to

52 There is no "correct" discount rate per se. There is a large literature discussing the use of a "social discount rate" to evaluate policy that takes into account various societal issues rather than just reflecting private decision making. In general, social discount rates are in the range of 2.5-7%, and some argue for a 0% discount rate (in real terms). For example, U.S. estimates of the social cost of carbon use discount rates of 2.5%, 3% and 5% (See Resources for the Future, Social Cost of Carbon 101, August 1, 2019). See also OMB Circular A-4, September 17, 2003, which includes an in-depth discussion of the rationale for using various discount rates.

53 We do not separately model the cost and availability of renewable oil, but instead rely on existing modeled prices of renewable oil.

54 The Bookend Scenarios are: all GSHP, all ASHP, and all Renewable Fuel (where customers retain the fuel type they currently use, but the fuel itself is replaced with a renewable version – fossil heating oil is replaced with Renewable Oil (B100) and fossil natural gas is replaced with Renewable Gas).

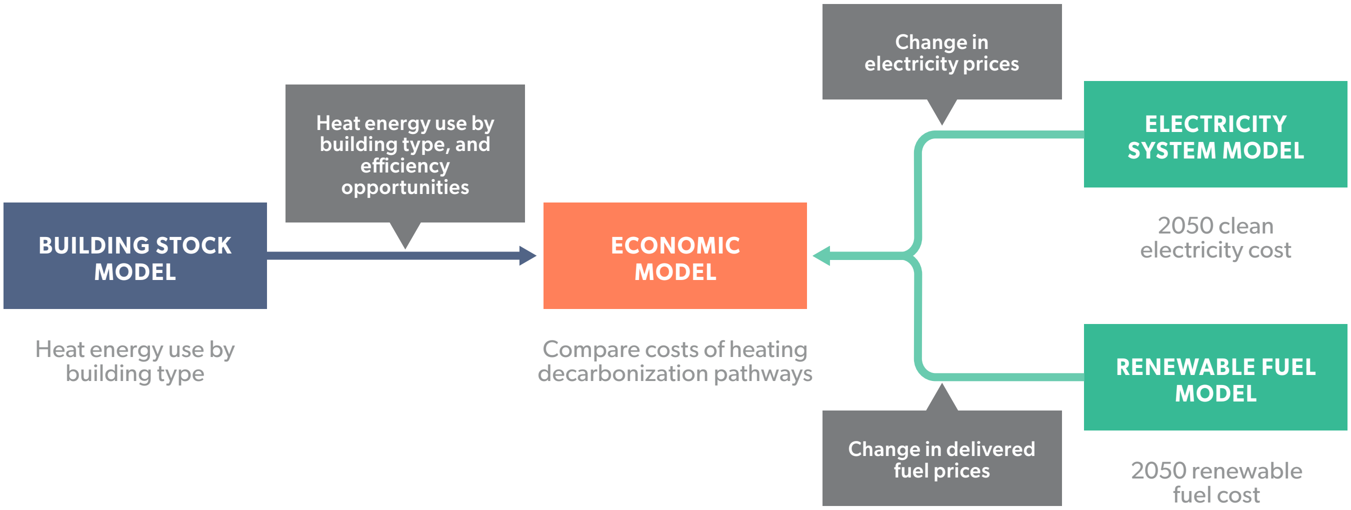


FIGURE 16: ANALYTICAL MODEL OVERVIEW

the heating decarbonization solutions, such as implementation barriers and other not easily quantified benefits and costs. These more qualitative factors are also considered as part of the overall assessment of the attractiveness of a given solution for a given building type. Before describing the financial model itself, the electricity and renewable fuels models are described next.

ELECTRICITY SYSTEM MODEL AND IMPACTS OF DECARBONIZED HEAT

Because heating in northern climates requires a large amount of energy, widespread decarbonized electrification of heating via heat pumps would have a substantial impact on the demand for electricity. The impact on the shape of electricity demand may even be greater, since heat needs are highly correlated across the region, peaking in the coldest weather. These impacts are evaluated using the Bookend Scenarios introduced above, in the context of a decarbonized electricity sector. Electrifying all heating in New England with either GSHP or ASHP would turn the current summer-peaking New England electric system into a strongly winter-peaking system, affecting supply needs and electricity prices. Although electric heating and cooling use essentially the same technology, the electricity needed to heat a building with a heat pump is much greater than the power required to cool it with an air conditioner, because the temperature differentials that must be maintained between outside and inside are much larger in winter (50-70˚F) than they are in summer (20-30˚F).

However, there is a distinct difference between air source and ground source heat pumps. Either technology must accommodate the fact that the demand for heat is much greater when outside temperature falls very low. But it is easier for a GSHP to provide the necessary amount of heat than it is for an ASHP. GSHPs draw heat from the ground, which is always about 50˚F, whereas the ASHPs draw heat from the outside air, which contains less heat energy at just those times when the demand for heat is greatest. This means that when it is very cold, ASHPs must use considerably more electricity to deliver the same amount of heat as GSHPs. That is, at very low temperatures, its efficiency is much lower.

The efficiency of a heat pump is measured by its "coefficient of performance" or CoP – the ratio of output heat energy to the amount of electric energy consumed. For a GSHP, this CoP is constant at about 3.6 regardless of outside temperature – i.e., for each kWh of electricity consumed, the GSHP delivers about 3.6 kWh of heat. But for ASHP, the CoP depends on the outside air temperature. At an outside temperature of 50˚F, an ASHP has a CoP very similar to a GSHP. But the CoP for an ASHP falls to about 1.0 when air temperature is around 0˚F. This means that when it is 0˚F outside, an ASHP will require about 3.6 times as much electricity as a GSHP to deliver the same amount of heat. Thus in the ASHP Bookend Scenario, the peak electricity demand from heating would be about 3.6 times what it is in the GSHP scenario. (Of course the overall system peak differs by less than 3.6x because of the other electric load that is similar in either case).

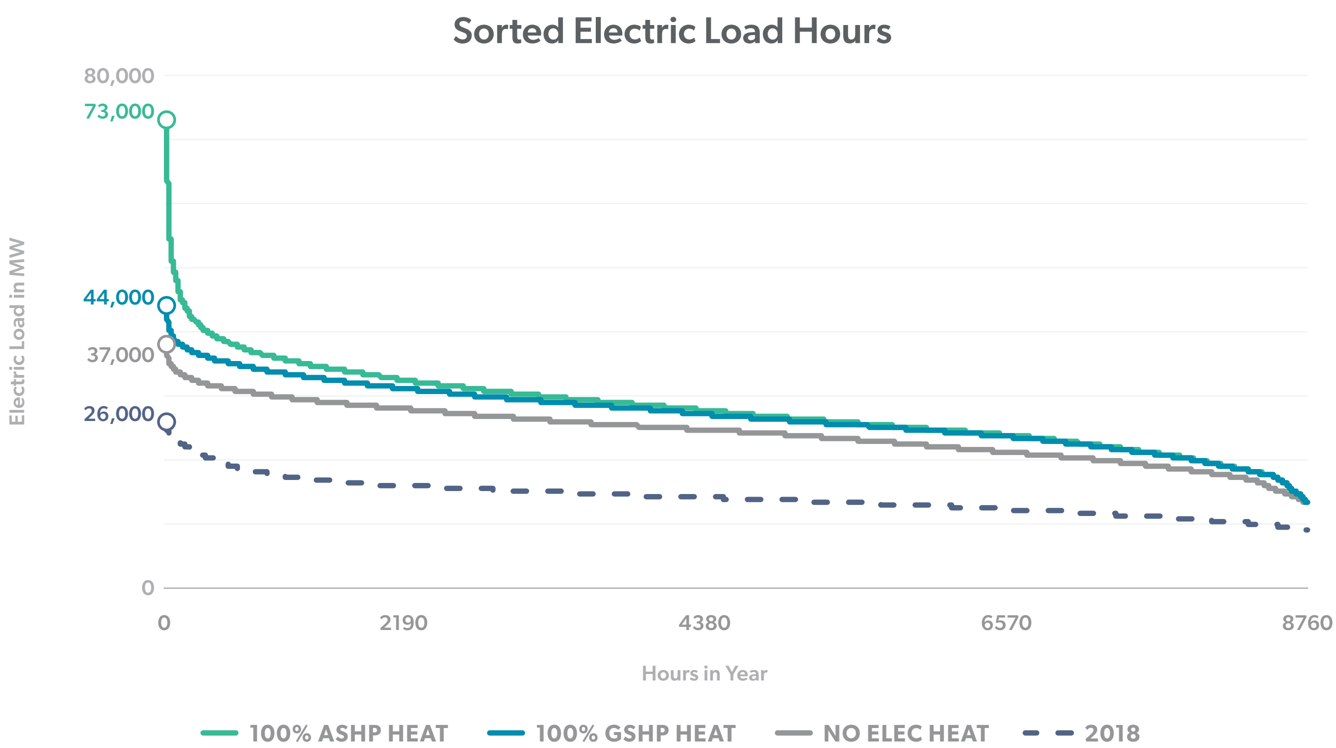
Figure 17 illustrates the projected impact of electrifying all New England heating via all ASHPs vs all GSHPs in 2050, when it is also assumed that transportation will be mostly electrified. As can be seen, the impact of electrifying heating on total energy consumption is modest: Demand increases 12%-15% relative to demand without heating electrification (but with transport electrification). With all GSHPs, peak demand increases by 17%, slightly more than the energy increase. But with all ASHPs, the increase in peak demand would be dramatic at 94%, almost twice the peak demand without electrified heating via ASHPs. As can be seen in the bottom panel of the figure, which ranks hourly demand from highest to lowest, this increase in peak is caused by a very small number of hours, precisely those when outside temperatures decline to levels, where the efficiency of ASHPs approaches 100% (and hence is equal to the efficiency of electric resistance heat; in fact, we assume that electric resistance will be used to supplement ASHPs to meet peak). The almost doubling of peak demand with an all ASHP system could result in materially higher electricity prices.[55] Because ASHPs require more electricity, and their disproportionate peak impact would increase electricity prices, widespread ASHP adoption could substantially raise the cost of electric heating.

Figure 18 displays estimates of the delivered electricity price in these future scenarios based on the projected cost of building a renewable power system that would serve each of these load profiles.[56] The current average delivered price for power in Rhode Island is 18¢/kWh. In a decarbonized 2050 system without electrified heat, electricity costs would be somewhat higher than today, at 22¢/kWh (in $2018). With all heating electrified via GSHP, the electricity price would essentially remain unchanged (21.8¢/kWh), but with ASHP, it would be considerably higher, at 24.6¢/kWh. This accounts for the higher cost of generation, since more peaking capacity would be necessary (in a decarbonized system, this would be a combination of storage such as batteries, and possibly conventional generators using renewable fuel). It also considers the additional costs for the transmission and distribution system, which must be sized to meet the system peak and is thus heavily affected by a higher system peak.

The estimated increase in retail costs for a fully decarbonized power supply able to meet electricity demand in each of the scenarios is relatively moderate, in the range of 10-35%. These estimates are of course uncertain, since the costs of many of the resources to supply 100% clean electricity are evolving rapidly, and the generation component of clean energy is projected to increase more sharply. But some of this increase will likely be offset by lower per-kWh transmission and distribution costs. Even though a considerable amount of new transmission

55 The modeling of electricity prices assumes some mitigating factors such as the use of batteries to shift demand away from the highest demand hours. Other mitigating options not modeled include the use of thermal storage, which is just emerging as a potential technology option for ASHPs. For more detail on electric sector modeling underlying these calculations, see the Technical Support Document.

56 A higher peak demand would affect the cost of both the generation of renewable electricity and the cost of the transmission and distribution system needed to reliably deliver electricity to consumers.



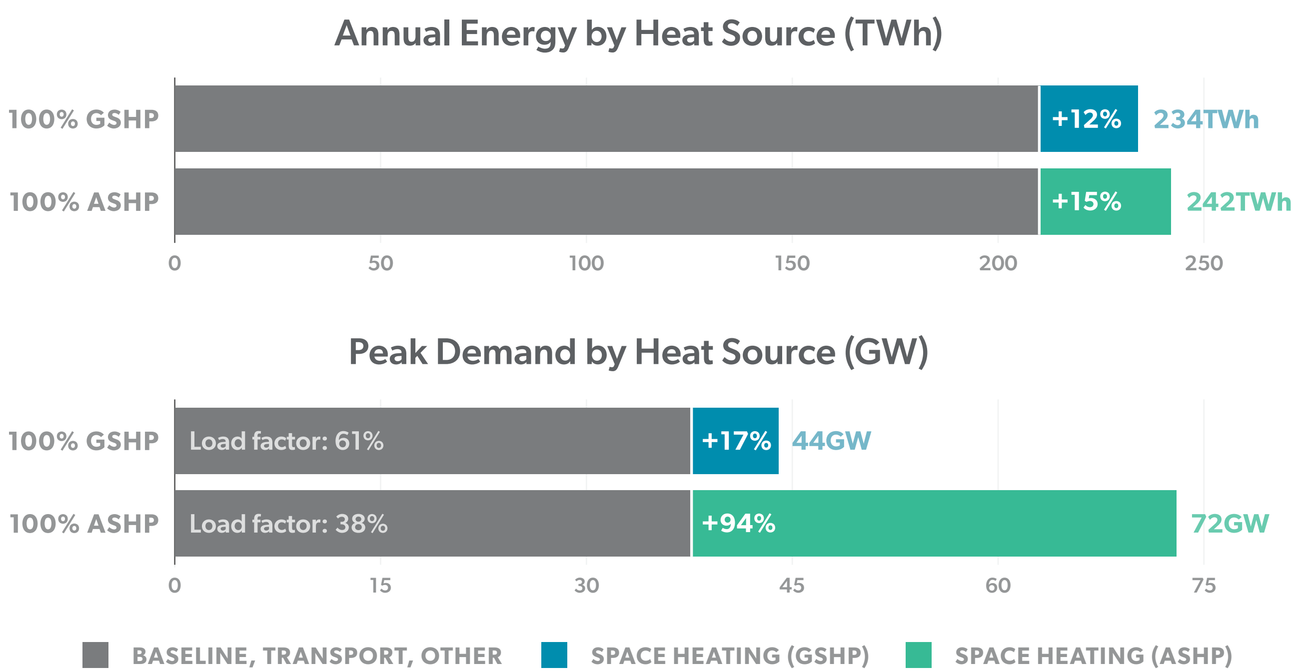


FIGURE 17: IMPACT OF ELECTRIFYING HEAT VIA ASHP VS GSHP – 2050

Note: The 2050 load characterization assumes that the transportation sector is mostly electrified, and also assumes continuing efficiency improvements in baseline uses of electricity (current uses).

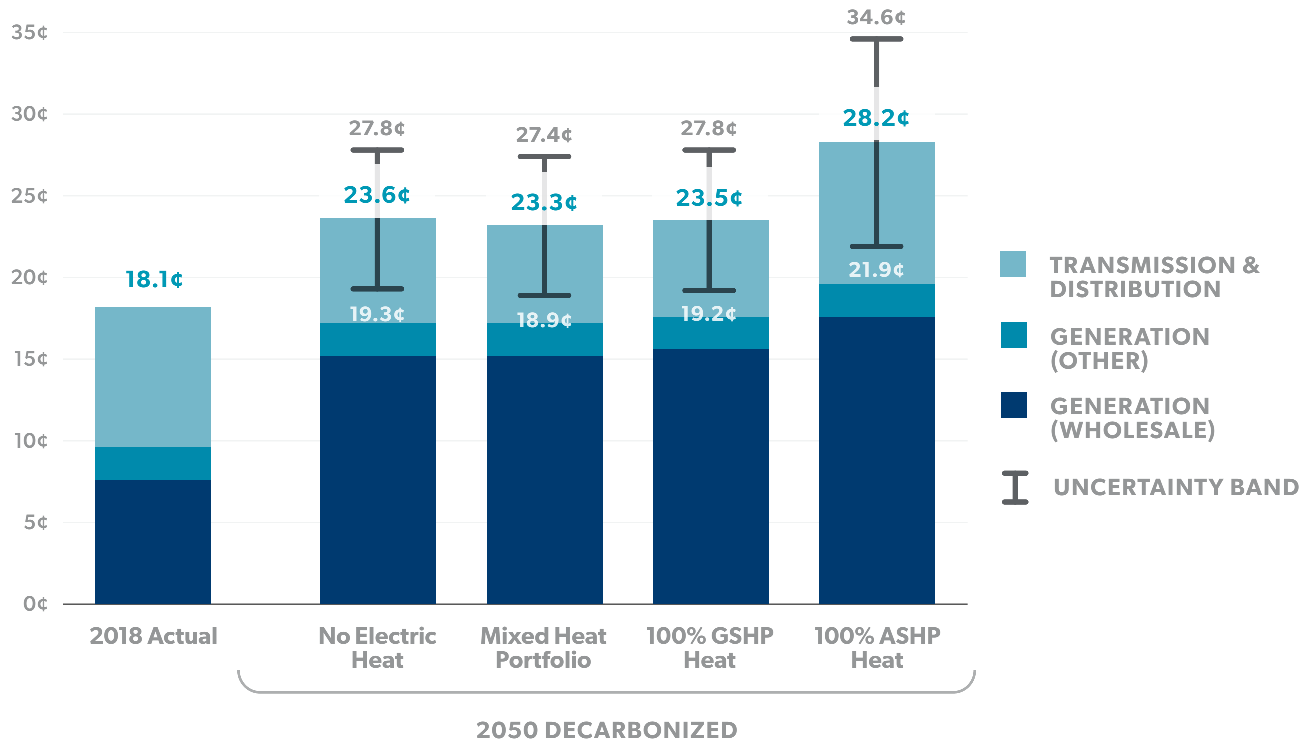


FIGURE 18: RHODE ISLAND ELECTRICITY PRICE BY SCENARIO (cents/kWh, IN 2018$)

Note: The 2050 Decarbonized estimates assume that transportation is largely electrified. Generation (Wholesale) represents the cost of an emissions-free electricity generation system, based on the electric sector model described in Technical Support Document. Generation (Other) reflects costs related to electricity supply beyond the supply resources themselves (administrative costs of the ISO and utility to manage electricity purchasing, etc.). The high and low electricity price estimates reflect a +20% (high) to -20% (low) change in the generation component. T&D costs reflect the cost 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 mid-point of the two ($187/kW-year) for the nominal estimate.

and distribution infrastructure will be needed in a decarbonized and largely electrified future, and total T&D costs will be higher (especially in the 100% ASHP Heat Scenario), the total volumes of power delivered, including for EV charging as well as electrified heat, are likely to increase by even more, lowering the unit T&D cost. Much of this effect is due to EV charging, which provides significant year-round demand with a somewhat complementary daily load shape relative to other electricity demands, thus increasing the utilization of the existing T&D infrastructure. In addition, the T&D system can accommodate 20-25% more power in winter than in summer, meaning that the winter peak caused by electrified heat will require substantially less T&D expansion than would a summer peak.

RENEWABLE FUELS MODEL

The second basic pathway for decarbonizing heating is to substitute renewable fuels, such as renewable oil or renewable gas, for the current fossil oil and natural gas used in the vast majority of cases. A major advantage of this pathway is that renewable fuels generally require little or no changes to existing infrastructure and equipment, either at the customer site or in the delivery system.[57] As discussed above, there are a number of

57 As discussed above, renewable hydrogen, if used beyond low concentrations, would likely require upgrades to many components of the gas infrastructure.

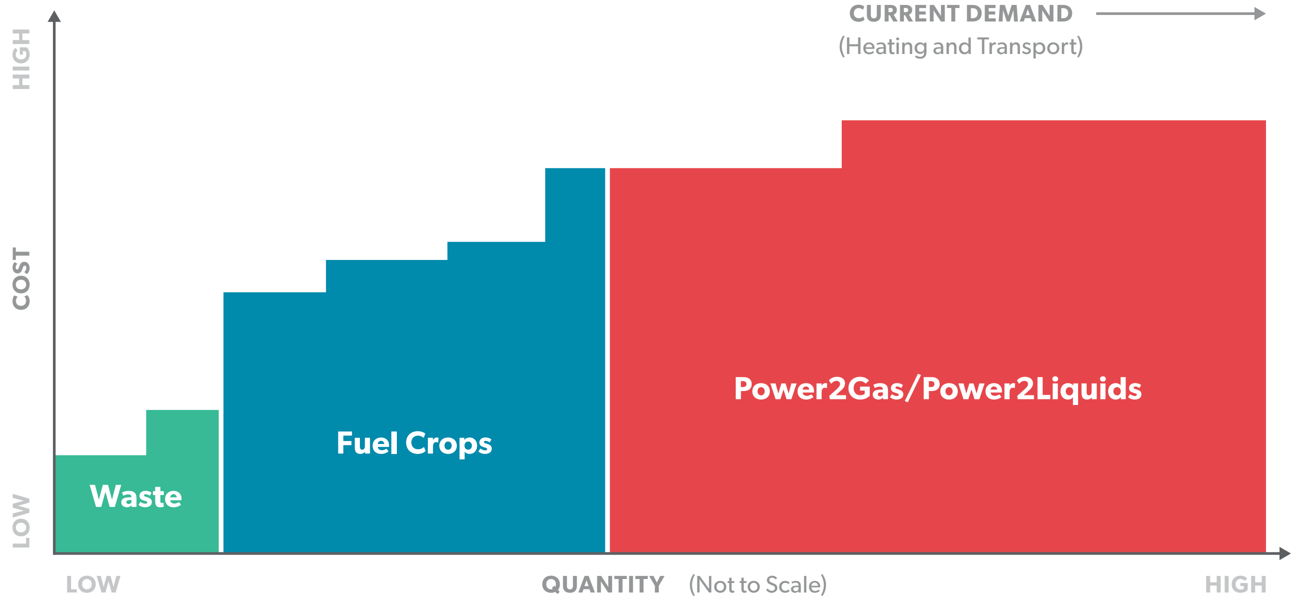


FIGURE 19: SOURCES OF RENEWABLE FUELS

potential sources for both renewable oil and renewable gas, though one of the challenges may be the limited quantities available from less costly sources.

1. Taxonomy of Renewable Fuels

The sources for renewable fuels can be thought of in three categories: waste biofuels, fuel crops, and power-to-fuel technologies, as illustrated in Figure 19.[58] Potential waste sources include used cooking oil for biodiesel, and landfill gas or waste biomass (e.g., food waste, animal manure or wastewater via anaerobic digesters) for natural gas. Some woody biomass may be available as byproducts of agriculture or forestry processes, which can be gasified or perhaps converted to methanol. These are often among the least costly sources for renewable fuels, but because their source is the waste or byproduct of some other process, the quantities available are limited, and in fact are small compared to current demand for natural gas and heating oil.

The second category is fuel crops – biomass that is grown and harvested specifically for fuel. This includes oil crops (rapeseed, soy, palm), other crops such as switchgrass or sugarcane that can be used to produce ethanol or methanol, and many types of biomass which can be gasified. These types of sources are already in use on a relatively small scale, but if they were to be scaled up to produce the quantities necessary for widespread use as heating fuel, the amount of land and resources they would require could put major stresses on agriculture and the environment. In part because of this, the cost of renewable fuels produced from fuel crops will generally be higher than those produced from waste biomass. Also, both the available quantity and the net greenhouse gas emissions impact of fuel crops remain uncertain.[59]

58 There may be some hybrids among these categories, such as combining waste or agricultural feed stocks with P2Fuel technology as a way to facilitate the production of other fuel types.

59 There is a very active debate about the impact of fuel crops on land use and greenhouse gas emissions. Apart from the question of land availability to meet high levels of renewable fuel demand from fuel crops, net greenhouse gas emission reductions are also uncertain, given that fuel crops would likely result in direct or indirect land use changes involving conversion of land areas that are carbon sinks into fuel crop land that would at best be carbon neutral. For a discussion of the literature on this issue see https://farm-energy.extension.org/indirect-land-use-impacts-of-biofuels/.

The third category includes the Power2Fuels technologies introduced above, in which fuels are synthesized using renewable electricity to create hydrogen, are further converted via what is called methanation to methane, and possibly using additional chemical processes to turn methane into liquid fuels. In principle, P2Fuels processes (illustrated in Figures 11 and 12 above), should be scalable to very high volumes, limited only by the availability of renewable electricity and the capital equipment required. There have even been suggestions that P2Fuels pathways might complement a high-renewable power system, taking advantage of cheap or free renewable electricity at times it would otherwise be curtailed; this might lead to relatively inexpensive renewable fuels since the cost of input electricity is a substantial component of their cost.[60] It is unlikely, however, that sufficient surplus renewable electricity would be available if P2Fuels production were implemented at a large scale. Demand for renewable electricity for P2Fuels production would consume otherwise curtailed renewable power in most hours, raising the price until it is consistent with the prevailing power price at other times or the economics of P2Fuels production at higher prices are no longer attractive. Also, the equipment needed to produce P2Fuels – electrolyzers, methanizers and, potentially, CO_2 air capture devices - is costly, so it would not be cost-effective to operate only in the relatively infrequent times when electricity remains very cheap or free. In addition, operational constraints may prevent the kind of flexible operation that may be required to take advantage of periods of excess renewable power generation. Therefore, if deployed at large scale, the electricity used as an input to P2Fuels production will likely be priced at or near the average cost of producing renewable power (which includes their capital costs).

Finally, depending on where P2Fuels processes take place – in theory, electrolysis, methanation and CO_2 capture could occur in different places, but there are also likely synergies for co-location – the manufacturers of renewable fuels would incur delivery charges for the electricity used in the process.

2. Markets for Renewable Fuels

Since renewable fuels that can be used for heating can also be used in other sectors, including transportation and industry, and are easily transportable, the market for renewable heating fuels, like current markets for fossil fuels, will not be local or limited to the heating sector. This will cause prices to tend to equilibrate across sectors and regions.[61] This means that the prices of renewable fuels will be set by market forces working across a geographic region much larger than Rhode Island and economic sectors well beyond heating fuel. It also means that, as with all goods, competitive economic forces will ensure that the least costly production sources will be utilized first and that the last, most costly source needed to meet a given level of demand – across sectors and geographies – will set the price at that level of demand.

Thus, the market for renewable fuels will likely be national or international in scope. Sources of waste biofuels are widespread across the country, but not concentrated in the Northeast and, in aggregate, can supply only a small share of current fuel uses.

3. Supply Curve for Renewable Fuels

For all of these reasons, and because P2Fuels processes are still in their infancy, the availability and the costs of renewable fuels – both liquids and gas

60 For a discussion of the use of surplus renewable energy to make hydrogen or renewable gas to use in power generation, see for example https://physicsworld.com/a/oversizing-renewables-to-avoid-shortfalls/ or https://www.windpowermonthly.com/article/1578773/green-hydrogen-economically-viable-2035-researchers-claim.

61 Fossil prices differ across regions in the United States, in part because of how close fuel production is to fuel consumption, but also due to different fuel standards resulting in different production processes. One would expect some price differences for renewable fuels to occur as well, even though price differences would be limited by the opportunity to sell such fuels into higher priced destination markets.

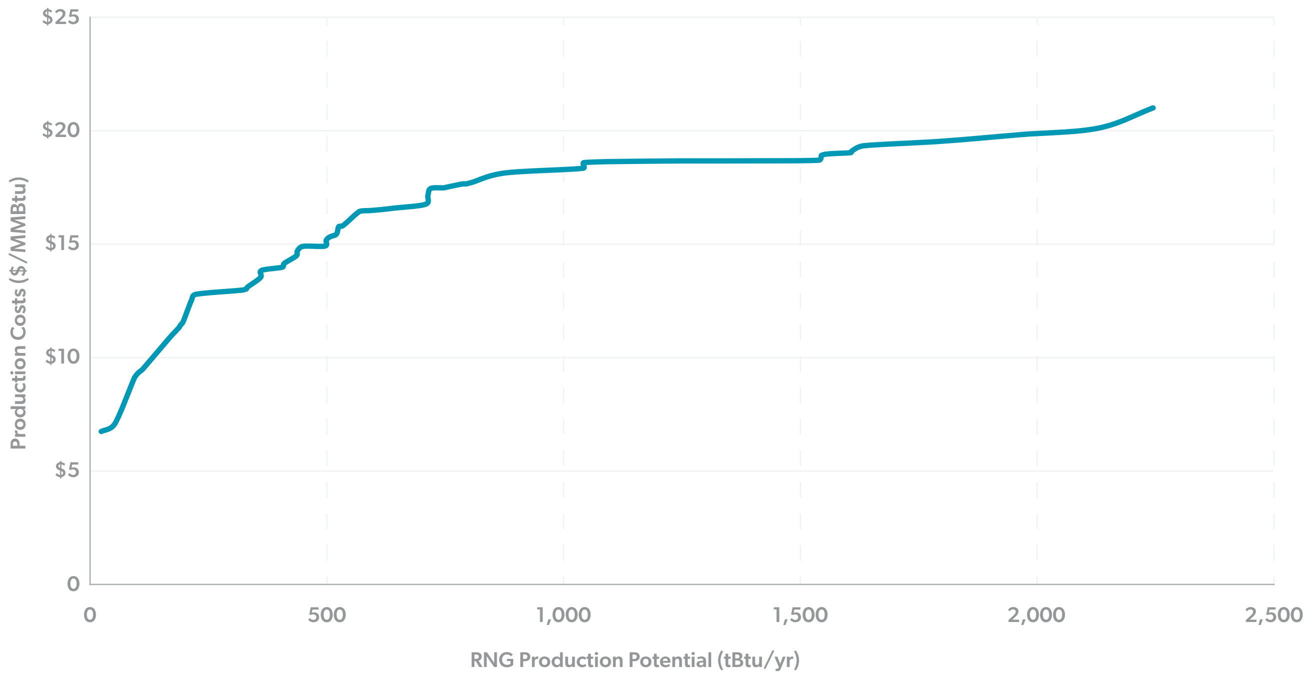


FIGURE 20: AMERICAN GAS FOUNDATION U.S. SUPPLY CURVE FOR RENEWABLE GAS (HIGH RESOURCE POTENTIAL SCENARIO)

Source: Reproduction of Figure 34, Combined RNG Supply-Cost Curve (based on high resource potential scenario), less than $20/MMBtu in 2040, American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reductions Assessment, December 2019.

– in the near term and through 2050 remain highly uncertain. It is likely that only limited quantities will be available at relatively low costs.

For renewable gas, a recent report by the American Gas Foundation estimated the supply of renewable gas available at a cost below $20/MMBtu – which is roughly eight times the current price of natural gas. **Figure 20** reproduces this modeled supply, which reflects the AGF's High Resource Potential Scenario.

As **Figure 20** shows, the analysis by the American Gas Foundation concludes that in its high resource potential scenario, approximately two trillion Btu per year could be produced at a cost of $20/MMBtu or less. The total technical potential to produce renewable gas in that scenario is 4.5 trillion Btu per year, roughly equal to total average annual residential natural gas demand between 2009 and 2018, but only about 25% of total average annual natural gas consumption across all sectors combined.[62] Consequently, especially given that demand for renewable gas would likely not be limited to the residential sector, the price of renewable gas will likely be set by the cost of Power2Gas technology. This cost is estimated using a bottom-up model of the manufacturing cost of renewable gas via Power2Gas, as explained in greater detail in the **Technical Support Document**. Using a variety of sensitivities, it results in an estimated cost of renewable gas via Power2Gas of $30/MMBtu by 2050, with a range between $10/MMBtu and $47/MMBtu. This range is in line with the estimated range of costs for renewable gas derived from various biomass feed stocks, as well as other studies estimating the cost of renewable gas, as illustrated in **Figure 21**.

The analysis of renewable oil is informed by the Power2Gas model, by currently observed costs for biodiesel (B100) in New England and the United

62 See American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emission Reduction Assessment Study, 2 page summary.

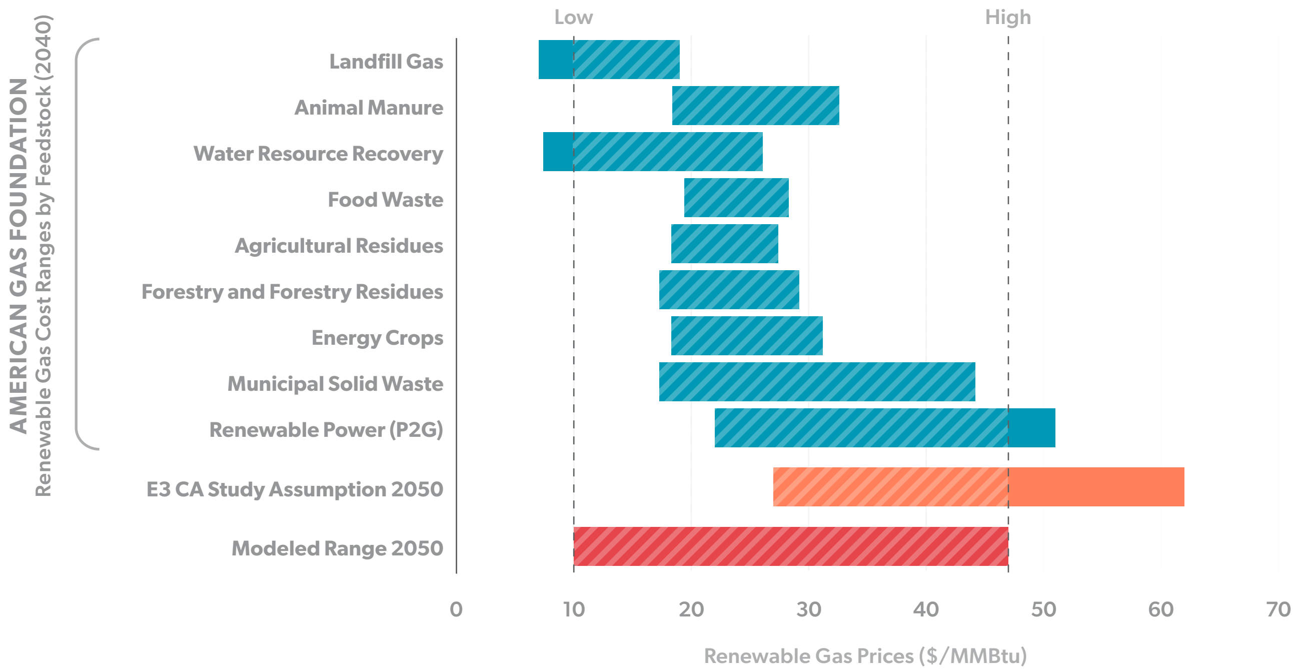


FIGURE 21: ALTERNATIVE COST ESTIMATES OF RENEWABLE GAS

Source: American Gas Foundation, Renewable Sources of Natural Gas, December 2019, E3. Draft Results: Future of Natural Gas Distribution in California, June 6, 2019.

States, as well as by other studies estimating the cost of renewable fuel using Power2Liquids technology, to estimate the potential range of renewable oil cost in 2050. As with renewable gas, limited supply potential from inexpensive sources means the 2050 price of renewable oil is likely to be set by the cost of Power2Fuels technologies, which again here is subject to considerable uncertainties.

At present, the New England B100 price of $2.75/gallon is actually $0.39/gallon lower than the price of diesel, though nationally, B100 is consistently about $0.3-0.8/gallon more costly than diesel.[63] Current biodiesel prices are linked to regular diesel (and underlying world oil) prices and, therefore, provide limited insight into the long-term production cost of renewable oil.[64] But current sources of biodiesel (largely vegetable oils and waste cooking oil) are unlikely to be able to provide the volumes necessary to utilize it widely as a heating fuel, forcing the market to turn to other, more costly sources such as Power2Liquids. This is particularly true considering that biofuels can also be used in the transport sector, which represents an extremely large and relatively price-insensitive potential demand for decarbonized liquid fuels. The cost (per barrel) of P2L has been estimated to be approximately 3.3 times the average cost of the electricity source used to make it.[65] Using a cost of $60/MWh (e.g., low-cost offshore wind power plus transmission costs) would result in a cost of approximately $200/barrel, or roughly $5/

63 U.S. Department of Energy, Clean Cities Alternative Fuel Price Report, January 2020, p.21, which shows diesel and B100 prices between 2011 and January 2020.

64 In addition, biodiesel and other advanced fuels benefit from a number of financial support mechanisms. Biodiesel currently receives an investment tax credit of $1/gallon; several other incentive programs are summarized at https://afdc.energy.gov/fuels/laws/BIOD?state=US.

65 See http://euanmearns.com/lcoe-and-the-cost-of-synthetic-jet-fuel/

gallon.[66] This would represent a little bit less than a doubling of the cost of B100 relative to current diesel prices in Rhode Island.

Since Power2Liquids technology generally converts renewable gas into liquid fuel using an additional production step, it is likely that, per unit of energy, the cost of renewable oil will be slightly higher than renewable gas. This $5/gallon estimated renewable oil cost corresponds to $36/MMBtu,[67] slightly higher than the $30/MMBtu estimated cost for renewable gas. While both renewable gas and renewable oil are materially more expensive than their fossil counterparts, the proportional increase is much larger for gas. The long run cost of renewable oil is likely to be 15%-160% above the current cost of fossil oil, but the long-run cost of renewable gas may be 40%-300% greater than the current fossil gas cost. This is because, on an energy basis, natural gas is currently much cheaper than heating oil. This could have implications for the relative attractiveness in the long run of renewable oil vs renewable gas. If their prices are similar, liquid fuels can have some advantages over gaseous fuels – they are easier to handle, store and deliver, and do not require a costly, long-lived and dedicated delivery infrastructure.

66 Other bottom-up modeled costs are similar. For example, Fasihi et al. estimate the cost of P2G diesel at $160.85 USD/barrel. They also observe that the ratio of diesel to crude oil prices is approximately 1.14, which means that to compare biodiesel to regular diesel prices via the price of oil requires an additional adjustment. See 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, p.255

67 Based on an assumed energy content of heating fuel of 139,000 Btu/gallon. See https://www.engineeringtoolbox.com/energy-content-d_868.html

Analysis of Decarbonized Heating Pathways for Rhode Island

Section IV considers the economic and other factors that may affect the choice of the preferred heating transformation pathway(s) for Rhode Island in terms of the decarbonized heating solutions identified above. Section IV compares the economics of the decarbonized alternatives for a representative residential home, assuming for each technology that the corresponding Bookend Scenario prevails. For example, the cost of heating with an ASHP is evaluated based on the electricity system and power prices that would prevail if all of New England relied on ASHPs for heat. This would cause an extreme electric load peak at the coldest times in winter, and the electric system resources required to meet this peak would result in higher electricity prices than in the other Bookend Scenarios. Similarly, the cost of heating with decarbonized fuels is evaluated based on renewable fuel prices that are consistent with all heating in the region relying on decarbonized fuels. That implies that demand for decarbonized fuels would be high, and so the price must be high enough to bring forth this amount of supply. In addition to considering a "mid-range" cost estimate for each of the alternatives, an uncertainty range around this estimate is built up from uncertainties on both up-front costs and ongoing operational costs. At the end of this section, the scope of the analysis is broadened to consider the impact of decarbonizing the other major energy sectors – current electricity consumption and electrified transportation – in combination with decarbonizing heat (using the same Bookend Scenarios) and the resulting cost implications for consumers' overall "energy wallet" relative to today's costs.

ECONOMIC MODEL RESULTS – SINGLE-FAMILY HOME

Applying the methodology outlined above allows for a comparison of the future economics of the various heating decarbonization solutions. In this section, the results of this analysis are presented for a representative existing single family home from three different perspectives:

- The first perspective presents several Bookend Scenarios, i.e., the analysis assumes that either consumers maintain their current heating fuel and hence volumes of delivered gas and oil remain constant (in the cases examining the economics of renewable oil and renewable gas), or it assumes that all consumers adopt either GSHPs or all ASHPs (with corresponding impacts on electricity prices). These Bookend Scenarios highlight the feedback effects on individual consumers under relatively extreme assumptions about the adoption rates of individual decarbonization solutions. In reality, these Bookend Scenarios are unlikely for a number of reasons, including that the relative cost and attractiveness of decarbonization solutions will likely vary significantly

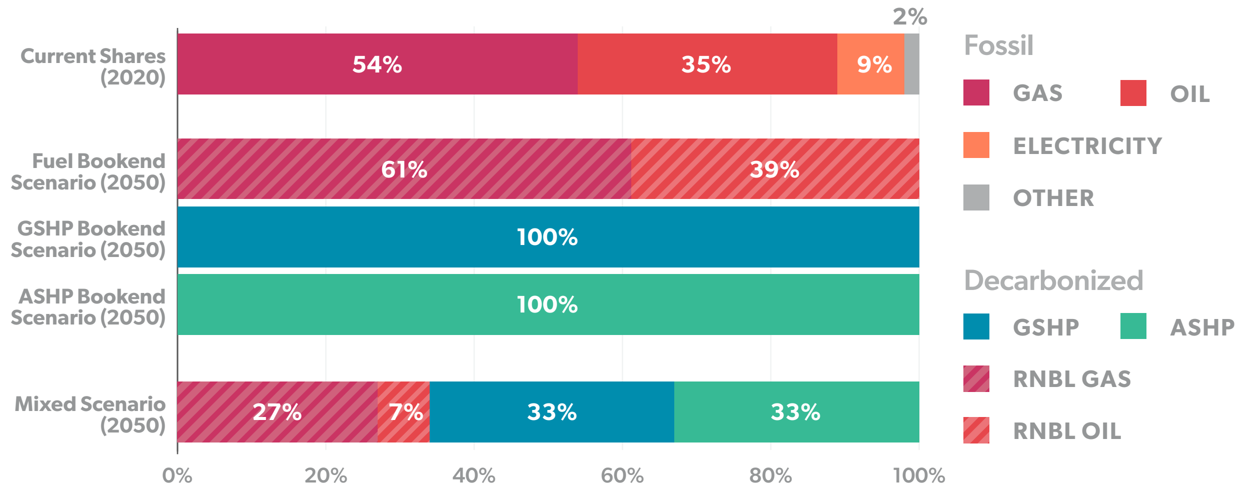


FIGURE 22: HEATING SHARES BY FUEL (NUMBER OF BUILDINGS) CURRENT SHARES VS MIXED SCENARIO (2050)

by building-specific conditions and because of different consumer preferences and other qualitative factors discussed below.

- The second perspective examines the economics of the various decarbonization solutions from a consumer's perspective, assuming an illustrative "mixed" adoption pattern (recognizing that the relative shares of each of the available decarbonization solutions in the future remains highly uncertain).
- Finally, a third perspective uses the mixed adoption scenario to assess how the economics of various decarbonization solutions affect an individual consumer's overall "energy wallet" that compares current costs with potential future costs with each of the decarbonized heat solutions, in the context of a fully decarbonized economy. The energy wallet perspective is instructive since statewide and regional adoption rates of various decarbonized heating solutions will have impacts in particular on electricity prices, which in turn impact other energy related spending, including in the short run current electricity bills and in the longer run likely also spending on transportation assuming personal transportation is decarbonized via a switch to electric vehicles.

Figure 22 illustrates the shares of each heating solution that exist now, in the three Bookend Scenarios, and in the Mixed Scenario.

1. Bookend Scenarios

Figure 23 compares the annualized cost of residential space heating solutions, both fossil and decarbonized, under these Bookend Scenarios for a representative Rhode Island single family home, using projected costs for the year 2050 for alternative heating systems that provide the home's entire heating needs, not just a partial or supplemental system. The traditional carbon-emitting options of fossil natural gas, oil or propane are on the left using projected 2050 costs, and on the right are the decarbonized options of renewable gas, renewable oil or decarbonized electrification with ground-source or air-source heat pumps (or electric resistance).[68] The analysis assumes an annual

68 As noted above, the analysis of renewable gas here provides a good proxy for a renewable hydrogen solution, since the projected cost of renewable hydrogen is generally within the range considered for renewable gas costs (perhaps toward the lower end, since producing hydrogen with P2G can avoid the methanation step). Such a solution might involve either blending hydrogen with renewable gas, or using it as a standalone heating fuel, though in the latter case, the renewable gas analysis does not account for upgrades to the gas delivery infrastructure that may be necessary to accommodate hydrogen.

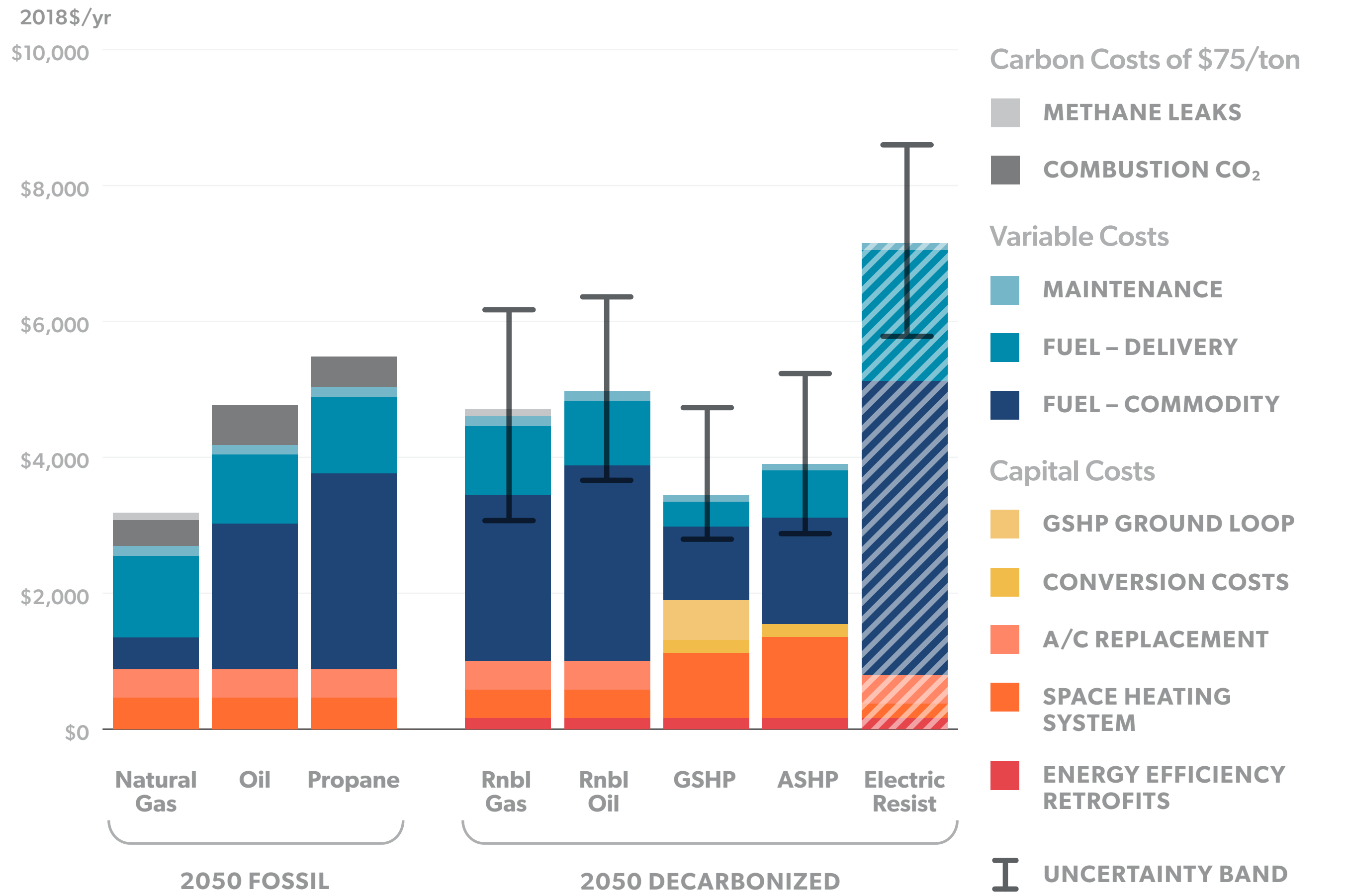


FIGURE 23: ANNUALIZED COST OF SPACE HEATING, SINGLE-FAMILY HOME IN 2050 BOOKEND SCENARIOS (2018$)

Notes: Discounting at 3% to reflect social discount rate. Carbon price $75/ton. Heater capacities: 7.5 ton furnace or boiler with energy efficiency and 9 ton furnace or boiler without energy efficiency (sized to meet two times peak demand), 5.0 ton heat pumps (sized so that the system meets at least 120% of peak demand, with ASHP using supplemental electric resistance heating capacity).* Efficiencies: 93% for gas-fired furnaces, 84% for oil-fired furnace/boiler, 360% for GSHPs, 285% (weighted average based on temperature and load) for ASHPs, and 100% for electric resistance. Prices: natural gas $17.43/MMBtu, oil $4.14/gal, propane $3.83/gal, renewable oil $5.33/gal, renewable gas $42.57/MMBtu; electricity price 23 cents/kWh (GSHP), 28 cents/kWh (ASHP and electric resistance). Additional inputs and data sources can be found in the Technical Support Document. The modeled heat pump size differs from typically installed heat pumps today as it is sized to meet all heat requirements except on the most extreme days. Design capacity is slightly above the 100-115% size design suggestion by NEEP (See NEEP, Guide To Sizing & Selecting Air-Source Heat Pumps in Cold Climates rev. 12/7/18, p.5 (Full System Replacement)

heat demand of 76 MMBtu per year, which is 15% below the current average of 89 MMBtu per year for single-family homes in Rhode Island, reflecting cost-effective building efficiency improvements assumed to be implemented for essentially all homes by 2050. The "representative" home modeled is not an actual home, but rather represents a home with the average annual heating energy demand in the state (calculated by dividing total heating energy consumption by the total number of single family homes). Still, given the Rhode Island housing stock, a "representative" home would be at least several decades old with 1,500 to 2,000 square feet of livable space. The impact of cost-effective energy efficiency measures is based on the range of reported impacts of weatherization programs – expressed in percentage improvements over existing heating demand – from weatherization programs in New England. The precise amount of heat needed for any particular home will have little impact on the relative costs of the alternatives, and the broad conclusions from this analysis apply across a wide range of building sizes and heat needs.

Figure 23 includes a breakdown of the annualized cost into operating costs (in shades of blue) and annualized capital costs (in shades of orange). Operating costs are mostly the cost of "fuel" – fossil natural gas, oil or propane for the carbon-emitting options, versus renewable gas, renewable oil or electricity for heat pumps for the decarbonized options. The fuel costs are split roughly according to the cost of the commodity itself (lighter blue) vs the cost of delivering that commodity to the building (darker blue). The annualized capital cost of the heating technologies (which includes installation cost) is shown in shades of orange. Furnaces or boilers must be replaced periodically, but the cost is modest since the equipment and installation are reasonably simple and modifications to the home are not necessary. For heat pumps, the capital cost is larger because the heat pump equipment and installation can be more costly, and may also require additional components – a ground loop for GSHP, and additional costs for adapting the existing building to a different way of providing heat (e.g., ductwork, electrical upgrades).[69] The capital cost comparison also includes the cost of replacing a central air conditioning system if a furnace or boiler is used; that cost can be avoided with a heat pump, which also provides cooling.

To allow for a better comparison of fossil with decarbonized heating options, **Figure 23** also includes an assumed cost of carbon emissions. Including such a cost is important since it reflects actual costs to society of continued carbon emissions. In addition, it is likely that by 2050 (and earlier), fossil fuel prices faced by consumers will reflect these costs, for example in the form of a carbon tax or fee, cap and trade program, or other mechanism. The analysis uses a cost of $75/metric ton, in line with current benefit-cost analyses performed by the state.[70] This cost is applied to the net GHGs from the combustion of fuel (assumed to be zero for the renewable fuel options, which implies that the fuel is carbon neutral),[71] and also the GHG contribution of methane leaks (at the current leak rate).[72] Renewable gas includes the leak component as well, since even if the source gas itself is carbon-neutral, methane leaks still create GHG

69 The idiosyncrasies of individual buildings may have a substantial impact on the relative economics on a case-by-case basis. E.g., some particular building may find it much more costly to convert to a heat pump due to the need for extensive ductwork and a major electrical system upgrade; a different building may not face such costs at all. Recognizing these possibilities, and acknowledging that it is very difficult to obtain representative costs for such retrofit requirements due to the wide diversity of circumstances in individual buildings, the economic analysis assumed that replacing a fossil heating system with a heat pump would require about $5,000 in upgrades (e.g., ductwork and electrical) to enable the transition.

70 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: 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.

71 As described above, most renewable fuels using biological feed stocks are currently not carbon-neutral. The long-term potential to achieve (near) zero net carbon emissions depends on both the feedstock itself and the conversion process. For example, overall carbon intensity can be very significantly reduced if transportation and process energy used in the production of biofuels is itself carbon-free (such as renewable electricity).

72 The analysis assumes a distribution system leak rate of 2.7%, from Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study, September 2019, Stockholm Environment Institute, et al. It uses a 100-year global warming potential for methane of 30, based on the U.S. EPA range (U.S. EPA, "Understanding Global Warming Potentials", available at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials), and adjusts for the different masses of methane vs. CO_2. Successful efforts to reduce gas leaks would reduce the costs of methane leaks correspondingly.

emissions since methane is a much more potent greenhouse gas than CO_2.

Figure 23 also indicates an uncertainty band around the mid-range estimate, illustrated by the vertical black line that shows 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 heat pumps, the high initial cost makes up a substantial share of their total annualized cost, whereas renewable fuels have low initial equipment costs but fuel costs that are both substantially higher and also highly uncertain. GSHPs have even higher initial costs than ASHPs, though annualizing the cost makes the difference less pronounced, given that GSHP equipment life is longer (it is housed indoors) and ground loop costs are spread over a longer operating life.[73] These higher upfront costs are offset by lower operating cost of GSHP: due to higher average efficiency (especially during cold temperatures as explained above), GSHPs use about 20% less electricity overall, and if ASHP is adopted widely, it would likely raise power prices.

Overall, this analysis shows that among the various decarbonization solutions for a representative single-family home, while there are some differences in the mid-range estimated costs, the uncertainties are significant and the uncertainty bands are largely overlapping. The ranges of annualized costs for all four decarbonized heating solutions are broadly overlapping (around \$3,000-\$5,000 per year). This means that no one technology is a clear winner based on economics, making it difficult to choose one of these decarbonized pathways over the others given the information that is available now. Ground-source heat pumps appear nominally to be the least costly option, followed by air-source heat pumps and renewable gas. However, the range of uncertainty about the future cost of each of these heating options exceeds the differences in the nominal cost estimates between them, indicating that an alternative (but very reasonable) set of assumptions about how the costs of these technologies may evolve over the coming decades could lead to a different ranking.

It is also worth comparing the estimated cost of decarbonized heating with the cost of continuing to use fossil fuels for heat. Using projected fossil prices for 2050, the decarbonized heating solutions are generally more costly than natural gas heating, but could be competitive with heating oil and propane. Decarbonized heating with renewable fuels is likely to be more costly unless these renewable fuels end up near the low end of their cost uncertainty band. If carbon costs (here illustrated at \$75/tCO_2) are included, the decarbonized alternatives become somewhat more competitive. Still, an overarching observation is that the range of uncertainty makes it difficult to draw any firm conclusions, either comparing decarbonized solutions or comparing those with the continued use of fossil heating (acknowledging that there is also uncertainty about future fossil fuel costs, not characterized here). Current fossil heating costs are modestly lower than the projected 2050 costs (see **Figure 10**), so it is reasonably likely that – for the average consumer – decarbonized heating may increase 2050 heating costs from their current level, *but perhaps not by much more than costs would rise with continued use of fossil fuels.* Importantly, the actual impacts of decarbonizing heating systems may differ significantly for individual consumers, due to the idiosyncrasies of individual buildings. And even if increases in heating costs due to decarbonization are modest on average,

73 Another advantage of GSHP is that it does not require a backup heat system to cover peak heat needs in the coldest weather. With an ASHP, by contrast, output is lowest when heat demand is highest, so a backup system is needed. However, this backup can be provided by electric resistance heat, which has little operating penalty in cold weather and has small up-front cost.

policy – discussed below – must take into account that cost increases could be more pronounced for some consumer groups, and that even modest cost increases may put a significant burden on already disadvantaged consumers, in which case mitigating policy measures will be even more important.

To understand some of the other factors that may drive a heating sector transformation, it is useful to consider another perspective in addition to the societal economic view presented above – that of a consumer contemplating the economics of alternative heating systems. For a variety of reasons, consumer behavior often does not reflect the long-run economics characterized above. Rather than choosing the alternative with the lowest long-run total cost, consumers generally require energy investments to pay back any up-front investment within just a few years, or they will decline to make the investment.[74] This is a very real issue for a consumer contemplating a switch from fuel-based heat to a heat pump, which can require tens of thousands of dollars of up-front investment and potentially significant modifications to the home (ductwork, electrical upgrades), vs. a few thousand dollars to replace the old fuel-fired boiler or furnace with a new one.

The higher up-front costs of heat pumps might lead customers to remain with the fuel-burning solution (whether the fuel is fossil or renewable) even if the heat pump's much lower operating costs offer significant lifetime savings. This effect is further exaggerated for ground source heat pumps which have the additional ground loop cost. This suggests that even if heat pumps do have lower long-run economic costs, significant policy intervention and program support may be required to induce customers to adopt them. Such policy intervention could take the form of direct incentives or no-to-low cost capital financing that reduce the up-front costs. For example, a GeoMicroGrid may not only reduce the up-front cost of GSHP, but utility ownership of the ground loop could help to reduce the initial cost barrier.

2. Mixed Adoption Scenario

The Bookend Scenarios analyzed above assume that all New England heat is provided by a single technology (or that current fuel types are maintained in the case of the renewable oil and renewable gas scenarios, respectively) to illuminate their potential impact on other systems. Of course, the actual decarbonized future will almost certainly include a mix of the candidate technologies. To reflect such a more realistic outcome, while still incorporating the feedback effects on electricity prices and gas delivery costs discussed above, a Mixed Scenario, in which the New England heating sector is decarbonized using a mix of the candidate technologies, was also developed. Of course, the particular mix analyzed here reflects only one possibility, but it does illustrate some important potential effects. For this illustrative Mixed Scenario, half of existing gas customers are assumed to electrify their heating, along with 80% of oil customers and essentially all customers using other fuels.[75] In aggregate, two-thirds of customers switch to electric heat pumps, split equally between ASHP

74 This does not necessarily imply that customers are behaving irrationally in such situations. Such a high investment threshold may reflect, for example, the personal disruption associated with a construction project; the possibility that the homeowner may move within a few years and thus would recoup only a few years' operating cost savings; or the fact that consumers' financing costs are typically much higher than the low discount rate used for the societal perspective above.

75 This is just one assumption regarding the shares of customers who may electrify; it is not intended as a prediction of customers' switching propensity based on their existing fuels. But a lower electrification rate for gas customers might result from the lower current cost of gas heating vs. other current fuels, and perhaps some customers' desire to keep gas as a cooking fuel rather than from the lack of available renewable oil. In fact, considering building efficiency improvements and the potential for customers to use a heat pump to cover just part of their heat needs, retaining their fossil system as backup perhaps as an interim solution, there are many different ways in which decarbonization could reduce the demand for gas and other traditional fuels. This Mixed Scenario yields insight into such alternative scenarios as well.

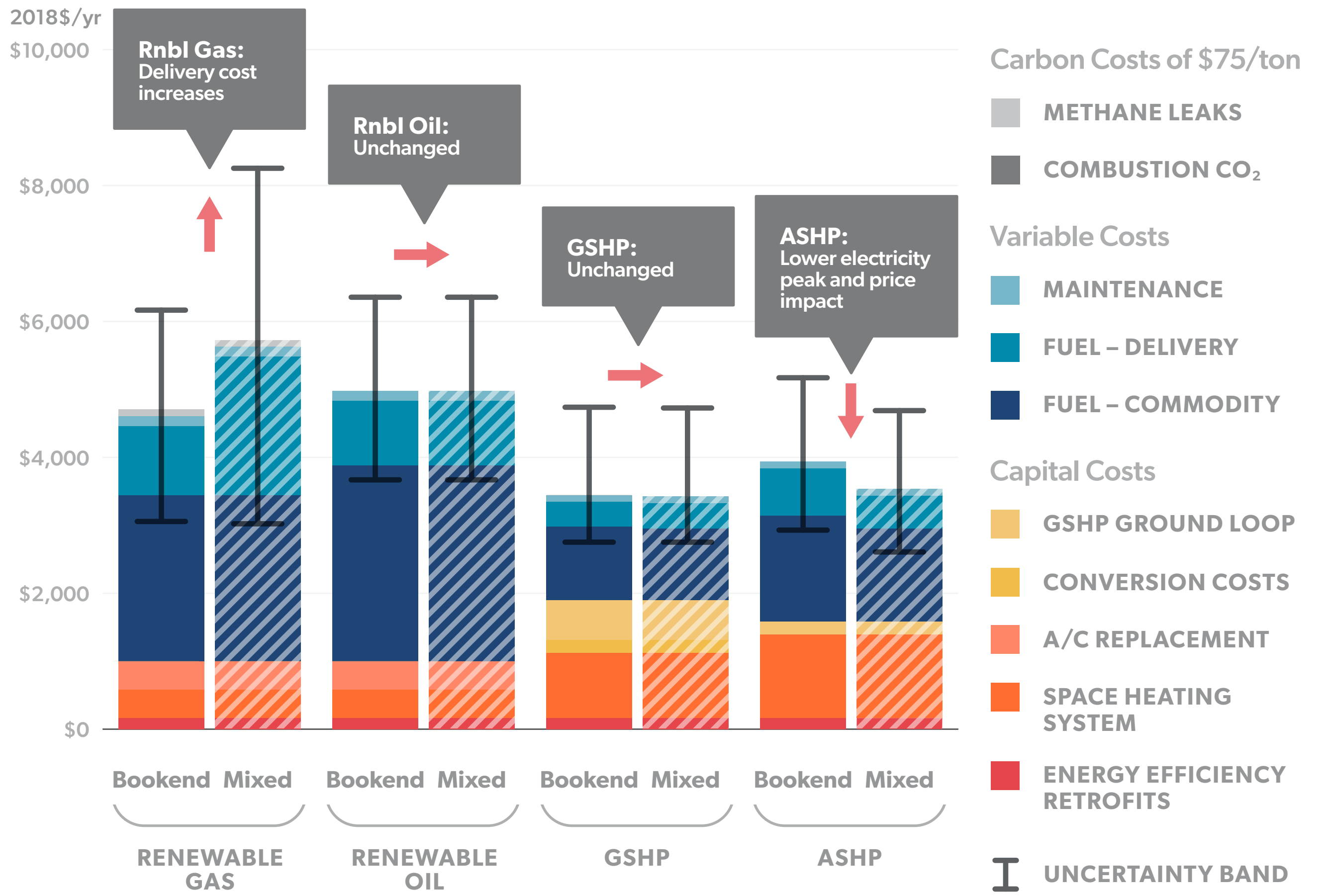


FIGURE 24: ANNUALIZED COST OF SPACE HEATING, SINGLE-FAMILY HOME IN 2050 MIXED SCENARIO VS. BOOKEND SCENARIOS (2018$)

and GSHP. Those customers keeping their existing fuel type would burn a renewable version of that fuel in 2050. Figure 22 above illustrates the current heating fuel shares, as well as the shares assumed in the Mixed Scenario.

Figure 24 compares how this Mixed Scenario changes the results from the Bookend Scenarios examined in Figure 23. Electric demand and price in the Mixed Scenarios are similar to the GSHP Bookend Scenario, so GSHP costs are very similar, and ASHP costs are lower than in their respective Bookend Scenarios.

The most substantial impact is on the cost of heating with Renewable Gas. Since volumes delivered through the gas distribution system are substantially lower in this scenario (and assuming the cost of maintaining and operating the gas delivery system is essentially fixed), the delivered price of Renewable Gas would increase markedly. Figure 25 provides a simple illustration of the potential dynamics affecting delivered gas prices in a decarbonized future. The left side of the figure shows fossil gas prices now and projected in 2050 at current delivery volumes. The right side illustrates how the future delivered cost of 100% renewable gas might be influenced by the gas commodity cost (here, assumed to be $30/MMBtu independent of the amount delivered)[76] and reduced delivery volumes. At current volumes, the delivery

76 As noted above, the commodity price of renewable gas in Rhode Island will likely not depend on local demand, since a future renewable gas market is likely to be regional or national in scope.

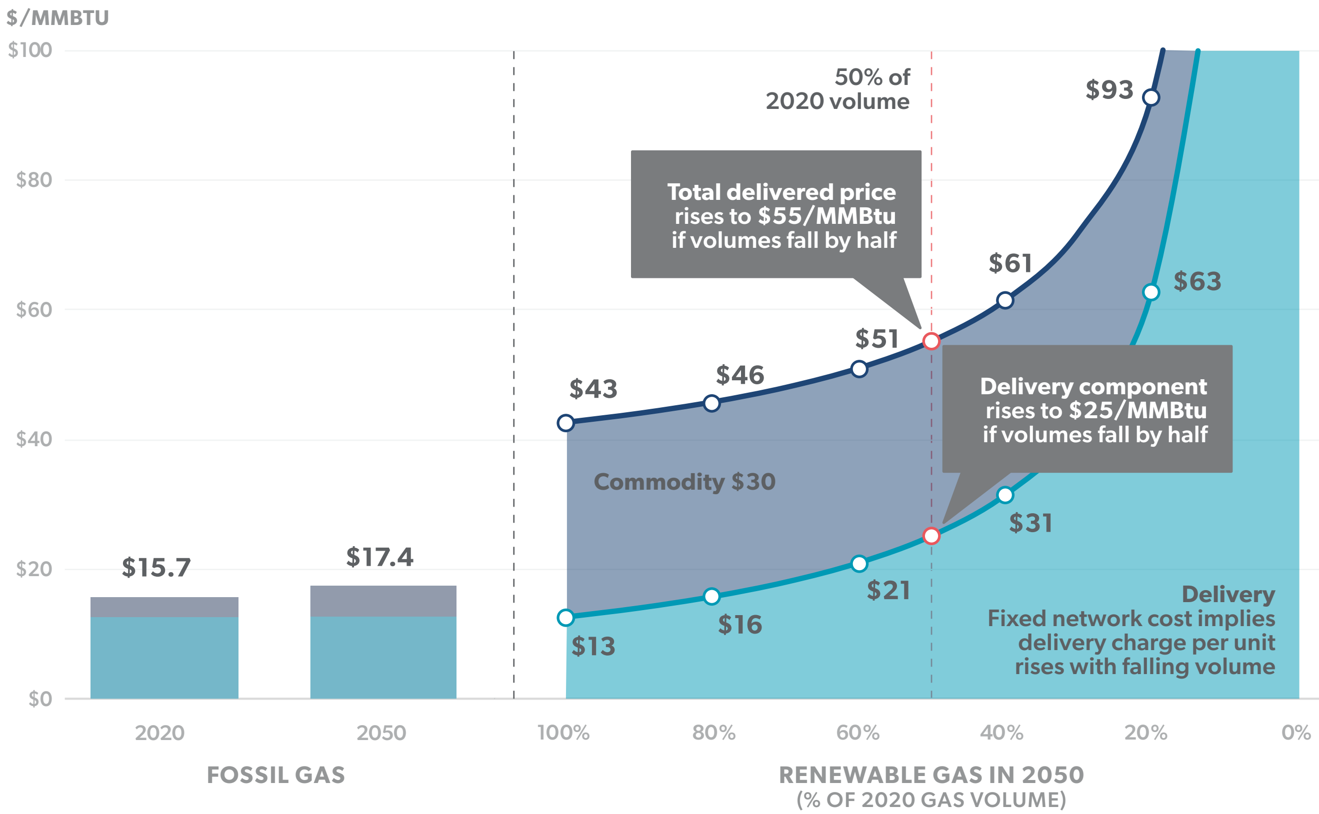


FIGURE 25: DELIVERED PRICE OF GAS: 2020 FOSSIL GAS VS POTENTIAL 2050 RENEWABLE GAS (2018$)

charge would be $13/MMBtu as it is today, resulting in a $43/MMBtu delivered price of renewable gas. If delivery volumes decrease, the delivery cost per unit would rise, since total distribution system costs would not change. For example, if volume fell by half as assumed in the Mixed Scenario, the delivery charge component could double, with the delivered gas price reaching $55/MMBtu – over three times the current delivered gas price.

A reduction of half or more in gas volumes may not be a particularly extreme assumption; the efficiency improvements assumed here alone would reduce gas demand by 15%, even with no gas customers switching to a different heating solution. This points out an important potential challenge for the gas system: Any volume of gas sales lost to electrification (or to improved building efficiency, or even to renewable oil which does not have a fixed-cost delivery network) will increase the delivered price of gas as the fixed distribution costs are spread over less gas. This could prompt further volume loss and an upward cost spiral for remaining customers. In turn, this would impose significant risks for customers who cannot easily switch away from gas, as well as for the gas utility. The most obvious way to avoid these issues would be to retain most of the gas volume while decarbonizing the gas. Other approaches could include reducing delivery system costs as volumes fall (e.g., by concentrating losses in some parts of the system and pruning those branches entirely), or sharing the costs of the gas infrastructure more broadly across all "energy" customers, acknowledging the widespread social benefit of decarbonization while protecting individual customers.[77]

77 However, even if gas system costs are spread more broadly across customers, it will be important to continue to monitor the mostly fixed costs of maintaining the gas system. This must be compared with the cost of alternative solutions, such as electrifying all remaining gas demand (including the infrastructure requirements that entails), to ensure that the approach pursued is best for consumers overall.

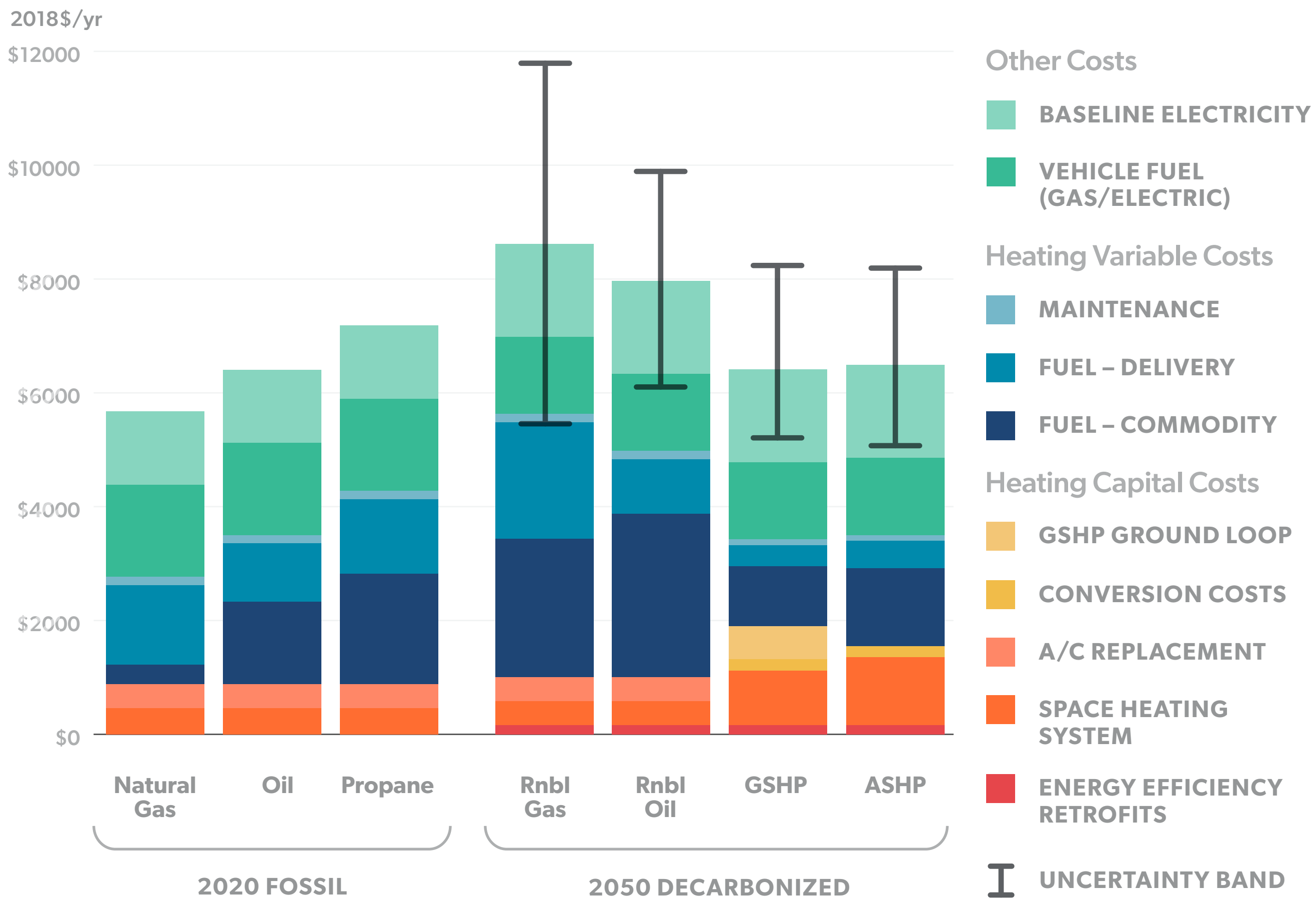


FIGURE 26: TOTAL ANNUAL ENERGY WALLET COMPARISON FOR SINGLE-FAMILY HOME, 2020 VS 2050 MIXED SCENARIO (2018$)

Note: Uncertainty band reflects uncertainty on heating costs as above, plus the effect of electricity price uncertainty on other end uses. Gasoline price excludes federal and state taxes. Water heating cost is not broken out explicitly, though to the extent electricity is currently used for water heating, this is included implicitly in Baseline Electricity usage.

3. Energy Wallet

It is also important to recognize that heating is only one element of a representative consumer's overall energy wallet, which also includes spending on traditional electric end uses and transportation. Figure 26 considers a customer's total energy wallet comparing current energy expenditures across all sectors on the left with a 2050 projection that shows the cost of various decarbonized heating solutions combined with the average cost of charging electric vehicles and traditional electricity consumption. This analysis assumes that light duty vehicles are fully electrified across New England, and that electricity and gas prices are consistent with the Mixed Scenario that employs a mix of decarbonized heating technologies, projecting a plausible future. One notable feature of this comparison is that even though total costs for decarbonized heating may be higher than some forms of fossil heating, and electricity prices are likely to be higher with a decarbonized grid, consumers will not necessarily spend significantly more in total energy costs than they do today in a fossil-fuel based environment. Partially offsetting any increase in the cost of heating for some customers, electric vehicles are more efficient, making it somewhat less costly to "fuel" an automobile with electricity than it is today with gasoline, even though the 2050 decarbonized electricity price is higher than today's price. Still, the energy wallet perspective does not change the fundamental conclusion above. The uncertainty in future costs still outweighs the relatively small differences in expected costs across options (and relative to today), and no single heat decarbonization approach is clearly preferable.

4. Conclusions for Existing Single-Family Home

In sum, for a representative detached single-family home – the most common building type in Rhode Island – a quantitative comparison of annual heating costs for the various decarbonized solutions suggests that, at least according to what can be known now, no single solution provides a clear economic advantage over the others. Rather, which option will have the lowest annual heating costs depends on how several uncertain factors – including the availability and price of renewable fuels and renewable electricity, the installed cost and performance of electric heat pumps, the cost of installing ground loops, etc. – evolve over the coming decade. Any state-level policy promoting decarbonization of the Rhode Island heating sector must take this uncertainty into account.

IMPLICATIONS FOR SPACE HEAT IN LARGER BUILDINGS

The representative single-family residential home analyzed above represents the most common building type in Rhode Island, at the low end of heating demand on a "per-building" basis since they are smaller buildings. There are a significant number of larger buildings in the state as well, both larger multi-family residential buildings and commercial buildings, and of course they must also be addressed in order to decarbonize the heating sector. The same issues discussed above regarding existing vs new buildings tend to apply for larger buildings as well. That is, building efficiency is relatively straightforward and very cost effective for new buildings, and can dramatically reduce the need for heat in those buildings. But with few new large buildings being constructed and many existing large buildings remaining in use in the state, the heating sector transformation among larger buildings must also focus for the most part on retrofitting existing buildings. Also, as with single-family homes, larger buildings may have some relatively low-cost and cost-effective opportunities to improve building energy efficiency; this will help reduce overall customer costs, but cannot approach full decarbonization. Large buildings will still need heat and that heat must be decarbonized.

The basic decarbonization pathways described above – decarbonized electrification with heat pumps and decarbonized fuels – are also relevant for medium and larger buildings, though the long-run cost tradeoffs, relative to each other as well as relative to typical fossil heating systems, may differ. This is a result of their different scale, different heating (and cooling) equipment with different capital costs and operating efficiencies, and thus different tradeoffs between renewable fuel solutions with lower capital cost but higher operating costs, vs. heat pump solutions with relatively higher capital costs, and often some building conversion costs to reconfigure the building to heat with a different system.

To represent the potential tradeoffs, **Figure 27** shows a comparison of the economics of alternative decarbonization approaches for a stylized larger building. This example uses an average sized commercial building in New England (14,250 square feet), which would correspond to a medium-sized office building. Heating demand is based on Buro Happold's analysis, which estimated that commercial buildings currently consume 38,305 Btu/sq. ft. annually; like the residential analysis above, this is reduced by 15% for assumed building efficiency improvements, yielding an annual heat

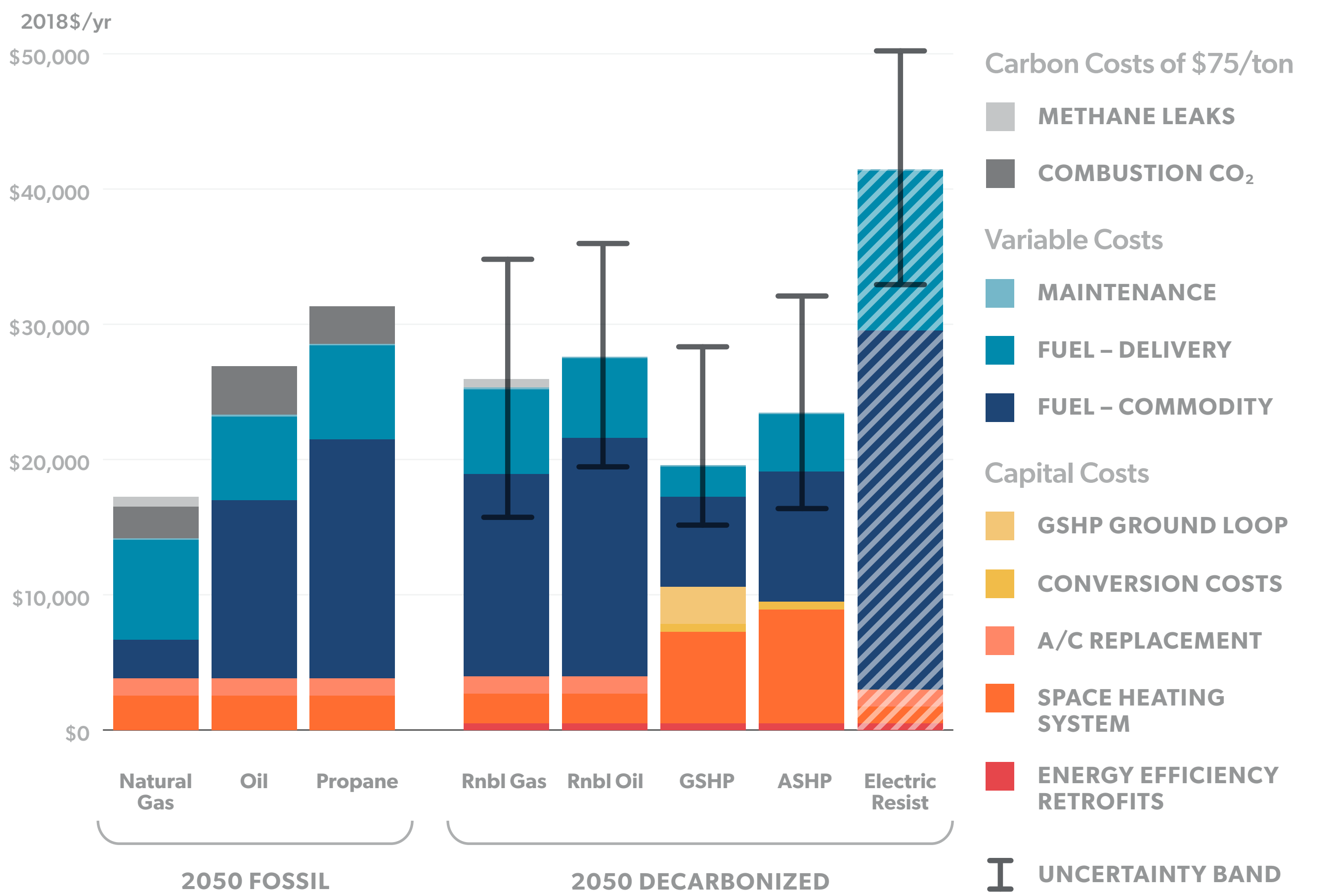


FIGURE 27: ANNUALIZED COST OF SPACE HEATING, STYLIZED LARGE BUILDING IN 2050 BOOKEND SCENARIOS (2018$)

demand of 464 MMBtu. Heating equipment is more costly because it is larger, though it scales up slightly less than proportionally; in particular, the ground loop cost for GHSP is assumed to exhibit declining unit costs for larger installations. Many of the factors do not depend on the size or type of building. For example, ASHPs face the same declining efficiency in cold weather and the price of renewable fuels does not depend on building size. Similarly, renewable gas leaks contribute to GHG emissions and the per-unit cost of gas distribution rises if the gas volume delivered declines. Still, **Figure 27** shows relative costs that are very similar to those in **Figure 23** for a single family home. Heat pumps have much higher capital cost but lower operating costs; the decarbonized options are generally more costly than natural gas and broadly on par with the cost of oil and propane; and the uncertainty ranges on the decarbonized options overlap considerably.

Since larger buildings tend to be more idiosyncratic, a comparison like this may be less broadly applicable than the analysis above for a representative single family home. But some additional observations may be possible. For instance, because large buildings often need some cooling even in the heating season, there may be some waste heat available that could provide a useful heat source for a heat pump – either to heat a different part of the building or to store for a later time. Large buildings may also offer some flexibility, e.g., to convert part of a building at a time (such as converting one or more floors of an office tower as it is remodeled between tenants), and to connect different heating and cooling sources simultaneously to the building's internal distribution systems. As an example, the hot water loop in a building could be configured with both a boiler and a heat pump, which can trade off and supplement one another in operation, with usage potentially transitioning from one to the other over time. Because the heat needs are greater in larger buildings, higher capital cost solutions (such as heat pumps and possibly GSHPs) may be relatively more attractive since there are larger operating costs to be saved, and there may be scale economies in equipment and installation costs.

WATER HEATING

As shown above, domestic water heating represents more than 15% of total energy demand in residential buildings in Rhode Island and moderately less in commercial buildings, making it the second most important source of heating demand. This section considers the relative costs of various decarbonized approaches to water heating. Most of the options are similar to existing water heating approaches, but involve decarbonizing the fuel – renewable gas instead of natural gas or renewable oil instead of heating oil – or using emissions-free electricity in an electric resistance water heater. Electric heat pump water heaters represent a relatively new and promising alternative to traditional electric resistance water heaters. These (air-source) heat pumps integrate the heat pump with the water tank, drawing heat from the surrounding (and typically conditioned) space to heat water in the tank. While a heat pump water heater also utilizes electricity, it does so much more efficiently than an electric resistance heater.

Figure 28 compares the annualized cost of several water heating solutions for a representative single-family home: two fossil options (natural gas and heating oil) and four decarbonized options: renewable gas, renewable oil, electric resistance and electric heat pump. As shown, annualized water heating costs with an electric heat pump are expected to be lower than the other decarbonized options, lower than fossil oil, and comparable to natural gas if carbon costs are included. Although it has slightly higher capital cost than most of the other options, its variable operating cost is much lower, largely because of the efficiency with which it uses electricity. This results in electric heat pumps having not only a lower total annual cost relative to the other decarbonized technologies, but also a notably short payback period of less than two years relative to those other decarbonized technologies. This suggests that electric heat pump water heaters may be the most cost-effective decarbonized water heating alternative in the long run, as well as an attractive energy investment opportunity from a customer's perspective, given their short payback period. Moreover, since this analysis conservatively uses cost and efficiency parameters for heat pump water heaters available today, improvements over time for this still relatively immature technology could make heat pump water heaters relatively more attractive in the future.[78]

The above analysis assumes the choice of water heating solution is independent of the choice of space heating. In reality, the two choices are potentially linked. Since essentially every building in Rhode Island is connected to the electric system (and will be in 2050), a heat pump or electric resistance water heater can be used with any space heating technology. This may not be true for water heaters using gas or oil. If space heating is converted to an electric heat pump, maintaining the gas distribution

78 One potential impact whose effects are not yet fully understood and thus not included here is the potential impact on space heat requirements if – as is typically the case – a heat pump water heater is installed in conditioned space and thus draws heat from inside the building. This could increase the total space heating needs in winter, adding to the cost of space heating. This effect, if present, would work in the opposite direction in summer to reduce the building's cooling needs, particularly if there is a way to circulate the cooled air within the building.

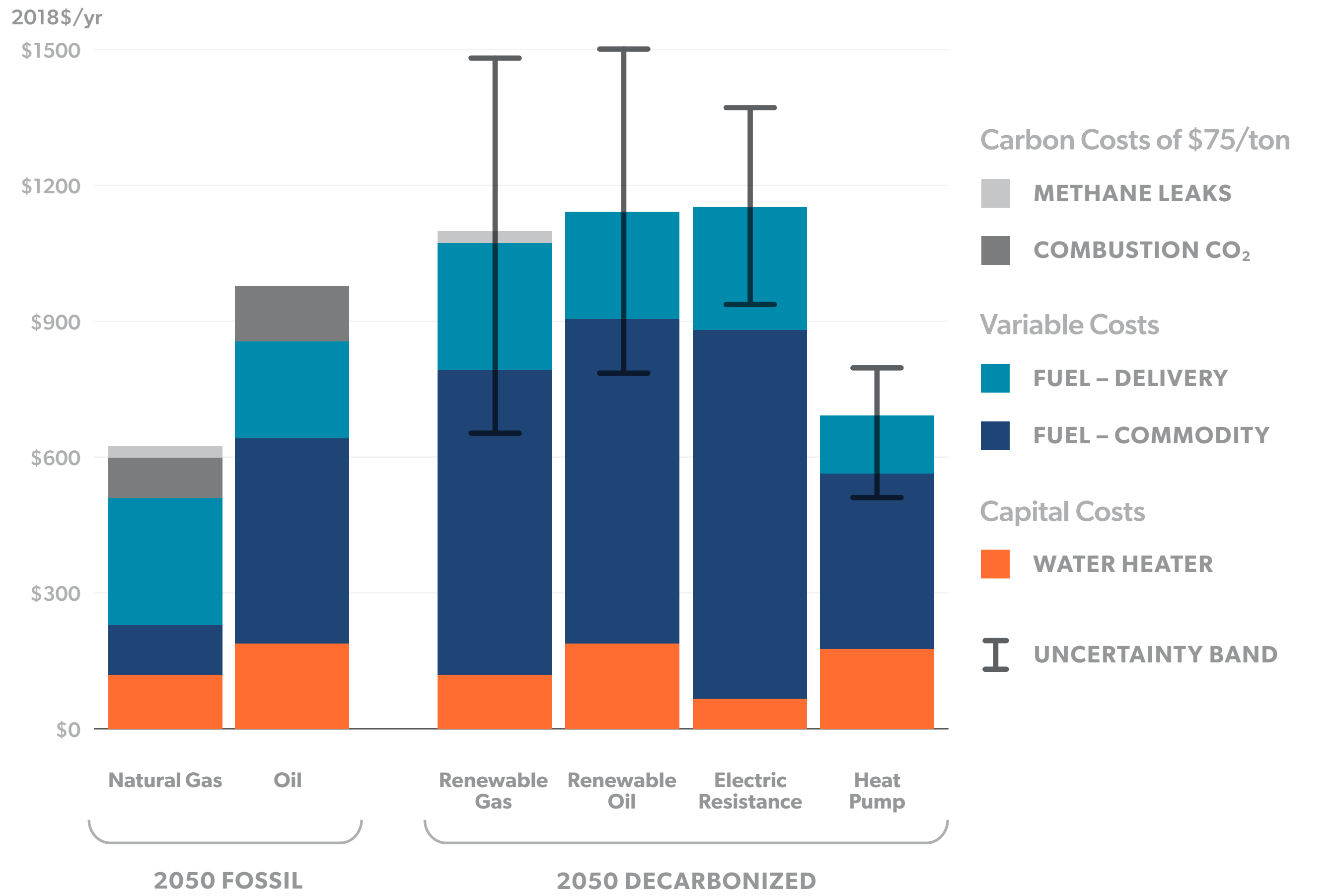


FIGURE 28: ANNUALIZED COST OF WATER HEATING, RESIDENTIAL IN 2050 (2018$)

Notes: Assumes 50-gallon capacity, 15 million Btu annual consumption, and a $75/metric ton carbon price. Efficiency assumptions: 67% for gas water heaters, 95% for resistance water heater and 200% for heat pump water heaters.* Price assumptions: $17.4/MMBtu for natural gas, $4.1/gal for oil, $42.6/MMBtu for renewable natural gas, $5.3/gal for renewable oil, and $0.23/kWh for electricity. Assuming 5% discount rate and an average economic life of 13 years for all technologies except for heat pump water heaters (10 years). Data sources in Technical Support Document. ENERGY STAR® Residential Water Heaters: Final Criteria Analysis, April 1, 2018.

connection (or an oil tank) just for water heating may be much less cost-effective. This may further increase the potential for heat pump water heaters.

In larger buildings, such as large multi-family apartment buildings and large commercial office buildings, water heating systems, like those for space heating, tend to be more idiosyncratic and specific to the particular building. The qualitative tradeoffs for water heating would generally be similar, though the larger scale could enable cost savings or improved efficiency in heat pump water heaters. In some buildings, water heat is currently integrated with the space heating system, and thus might be addressed with the same decarbonized system as space heat.

INDUSTRIAL HEAT

Beyond the residential and commercial applications for space and water heating discussed above, Rhode Island's industrial sector also requires heat, which must be decarbonized as well. The state's industrial sector accounts for approximately 15% of total energy use. Although detailed information is not available on the breakdown of energy uses within the industrial sector, some of it is for space and water heating for buildings (much like in residential and commercial buildings), some is for industrial process heat needs, and some fuel may also be used as a feedstock. That said, Rhode Island's industrial sector as a whole is not characterized by large industrial sectors where process heat is an important input to production (such as steelmaking), nor as feedstock (fertilizer or plastics). This suggests that a substantial portion of industrial sector heating needs may be for space and water heating. Where this is the case, the decarbonized solutions and their relative attractiveness discussed above for larger buildings would apply similarly to industrial needs.

Beyond space and water heat in industrial facilities, there is also an array of specialized industrial process heat needs and applications that may go beyond the technologies discussed so far.[79] These can vary widely, with the type of heat required and the technologies able to provide it often being highly specific to the particular industrial process. Heat pumps can only provide relatively low-temperature heat; while this is adequate for space heating, it is not well suited for most high-intensity industrial process heat needs. For some industrial applications that require intermediate temperatures, electric resistance heat may be useful, though whether a heat source can be utilized in a particular instance is a function not only of the temperature it can provide but also how the heat source can be physically integrated with that particular industrial process. Very high temperature applications typically require burning fuel which, if it is to be decarbonized, would require renewable gas or oil, or possibly renewable hydrogen. Other applications that can use induction, lasers, microwaves, etc. likely exist but will tend to be less common and the opportunities are highly specific to the particular application in question.

Because industrial process heat needs tend to be very specific to particular industrial applications, the availability and cost of decarbonized solutions is also likely to be process-specific. In many instances where natural gas or fuel oil are used today, it should be possible to substitute renewable gas or renewable oil. Renewable (green) hydrogen could play a more important role in the industrial sector than in the residential and commercial sectors. Unlike in those sectors, hydrogen could be stored on-site or potentially delivered via dedicated pipelines to targeted industrial sites that have large, concentrated demand. Given the diversity of industrial applications and the sparse information about both current industrial activities and especially how decarbonized alternatives might be implemented, this study has not attempted to analyze the relative economics of decarbonization solutions for the industrial sector.

However, where industrial decarbonization involves substituting renewable fuels (gas, oil, hydrogen) for the current fossil fuels used, the cost of fuels will be higher – potentially much higher, especially for gas fuels – and this may increase manufacturing costs for energy-intensive industries. These higher operating costs may create a competitive disadvantage for firms whose competitors do not comply with similarly ambitious decarbonization goals, unless otherwise mitigated through state- or utility-administered incentive structures. Further, to the extent industry does relocate to regions without similar decarbonization targets, this may simply relocate overall global GHG emissions, rather than reducing them. The Policy section below discusses some ways to address this, and the **Technical Support Document** accompanying this report provides further detail on issues related to the industrial sector.

79 Overall industrial heat needs represent a smaller share in Rhode Island than in the U.S. as a whole.

QUALITATIVE ASSESSMENT AND OTHER FACTORS

In addition to the results of the quantitative assessment of alternative heating decarbonization solutions presented above, a number of other, more qualitative factors need to be considered. Many of these factors were raised by heating sector stakeholders. In some cases, the ideas presented here represent perspectives expressed by some particular stakeholders, but may not be shared by all. Broadly, qualitative factors that impact the attractiveness and feasibility of certain decarbonization solutions in various applications fall into the following categories:

- **Information deficits.** In addition to the unavoidable uncertainty about future developments that may affect the performance and cost of decarbonized heating solutions, there is a significant lack of current information among consumers, installers, and even utilities and policymakers about the available alternatives, how they work when applied at scale, the buildings and geographies where they may be applicable, what they cost and how they perform. This is, in part, because these decarbonized technologies are relatively new and not yet widespread, especially in the United States. Related to this, there is also no "one-stop shop" where stakeholders can go to understand and compare heating alternatives. The providers of various heating solutions tend to be small and, while each may be familiar with the solutions they deliver, few are able to put the alternatives into context and compare among the options. Greater industry collaboration, coupled with strategic partnerships with the utility and state government, may assist in reducing this barrier.
- **Affordability of energy is key.** Energy costs throughout New England have long been higher than in other regions of the country. Keeping energy affordable throughout the transition to a decarbonized economy is imperative for all the state's residents and its businesses. This is particularly true for low- and moderate-income consumers and disadvantaged populations; policies aimed at decarbonizing the heating sector (as well as other sectors) should be designed to protect these populations in particular. One approach that can help with this is to improve the efficiency with which energy is used, and therefore the state's cost-effective energy efficiency programs must remain in place as a way to help reduce energy consumption and manage longer-term customer costs.
- **Acknowledge the needs of vulnerable customers.** Many low-income customers live in lower-quality housing with less effective, less efficient heating systems. Energy costs are already a burden for many of these customers. It will be important to ensure that decarbonization does not add to the burdens of these customers and policies create opportunities for them to participate in the advantages of decarbonization – both as consumers and potentially offering employment on the supply side.
- **Health and safety concerns about natural gas.** Natural gas use presents both real and perceived health and safety risks that can be avoided by electrification. Gas is combustible and creates risks when gas leaks occur indoors. In addition, indoor combustion of gas causes indoor air quality problems (NOx) that lead can lead to detrimental health effects. In this respect, the use of natural gas for cooking can have a greater impact than heating; while heating consumes much more gas than cooking, heating is almost always vented outdoors, but gas cooking is often not vented, or not completely.
- **Consumer preferences.** Some consumers' unwillingness to give up their gas cooking stoves creates a barrier for switching away from gas as a heating fuel. Electric induction cooktops offer

performance comparable to gas (arguably better), but induction is not a well-known technology.

- **Methane leaks mean renewable gas also emits GHGs.** Even renewable gas that is produced entirely without GHG emissions will contribute to GHGs through leaks, due to methane's high global warming potential (about 30 times that of CO_2 over a 100-year timeframe; 85 times over 20 years). Current leak rates are substantial, on the order of 2.7%, which means that the GHG impact of leaked methane can add roughly 30%-85% to the GHG of the CO_2 in the combustion products. While leaks may be reduced, they will not reach zero. This limits the ability of renewable gas to provide fully decarbonized heating.

- **Weatherization effectiveness.** Even if weatherization measures are cost-effective, adoption rates are relatively low. This can likely be attributed at least in part due to non-cost barriers such as the fact that even the kinds of weatherization measures covered by programs like EnergyWise involve "intrusions" into individuals' homes and potentially disruptions to normal use of the home. This is even more the case for deeper retrofits. Energy efficiency policy has evolved to address some of these barriers – for example, by bundling the timing of some energy efficiency measures with the energy audits – but "convenience" likely remains an important barrier to more adoption of cost-effective weatherization measures.

- **Availability of installers.** There is a shortage of available installers for heat pump technologies and stringent licensing requirements may create a barrier to increasing the number of licensed installers. A countervailing concern is that heat pump technology requires a well-trained installer to design and implement a system that will perform well. Effective training programs and industry coordination may help to address these concerns.

- **Electrification depends on decarbonizing electricity production.** Electrifying heat, such as with heat pumps, only results in decarbonization to the extent the electric grid itself is decarbonized. Both perceived and actual delays in decarbonizing the electric system could reduce consumer willingness to switch to electrified solutions. Full decarbonization of the New England electric system to meet traditional and new sources of demand, such as electric vehicles and heat pumps, by 2050 is likely a very significant challenge.[80]

- **High initial costs are a barrier to adoption.** Heat pump technologies, particularly ground source heat pumps, have high initial costs that create a significant barrier to consumer adoption. This is particularly the case for low-income consumers in the absence of policies to mitigate upfront costs. Utilities may be able to help address this to the extent they can finance the initial costs through on-bill financing or rate-basing some of the cost. Mechanisms such as securitization or financing with green bonds may help to further reduce the cost to consumers.

- **Low deployment levels mean non-competitive pricing.** Heat pump technologies, particularly those relevant for heating in Rhode Island (GSHP and cold climate ASHP), are relatively new and costly. This results in consumers facing a relatively immature (and perhaps not very competitive) market

80 For details on the magnitude of this challenge, see The Brattle Group, Achieving 80% GHG Reduction in New England by 2050, September 2019. The report suggests that an acceleration of annual renewable energy deployment of 4-8 times the annual pace currently planned for the decade 2020-2030 will be necessary to accomplish a fully decarbonized system with significant demand from electrified heating and transportation.

of installers, with pricing for heat pumps higher than pricing for installations of more mature technologies such as boilers and furnaces. This is likely particularly true for GSHPs, where the market for geothermal wells is also immature and pricing of drilling such wells potentially higher than it would be in a more fully developed market with higher volumes enabling economies of scale and competition.

- **Local codes and standards.** Rhode Island's building codes and permitting requirements should be reviewed through the lens of wide scale heating sector decarbonization. In particular, the state should work with local communities and the construction industry to ensure heat pump installations can be viably deployed, while reducing construction-related soft-costs to improve affordability. Examples include rules for drilling geothermal wells in dense urban environments, set-back requirements for outside condenser units and different permit requirements across localities.
- **Split incentives.** A large share of the Rhode Island population, in particular more economically disadvantaged populations, do not own their residence. When non-tenant owners make decisions about heating technology, their economic incentives may disfavor high capital costs since they tend to incur those while they tend to pass on fuel and other operating expenses. This in turn may create a barrier to heat pump adoption.

Table 2 is organized according to the various solutions for decarbonized heating technologies, and summarizes some of the less easily quantified attributes that may impact their attractiveness from the perspective of individual consumers or the state, and identifying whether these factors have positive or negative implications for the given technology.

CONCLUSIONS FROM ANALYTIC MODELING AND STAKEHOLDER INTERVIEWS

The analytic modeling efforts and the series of stakeholder interviews and public workshops that were undertaken in this project have raised a number of important issues and conclusions about the transformation of Rhode Island's heating sector. In addition to reinforcing many of the analytical conclusions, stakeholders pointed out further implications that were beyond the scope of the analyses.

Decarbonizing the heating sector in Rhode Island will mostly mean decarbonizing residential and commercial space heating, since these account for the majority of heating needs in the state. And it will occur mostly by retrofitting existing buildings, since the rate of new building construction is quite low; most of the buildings that will exist in Rhode Island by 2050 already exist now.

Energy efficiency improvements to existing buildings will be an important component of decarbonization, since they reduce the amount of heat that must be provided. Heating requirements for an existing building can typically be reduced by roughly 15% at reasonable cost with simple efficiency improvements (weather stripping, air sealing, attic insulation), saving consumers money while reducing emissions. But much greater efficiency improvements tend to be costly and disruptive in existing buildings, and may not be cost-effective. This means that it will still be necessary to deliver significant amounts of heat to these buildings, and that heat must be decarbonized.

Two broad pathways to decarbonize space heating exist – electrifying heating using heat pumps with decarbonized electricity or using decarbonized renewable fuels (gas or liquid fuels) in boilers and furnaces like those in current use with fossil heating fuels. Each of these pathways and the technologies

Approach	Challenge	Comment
ASHP, GSHP	**Market Maturity**	• The market for ASHPs and GSHPs is underdeveloped. Knowledge about quality of installation, competitiveness of bids, etc. are underdeveloped among both consumers and contractors.
GSHP	**Installation Constraints**	• Installing GSHPs requires drilling or digging. There are both physical and potentially permitting constraints that make installing GSHPs challenging in certain instances, such as densely populated neighborhoods and certain geologic formations.
GSHP (some ASHP)	**Upfront Cost**	• GSHPs require significantly higher upfront costs than ASHPs and traditional boiler and furnace systems. This creates adoption barriers due to the unwillingness or inability to afford these higher upfront costs (even if beneficial on average over the life of the equipment).
GSHP, ASHP, Energy Efficiency	**Split Incentives**	• Solutions with high capital cost can be challenging to implement in rental situations; since the tenant benefits from energy savings, the landlord may have little incentive to invest in a more efficient heating system.
Renewable Gas	**Methane Leakage**	• Renewable gas delivered over pipeline infrastructure will result in residual methane leaks. Given the high climate forcing potential of methane, this reduces the ability of renewable gas to provide fully decarbonized heating.
Renewable Gas	**Indoor Air Quality**	• As with natural gas, the use of renewable gas for heating and especially cooking results in indoor combustion, which can lead to poor indoor air quality and health risks.
Renewable Gas	**Effects of gas leaks**	• As with natural gas, indoor leaks of renewable gas present health and safety risks.
Renewable Fuels	**GHG Reductions**	• Largely due to land-use issues, it is difficult or impossible to eliminate all GHG lifecycle emissions of some renewable fuels, such as those derived from fuel crops.
Deep Retrofits	**Implementation and Disruption**	• Deep energy efficiency retrofits (wall insulation, window replacements, etc.) require disruptive interventions, which create additional barriers beyond potential issues of cost-effectiveness.

TABLE 2: QUALITATIVE CHALLENGES AFFECTING DECARBONIZED HEATING ALTERNATIVES

Note: Challenges for one solution represent an advantage for those alternative solutions that do not face a similar challenge.

that implement them has advantages, and each faces challenges.[81]

Renewable fuels have a significant advantage in that they allow for the continued use of existing infrastructure with little or no changes, both for the supply infrastructure and at the customer site. However, there are likely to be only limited quantities available at moderate prices, and if they are used widely for heating (anywhere in the United States since the market for such fuels will be regional or national), the price of renewable fuels is likely to be quite high, especially the price of renewable gas compared to current very affordable natural gas. Renewable gas faces additional challenges. Leaks from the pipelines, the distribution system, and on the customer's premises create substantial GHG emissions, even if the gas itself is entirely decarbonized. Indoor leaks can also create safety risks, and indoor combustion is associated with health risks due to the effect on indoor air quality.

Among the decarbonized electrification solutions, both ground source heat pumps and cold climate air source heat pumps are able to deliver the heating requirements of Rhode Island buildings. Even though air source heat pumps do experience efficiency loss at low outside temperatures, they are able to provide all of a building's heat requirements.[82] This efficiency loss may create some challenges if ASHP is implemented widely, though. The electricity needed to power many ASHPs operating inefficiently in extreme cold would create a significant spike in electric system peak demand, which would raise electricity prices. Ground source heat pumps draw heat from underground where the temperature is nearly constant, so they do not experience this efficiency loss at cold outside temperatures or contribute unduly to peak electric load and prices. They do, however, require a significant additional up-front cost to install the ground loop. For both ASHP and GSHP, installing heat pumps by itself does not decarbonize heat – it is also necessary to decarbonize the electricity supply.

All the alternatives for decarbonized heat are likely to be somewhat more costly than fossil natural gas heat is today, and perhaps very roughly on par with the cost of heating with oil, propane or electric resistance. Based on information available now, and accounting for the substantial uncertainties that affect the future costs of all decarbonized heating solutions – renewable fuel price, the initial cost of installing heat pumps and ground loops, and the price of electricity – it is not clear that any of the decarbonized solutions will be materially more cost effective than the others. This is true both for single-family residential homes, and by extension, for larger multi-family residential and commercial structures.

In fact, the wide diversity of existing buildings and situations suggests that the cost effectiveness and sometimes the feasibility of any approach depends significantly on local and building-specific circumstances. As an example, there may be challenges installing GSHPs in dense urban environments and where the local geology is unsuited for a ground loop. This will lead to different solutions being chosen in different circumstances, and Rhode Island will likely have some broad mix of these decarbonized heating technologies – ASHP, GSHP, renewable gas and renewable oil – in 2050 and beyond. This likelihood of a mix of technologies is reinforced by the fact that relying entirely on any one of them for all heat needs would tend to exacerbate

81 One of the practical challenges will be funding the incentive and consumer education programs necessary to achieve the decarbonization objectives. This report does not address the aggregate cost of such initiatives nor the best means of funding them, but they will be crucial to ensuring delivery of a decarbonized heating future that works for all Rhode Islanders and the state's economy.

82 For an air source heat pump system, it may be economical to use a supplemental heat source (e.g., electric resistance, or maintaining an existing fossil heat system for an interim period) to avoid having to install a very large ASHP to cover peak heat needs.

its own disadvantages: the electric peak impact of ASHP, the high initial cost of GHSP, and the limits on supply for renewable fuels. And the analysis of a mixed solution highlights a particular challenge for the current gas system – that gas volume lost to electrification or efficiency will increase the delivered cost of gas, imposing risks on customers who cannot easily switch away from gas.

This observation about a lack of a dominant technology solution is reinforced by a qualitative observation from stakeholder interviews. On top of the unavoidable uncertainty about future performance and cost, there is a "huge information deficit" and lack of understanding of the decarbonized heating alternatives among consumers, installers, and even policymakers. There are also few providers of decarbonized heat solutions, and no one-stop shop for information that would allow consumers to understand and compare them. This lack of information itself presents a barrier to getting started on the transition.

One important implication that can be drawn from the inability to identify a "preferred decarbonization pathway" is that it is likely premature to cut off options. For example, it is not time to begin dismantling the existing gas infrastructure, since maintaining it, at least for now, keeps options open. By the same token, it may also be best to avoid large, long-lived investments in any particular technology or infrastructure, since there is no guarantee the investment will continue to be useful in the long run.

The next section explores in some depth a number of policy implications of these observations that came from the analytic effort and the stakeholder interviews.

EJW-4

Policy Choices to Transform the Rhode Island Heating Sector

The heating sector is characterized by a number of features that justify policy intervention, including the presence of externalities or public goods, economies of scale, information failures, financing barriers, natural monopolies, etc. Greenhouse gas emissions are a classic externality, though not the only one here – the impact of individual heating technology choice on peak load and electricity price is another. There is also a considerable lack of awareness among consumers, policymakers, and even installers about the current state and likely future development of decarbonized heating technologies. And there are natural economies of scale and scope where coordinated action may facilitate, accelerate, and reduce the cost of heat decarbonization. The widely shared benefits and system interactions that will accompany decarbonization make policy interventions both warranted and necessary. Such interventions can accelerate and facilitate the transformation of the heating sector, and share the disparate individual costs that will likely be borne by individual customers.

The analyses underlying this report conclude that, based on the currently available information, none of the identified decarbonization pathways is clearly better than the others. The most appropriate and most economical decarbonized heating solution remains uncertain, and may depend on a customer's unique circumstances. For example, the long-run cost of renewable fuels is highly uncertain, particularly if they must supply fuel volumes similar to today. Also uncertain is the ability to overcome deployment barriers for ground source heat pumps, and the cost of heat pumps and the price of electricity from a fully decarbonized grid. In addition, the cost and applicability of these solutions to any particular (existing) building will often depend on its unique circumstances. It does seem likely that, on a purely economic basis, decarbonized heat will be more costly than the cheapest fossil solution today (natural gas), though not necessarily when compared to oil or propane.

For these reasons, rather than discrete technology mandates that may prematurely dictate technological and economic outcomes, it is appropriate to develop a set of policy principles to guide policy development, giving flexibility to respond to changing circumstances and information. In the short- to medium-term, policy should remain technology-agnostic about the long-term transformation, while promoting early demonstration and development of a number of promising technologies and program structures to learn and fill the information gap, and taking action to future-proof the heating system by not locking into any particular path. The focus should be on early activities that not only achieve emissions reductions (though that is important), but also facilitate a dramatic acceleration of decarbonization in the future.

POLICY PRINCIPLES

The uncertainty about the best long-run decarbonization approaches, the lack of information and experience, as well as the need to make early progress on the heating transformation suggest several principles for policy development, laid out below in this section.

Ensure progress: Collectively, the chosen set of policies should ensure that material progress is being made on decarbonization. One way to do this is to decarbonize all possible heating pathways, so that whatever path is chosen by individual consumers, the overall heating sector in Rhode Island is making progress toward decarbonization. This could take the form of decarbonizing the electricity that will power heat pumps that are deployed, while simultaneously decarbonizing fossil-based heating fuels for customers who continue to rely on traditional furnaces and boilers. On the electric side, Governor Raimondo's Executive Order requiring 100% renewable electricity by 2030 (EO 20-01) is an important step forward.[83] Rhode Island has also taken an initial step toward decarbonizing traditional fossil heating fuels with a 5% biodiesel blending requirement for heating oil in the state. Extending such a blending requirement to the natural gas system and increasing the share over time, ultimately to 100% for both gas and oil, will ensure ultimate decarbonization, regardless of which pathway is ultimately chosen by customers.

Take advantage of "natural investment opportunities": Heating infrastructure, such as building envelope components, boilers or furnaces, gas distribution pipes, power lines, etc., is very long-lived and is replaced or updated only infrequently. It is generally much less costly (and thus more cost-effective) to change such infrastructure at a time when the existing infrastructure would otherwise be replaced (or is soon to be replaced), serviced, or even just accessed in the normal course of operations. This has two implications. First, it will often be best to time a change to the heating system to coincide with such interventions, since at that point it will involve less incremental cost and less disruption – for instance, by timing the installation of a heat pump with the end of life of a furnace to save costs. Since a typical furnace or boiler life is roughly 25 years, a prompt start means that such natural investment opportunities may occur about once on average for each building by 2050.[84] Similarly, modifications to improve the efficiency of a building envelope are most economical when the building shell is otherwise being modified, particularly for some of the more invasive and costly interventions. Such intervention points may only occur once over the next 30 years. For customers with recently-installed heating systems and/or newly-constructed homes, it may not occur at all. This principle applies at several levels – to the replacement of a furnace or boiler in an individual residential home at the end of its normal life, as well as to the gas and electric distribution infrastructure when components of it are being replaced or upgraded. In either case, it will be less costly to transform the system if decarbonization activities are timed for when a significant investment otherwise must be made in the normal course of business. Taking advantage of natural investment opportunities also implies avoiding lock-in to GHG emitting heating solutions when larger investments are being made.

83 Even with Rhode Island achieving a 100% renewable goal by 2030, the state remains interconnected and dependent upon the regional New England generation and transmission system. Since it will continue to be affected by fossil-fired electricity in this way, efforts to reduce greenhouse gas emissions in the rest of New England will be equally important.

84 This raises another point, which is that it may be quite difficult to transform a building's heating system when the heating system has actually failed. The urgency to restore heat will probably lead to an emergency replacement with a similar furnace or boiler (quick and relatively simple since other parts of the system need not change), which would not allow time to consider, plan and implement a different heating solution. This points to the value of planning such changes systematically and well in advance to occur when the heating system is aging but prior to actual failure.

Extend the planning horizon, and future-proof: Because many heating-related investments will last for decades, investments should be made keeping this in mind. This may be particularly important for the electric transmission and distribution system, where upgrades to the distribution system will likely become necessary over the coming decades to accommodate electric vehicle penetration and potentially more decentralized energy production (such as rooftop solar PV). Since distribution system upgrades likely involve a significant element of "fixed costs" (deploying workers and equipment), the incremental cost may be modest to make larger upgrades than those immediately needed, and would create additional capacity to accommodate longer-term needs, including potential electrification of heating, thus avoiding the need to upgrade capacity multiple times in smaller increments.

Implement no-regrets improvements – but don't stop there: There are likely some changes that can be made that would qualify as "no-regrets" actions in that they will be valuable regardless of future developments in the heating sector. Such policies should be pursued where they can be identified, but policies will likely need to go well beyond such no-regrets actions. The magnitude and speed of the transformation needed means that a broad array of approaches must be implemented in order to make enough progress quickly enough. This will include some that may not be guaranteed to be "successful" in all future states of the world, though even policies that appear unsuccessful often yield valuable information and experience that can advance the ultimate objective. Fortunately, there are many policy actions that do not require large resource expenditures or irreversible commitments, or foreclose major alternative solutions. Many of these involve relatively small investments to learn or disseminate information about the cost and effectiveness of decarbonized heat technologies. Pilot and demonstration projects, or information campaigns directed at the public (consumers), equipment installers and even policymakers can be relatively low-cost ways to expand the information set and enable a faster, smoother transition. Planning is also relatively low-cost and facilitates considering multiple alternatives rather than foreclosing options. This includes developing plans for actions that may never be taken, where the act of planning draws out useful information and identifies what actions would be necessary to implement the plan, well ahead of an actual decision point. The gas and electric utilities may be in a good position to develop high-level plans for how they might implement or facilitate a transformation along any of the pathways, and can identify barriers so they can be addressed before they slow progress.

Learn and share information: Given the limited state of information about decarbonization pathways in the heating sector, there is substantial scope for efforts to promote learning and information sharing. Efforts could take the form of public information campaigns, pilot and demonstration projects (best if well-publicized), etc. Such efforts can accelerate and facilitate decarbonization along several of the potential pathways, in part by helping to generate the public and political support necessary. Much can be learned from projects already done or in process, and systems already available elsewhere. But local pilot and demonstration projects can also be useful for learning about how technologies and approaches may apply in Rhode Island circumstances, and they can also play an important role in publicizing and disseminating information.

Plan for contingencies: In light of the scope and unfamiliarity of the transformation that is necessary, and the uncertainties about the ultimate cost and performance of alternative pathways, an early start to planning the transition is crucial. This does not mean (only) planning what specific actions will be taken, though that is ultimately necessary. It also means developing reasonably well-specified though still high-level contingency plans for a range of potential pathways and possible futures, as a way to identify the opportunities and obstacles that may be encountered and to begin to make progress on addressing them. For example, given there is at least a possibility of heavy reliance on air-source heat pumps, it will be useful to explore how the electricity peak impacts might be handled, and potential ways to mitigate them. Similarly, while it is not yet clear that decarbonization would involve a large decrease in delivered gas volumes, it will nonetheless be useful to understand how this would affect the gas system and develop approaches to address it. Over time as the transformation progresses and more is learned, the contingency plans can be updated, and ultimately some of them will likely be implemented.

Keep options open: Because of the large uncertainties about the cost (and to a lesser extent, the performance) of the various decarbonization pathways, it is not clear now which, if any, will ultimately dominate. In this circumstance, it is important to avoid foreclosing potentially promising decarbonization pathways, and will be equally important to open up potential pathways by using some of the principles noted here to determine how they might be implemented and learn about their benefits and costs. Learning and contingency planning activities can be used to identify and select the right pathway, and will also facilitate its ultimate implementation. As an example, it is almost certainly too soon to commit to abandoning or paring back the gas delivery system, but it will be useful to plan how to optimize it to take advantage of renewable gas where it is most important. This might involve expanding the gas system in industrial zones with few alternatives to burning fuel, while perhaps restricting new residential connections where alternatives are available.

Planning ways to decarbonize both paths (renewable fuels and electric heat pumps) can preserve a diverse set of alternative solutions while clarifying the tradeoffs. In fact, because of the diversity of buildings, geology, infrastructure, etc. in Rhode Island, it is very unlikely that any single decarbonization technology will dominate in all instances. This implies that the ultimate solution will probably include at least some of each approach – building efficiency, ground and air-source heat pumps, renewable fuels. Since the amount of each that must ultimately be implemented will almost certainly be more than currently exists, beginning now to pursue all these pathways simultaneously is likely to be a positive step toward decarbonization, and can be particularly useful where actions are targeted to learning and information sharing opportunities. As more is learned, if one of the technologies begins to look relatively better than the others, implementation efforts can shift toward it, giving it a larger role in the ultimate mix without regretting the early implementation of other approaches.

A POLICY ROAD MAP FOR THE NEXT 10 YEARS

Transforming Rhode Island's heating sector over the next three decades is a major challenge and requires making significant progress not just in the distant future, but also (and perhaps critically) within the coming decade. While it may be tempting to try to identify the single best technological solution or strategy, the analyses conducted for this project and presented above suggest that, at least at present, such a policy approach would be at best premature.

Hence, a policy roadmap for the next ten years must address the lack of clarity about what specific decarbonization approach(es) are most cost effective and hence worthy of support, the reality that both cost and implementability will likely be customer and application specific, and that making real progress and establishing the groundwork for accelerating heating sector decarbonization in the following decades is an urgent task for the coming decade. This comes against a background in which decarbonized heat is, in many cases, not currently economic when compared against the continued use of fossil

Ensure	Increase efficiency and reduce carbon content of all fuels to zero over time – ensures progress no matter which technologies are used
Learn	Data collection, R&D, pilot projects to understand technologies, infrastructure, and customers
Inform	Educate stakeholders – customers, installers, policymakers – about pros and cons of options, system interactions, etc.
Enable	Facilitate deployment with incentives; target natural investment opportunities; align regulations, rules, and codes; expand workforce
Plan	Expand planning horizon; develop long-term, high-level contingency plans now (do not commit yet) and use to guide near-term policy

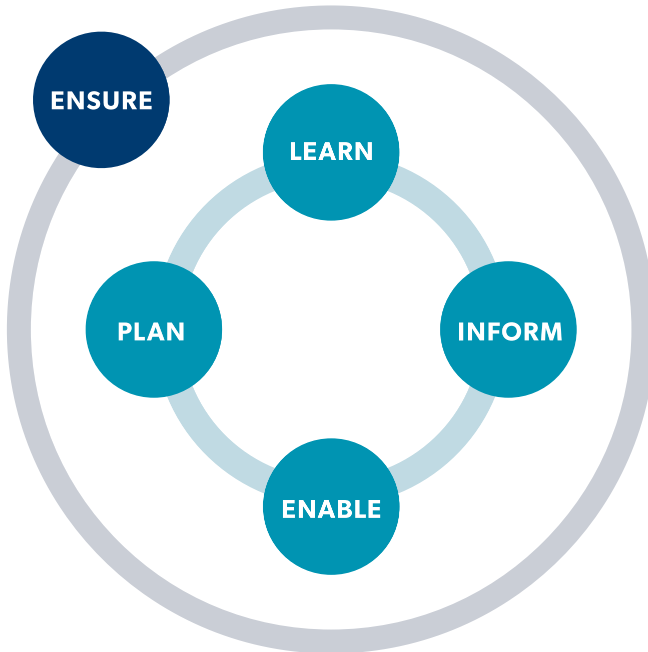


FIGURE 29: THEMES TO GUIDE EARLY POLICY RECOMMENDATIONS

fuels, in particular natural gas – although it may be in time, based on the analysis performed. On the positive side, policy measures that help advance any of the identified approaches are unlikely to cause large regrets in hindsight. With learning and more information becoming available over time, it will be valuable to periodically reevaluate the relative attractiveness of the various solutions and potentially revise policies accordingly.

1. Policy Themes for the Near Term

Against this backdrop, several themes should guide concrete policy actions over the coming decade. They are summarized in Figure 29 and described further below, along with some specific policy suggestions. These themes overlap to an extent; they are not mutually exclusive categories but rather serve as a useful way to organize the policy ideas below, based on their objectives and effects.

a. Ensure

Policy measures that ensure early progress towards zero-carbon heating is made, independent of which heating technology may ultimately be favored, represent the backbone of more specific policies designed to learn, inform, enable and plan. For example, to the extent the carbon content of all available heating "fuels" declines over time to (near) zero, successful decarbonization can be assured. There are many policy approaches to ensuring progress. They include fuel- and technology-neutral GHG reduction policies, maintaining or expanding support for ongoing activities contributing to heating decarbonization, etc. If structured properly, policies that ensure early GHG reductions may also offer longer-term benefits such as learning, informing or expanding delivery capabilities, which can increase their impact. Some of these policies can be relatively easily implemented by Rhode Island alone, while others would likely benefit significantly from regional or even national coordination. Examples of such policies include:

- **Develop policies that guarantee gradual decarbonization of all heating "fuels,"** so that even if fuels continue to be burned, GHG emissions will fall.[85] Policies in this category include, but are not limited to, renewable "fuel" standards or fuel-specific decarbonization mandates, cap-and-trade programs, or a carbon tax construct. Given the size and connectedness of Rhode Island to New England, it is likely that any such policy would benefit significantly from regional coordination. Some existing policies could be expanded or used as a blueprint for developing heating related approaches. For example, the Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade program that covers emissions from most power plants in the electric sector. It could be broadened to include more plants or sectors, just like the cap-and-trade program in place in California was expanded over time to include sources of greenhouse gas emissions other than those in the electricity sector. Similarly, renewable energy standards (RES) can be expanded to the heating sector, requiring decreasing carbon content (or an increasing share of clean or renewable "fuel") across all heating "fuels" or for each fuel separately. Examples include California's low carbon fuel standard (LCFS), which is a program that requires decarbonization across all transportation fuels, or fuel-specific blending requirements, such as the 5% biodiesel blend requirement for heating fuel currently in place in Rhode Island. Finally, Renewable Thermal RPS programs are beginning to be introduced in a number of states, including elsewhere in New England. Renewable Thermal RPS can take many forms, but they generally result in the creation of "renewable energy certificates" (RECs) that are counted against an increasing target. In some states, renewable thermal requirements are bundled with renewable electricity requirements, while in others thermal and electric targets are developed separately.[86]

The Rhode Island electric sector already has both regional and state-level decarbonization targets such as those included in RGGI,[87] the existing Rhode Island Renewable Energy Standard[88] as well as the recently issued executive order to reach 100% renewable electricity supply by 2030.[89] One approach would therefore be to develop similar decarbonization policies for the other heating fuels, either under one program or on a fuel-specific basis, with fuel-specific approaches being likely more easily implemented than policies covering multiple fuels. The biodiesel blending requirement currently in place could be used as a basis for requiring decarbonization of delivered fuels over time. Depending on the desired pace of decarbonization, the biodiesel blend requirement would ramp up over time as illustrated in **Figure 30**.

To achieve full decarbonization by 2050, the renewable content of heating fuels would have to increase by almost 3.5% each year, which would result in a biodiesel blend requirement of about 36.5% by 2030.

It is currently not clear how such a mandate (or a broader Clean Heating Fuel Standard) would affect the price of delivered fuel over time, or how potentially increasing fuel prices would affect the demand for each heating fuel. However, given the uncertainty about how the costs and supply

85 "Fuels" refers to all sources of heating energy including electricity, natural gas, oil, propane and wood.

86 For a description of recent renewable thermal RPS approaches, see Clean Energy States Alliance, Renewable Thermal in State Renewable Portfolio Standards, July 2018

87 For details on RGGI see https://www.rggi.org/program-overview-and-design/elements

88 For details on the Rhode Island RES, see http://www.ripuc.ri.gov/utilityinfo/res.html

89 http://www.governor.ri.gov/documents/orders/ExecOrder_17-06_06112017.pdf

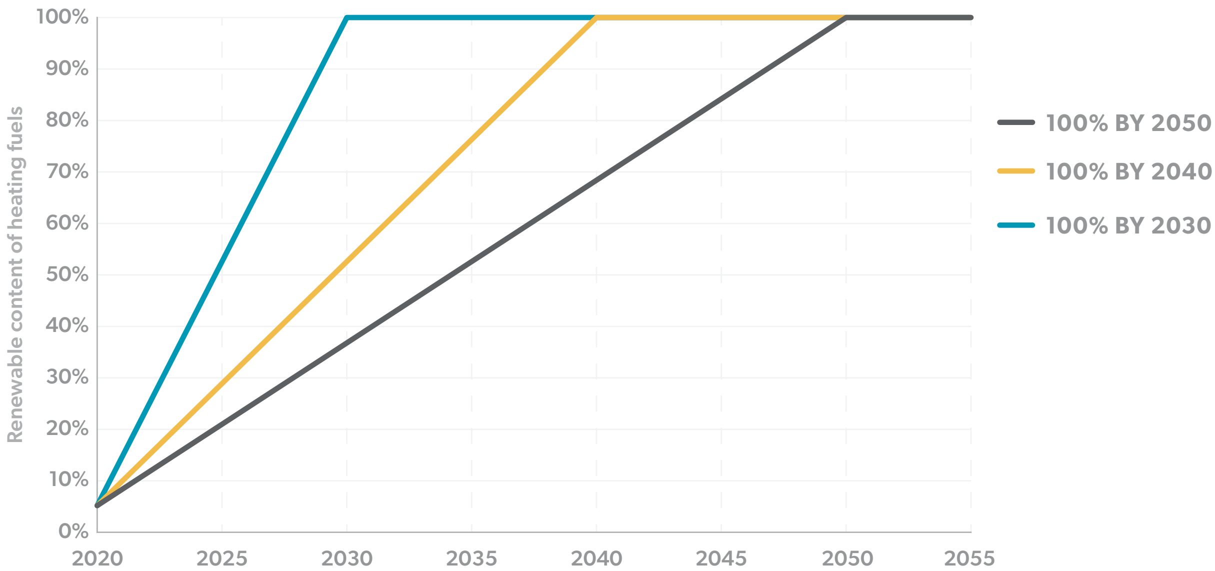


FIGURE 30: ILLUSTRATIVE BIODIESEL BLEND MANDATES RESULTING IN FULL DELIVERED FUEL DECARBONIZATION BY 2030, 2040 OR 2050.

of various decarbonized heating solutions evolve over time, mandating gradual decarbonization of all heating fuels provides precisely the ability needed to let market forces, technological progress and consumer preference determine how the heating sector in Rhode Island decarbonizes over time.

- **Acknowledge the cost impacts of decarbonizing fuels and proactively address them.** Decarbonizing fuels through one of the approaches outlined will create cost impacts for customers of all classes. Consider policies that account for and potentially mitigate these impacts. This may be particularly important for low- and moderate-income customers, as well as industrial customers competing in globalized markets. It is crucial that state policymakers, agencies, and regulators actively collaborate with utilities and consumer advocacy organizations to thoughtfully structure heating investment strategies, and unlock creative opportunities for cost efficiencies. These strategies should be developed within the context of other crucial climate change-related investments, such as accelerating renewable generation and transforming the electric grid to enable higher penetration of clean energy resources.

- **Expand cost-effective energy efficiency improvements** to reduce overall heat needs and support delivery of no-to-low carbon heating solutions. Rhode Island has exhibited national leadership and innovation on energy efficiency and least cost procurement measures. It should maintain and expand these efforts to further develop the workforce, supply chain and markets needed to deliver additional cost-effective building efficiency measures, e.g., by renewing and strengthening the least cost procurement statute.[90] This should include finding additional opportunities for intervention, particularly at "investment moments" where efficiency can be improved at low incremental cost in connection with building improvements or maintenance that is being undertaken for other reasons. Also, building efficiency programs should

90 http://www.energy.ri.gov/policies-programs/ri-energy-laws/least-cost-procurement-2006.php

be fuel-neutral, independent of the heating fuel used, and coordinating the delivery of alternative heating solutions through energy efficiency programs may facilitate their delivery. Recent experience shows that National Grid is essentially on pace to perform efficiency audits of all Rhode Island buildings in the next few decades, though only about one-third of audits lead to weatherization projects.[91] In line with the policy theme of taking advantage of natural investment opportunities, this suggests that increasing the conversion rates of audits into weatherization should be one of the focal areas over the coming decade. Additional cost-effective efficiency measures reduce overall costs to Rhode Islanders – particularly important in the context of decarbonizing the heating sector.

- **Voluntary green tariffs** that allow customers to source a higher share of their energy from renewable sources (perhaps for gas as well as electricity) could engage customer sentiment to accelerate the pace of decarbonization.

Once policies to ensure progress towards heating sector decarbonization no matter what heating fuel or technology is being used are in place, efforts over the coming decade should focus on learning, informing, enabling and planning.

b. Learn

One obvious response to uncertainty is to learn more about the costs, performance and practical feasibility of the decarbonized heating system alternatives. Learning can be supported by policy via theoretical and applied research as well as pilot and demonstration projects. In particular, applied research requires data, and the collection of relevant data – not just about the decarbonized technologies, but also about Rhode Island's buildings and electric and gas utility infrastructure – represents an important precondition for learning. Installing decarbonized heat systems that yield near-term GHG savings will often also create opportunities for learning more about how (or how not) to implement these technologies and the programs that deliver them; similarly, early experience can guide a better understanding of consumer reactions, preferences and information needs. Some specific ideas about policies that could foster learning include:

- **Gather information.** Additional information in a number of areas would be very helpful in developing more targeted policies and incentives and in evaluating progress. Information that should be gathered falls into several categories: more detailed information about the "status" of the current heating sector, such as type, and remaining life of customer-sited equipment; cost and performance information on deployed new technologies such ASHP and GSHP, and issues affecting use of these in individual buildings (need for ductwork, electric upgrades, ground loop, etc.) This information gathering might be implemented by expanding existing efficiency program EM&V work to also include collecting such data. Recognizing that customers likely cannot be required to provide information, policy could tie incentives (or other "carrots") to voluntarily providing relevant information, which can help target or refine policy. For example, information about the remaining life of current heating systems may help target incentives to heating systems when they need to be replaced, rather than replacing systems only upon failure.
- **Research.** Given the uncertainties about various heating decarbonization solutions and the fact

91 In its most recent update, National Grid reports that of the more than 10,000 customers receiving energy audits under the EnergyWise program, 3,700 proceeded with weatherization measures. The Narragansett Electric Company d/b/a National Grid, 2018 Energy Efficiency Year-End Report, May 15, 2019, p.8

that Rhode Island is not alone in attempting to decarbonize heating, policy over the next decade should have a significant research focus. Research and studies to provide more information about the performance, cost, barriers and policy solutions outside of Rhode Island can help focus and improve policy measures in the State. Since Rhode Island is a small state and markets for renewable fuels are likely to be national or international in scope, it may be most effective for the state to partner with other jurisdictions on research (and demonstration) projects. Some examples of research activities include:

- Studies for all of the pathways to identify experience gained elsewhere, understand how that may apply to Rhode Island.
- Studies to identify information gaps, which may then be amenable to studies, pilots or demonstration projects in the state, or in partnership with other states.
- Studies to better understand the potential local, regional and national sources for renewable fuels as well as barriers to their development, including conditions for interconnecting potential renewable gas supplies to the existing gas delivery infrastructure.
- Studies to understand potential geological obstacles to deploying GSHPs or at least to better understand how ground loop costs may differ by area, based on sub-surface conditions and other factors.

- **Understand how the gas distribution system responds to volume loss.** Develop a much better understanding of how the operations and costs of the gas distribution system are likely to respond to heating sector transformation, which may cause both increasing commodity cost (as an increasing share of more costly renewable gas is blended with fossil gas) and decreasing delivered gas volumes (as customers displace some or all of their gas heating needs with alternative heat sources such as heat pumps). Identify opportunities to reduce costs by concentrating volume loss in particular sub-parts of the distribution system and selectively paring back those sub-parts, as opposed to experiencing more or less proportional reductions in volume across the entire system, which would require that the entire system continue to operate with little opportunity to save costs.

- **Understand opportunities and limitations on GSHPs, particularly regarding the ground loop and GeoMicroDistricts.** These may face constraints because of geology and may also be affected by the density of buildings and other infrastructure, perhaps differently for individual ground loops vs GeoMicroDistricts. E.g., can GeoMicroDistricts be used in more dense areas where individual ground loops might be difficult, perhaps by taking advantage of public rights-of-way?
    - Understand the feasibility and cost of GeoMicroDistricts, identifying what types of areas are suited to them in terms of geology, presence of other infrastructure (which might complicate installation) and density of buildings and heating requirements. Understand what extent and participation levels are necessary to make a GeoMicroDistrict viable, e.g., for retrofitting an existing neighborhood with GSHP.

- **Use pilot and demonstration projects to explore options.**
    - For example, use pilot projects to characterize the peak implications of air source heat pumps on the electric system peak in the coldest weather, and options to mitigate, shift or otherwise address them. Potential solutions could include onsite thermal storage systems that shift electricity usage away from peak to

nearby hours, battery backup to store power, or a backup (non-electric) heat system. Pilot and demonstration projects could help to estimate the cost of these measures, and barriers that may exist to implementing them.

- Similarly, use pilots or demonstrations to understand technical issues with blending renewable fuels into the existing fossil fuel streams during a transition period. Identify operational issues that arise with retrofitting equipment to handle very high blends of biodiesel, up to B100.

- **Understand the industrial sector and its heat needs to identify energy-intensive industries that may be vulnerable to the higher cost of decarbonized heat** (e.g., substituting higher-cost renewable fuels for fossil), especially those with competitors in other jurisdictions that may not need to decarbonize.

c. Inform

The current level of knowledge about low- and zero-carbon heating solutions remains low, as was raised several times in stakeholder interviews and public workshops. The transformation of the heating sector will require better information on the part of many stakeholders in the heating system. The individual owners of most or all existing buildings must adopt new heating approaches, and they will be better equipped to take the necessary actions if they have a better understanding of the technologies, and confidence in their advantages (and disadvantages) in terms of cost, comfort, and disruption and in the quality and reliability of installation. It is not only end-use customers who would benefit from better information about the available decarbonized heating alternatives. Even installers and policymakers often do not have good information or shared knowledge bases. Some potential policy options to create better information for all stakeholders include:

- **Use public information campaigns**, such as utility bill inserts, billboards, online or television and radio advertisements, to create familiarity with the alternative technologies and approaches, and to communicate their advantages and disadvantages.

- **Use demonstration projects to inform.** Well-publicized projects, such as public buildings heated with ASHP, GSHP or renewable fuels, can inform customers and make decarbonized heating solutions more familiar and acceptable. Such projects can include not only publicly-owned buildings (Town Hall, library, etc.) but also private buildings frequented by the public (retail stores, restaurants, movie theaters, hotels). Providing consumers the ability to experience decarbonized heating in action can play a major role in overcoming adoption barriers. This also applies to other heating applications that are deemed essential by consumers, such as cooking. Highlighting restaurants that cook with induction stoves might be one opportunity to begin addressing misconceptions about this and similar technologies.

- **Formalize training and certification programs** for professional installers to improve their understanding and make them more willing to undertake installations, and to recommend them to clients where they are warranted. An additional benefit is that this may avoid under-performing installations that could give the technology an unrealistically negative word-of-mouth reputation.

- **Provide information about qualified installers.** Often, consumers are worried about whether or not a given installer is skilled and qualified. Public agencies could provide information about installers that have received proper training and certification and perhaps additional information, such as the number of installations performed and potential consumer feedback (assuming private sector information sources do not provide sufficient information about consumer experiences).

d. Enable

Decarbonization of heating along any of the identified pathways will likely require significant ramping up of a range of activities. The next ten years must set the stage for the deployment of decarbonized heating solutions at large scale by enabling the transformation at many levels. This includes removing barriers and addressing challenges to enable the technologies themselves, the workforces needed to install and implement them, customers' willingness to adopt them, and utility programs, regulatory structures, etc. There is still uncertainty about the long-run cost and performance of many of the potential decarbonization technologies, and it is not yet clear which one (if it is one and not multiple) may ultimately be the best solution in the long run. But that is not reason to wait; it is in fact a reason to push forward, since experience, and not just the passage of time, accelerates the resolution of this uncertainty.

- **Provide buyer incentives for "all."** Depending on the policy approach adopted to ensure decarbonization of all heating "fuels", it is possible that all decarbonized heating solutions remain more expensive than current fossil-fuel based heating. Also, as shown above, payback periods for some solutions may well be longer than the short payback often demanded by consumers, even if they are lower cost in the long run. This is particularly the case for solutions with higher upfront cost, such as heat pumps and especially ground source heat pumps. Finally, learning about the performance and potential cost trajectory of various solutions requires some ramp up of experience across all the decarbonization solutions. For these reasons, incentives that encourage (early) adoption of each of the promising technologies (i.e., all those identified here) are likely needed to jump-start the market for decarbonized heating solutions. These incentives can take many forms, ranging from incentives directed at installers or manufacturers, to purchase price rebates for equipment, on-bill financing or full ratepayer funded installations (via utility ownership) directed at consumers. They could potentially be supported by "green bonds." Ratepayer funding and/or utility ownership are likely most appropriate for solutions that are similar to those traditionally provided by utilities, such as the GeoMicroGrids discussed above (where utility ownership of ground loops would mirror electric distribution wires or natural gas distribution pipes, with end-user equipment such as heat pumps being privately owned). The specific design of incentive programs for various stakeholders is beyond the scope of this study, but, any such undertakings must be planned and implemented carefully, understanding the cost impacts on various consumer groups, and interactions with other initiatives.[92]

- **Improve regulatory structures.** The current gas distribution revenue decoupling law in Rhode Island has the effect of encouraging gas growth and discouraging electrification as an alternative means of heating. Specifically, when the gas utility increases the number of gas distribution customers on its system, the utility receives more revenue per customer in between rate cases. Conversely, when the number of gas distribution customers decreases, the gas utility loses revenue. This ratemaking principle is referred to in the industry as a "revenue per customer" decoupling mechanism. The mechanism was put in place before the impacts of carbon emissions were fully appreciated and policymakers understood that the addition of gas customers would lower the unit cost of gas distribution for the benefit of all gas distribution ratepayers. The regulatory

92 Caution may be particularly important in the near term, given the unpredictable impact of the economic crisis resulting from the COVID-19 pandemic.

framework should be changed to provide the Public Utilities Commission with the authority to develop a framework that de-emphasizes gas growth and encourages decarbonizing solutions in a fuel-neutral way. However, in Rhode Island, the "revenue per customer" mechanism for the gas business is embedded in statute and, thus, prevents the commission from changing this ratemaking mechanism. An amendment to the law would be required to alter it.

- **Enable a regulatory planning process.** A comprehensive and objective planning process could be created by a funding mechanism in gas and electric distribution rates that facilitates a study and statewide planning process that is coordinated and guided by the state energy and regulatory agencies in collaboration with the utility and other stakeholders.
- **Improve rate design**, both existing rates and potential changes, where existing rate structure may give incentives that are inconsistent with decarbonization, or changes may create opportunities to encourage the transition. For example, decoupling rates so that they better reflect fixed and variable cost causation (perhaps adjusted to better reflect GHG costs which do not actually appear in rates, absent a carbon price) may improve incentives. Including the initial gas interconnection cost in the rate base may not be consistent with the potential for scaling the system back in the relatively near future. Similarly, if the transition may cause gas system assets to have a useful life that differs from traditional assumptions, consider adjusting asset lives, both for assessing proposed investments and potentially for recovering the costs of existing assets. Rate design issues may be a useful way to address the peak impact of heat pumps, e.g., with capacity pricing, or time-of-use or real-time pricing. And of course, issues regarding the ability of low-income consumers to have access to low-carbon heat sources can be addressed through rate structures and ratemaking.
- **Explore a combined energy utility.** Consider a joint ratemaking framework and rate design to enable a single combined rate base for both the electric and gas distribution company. Since the primary electric and gas distribution company in Rhode Island provides both services, utility customers could be treated as "energy distribution" customers for purposes of allocating decarbonization costs, rather than segregating "gas distribution" and "electric distribution" customers. This will address the costs of decarbonizing as a single inter-related initiative, which can facilitate a more equitable distribution of costs and protect customers (including low-income customers and renters) who might otherwise be forced to bear high transition costs as a result of their historical energy system.
- **Take advantage of "natural investment opportunities."** As discussed above, any time the building envelope or heating infrastructure is being replaced, serviced, etc., this creates a scarce opportunity to reduce heating requirements or change the heating system. It will help to find ways to identify such situations prospectively so that efficiency improvements and heating decarbonization alternatives can be fully considered, and to take steps to encourage interventions at these points, e.g., through LCP efficiency programs. Also, the addition or replacement of a central air conditioning system in an existing building (which may become more frequent with warming summers) creates a similar

opportunity, and could become an important driver of heat pump adoption.[93] Such intervention points can be used to upgrade electrical systems to accommodate future electrification demands from both heat and transportation. One challenge will be to gather and systematize data that will enable the identification of these natural investment points.

- **Substantially tighten building efficiency standards.** New buildings, and also major building interventions such as rehabs, should meet very high efficiency standards, perhaps net zero energy use. Consider also requiring the use of decarbonized heating systems, perhaps electric heat pumps, in new and renovated buildings, since a missed opportunity is unlikely to arise again soon.

- **Identify and remove barriers.** Enabling will involve identifying and removing important barriers to technology deployment (such as rules, building codes and permit requirements for deploying both ground- and air-source heat pumps, developing clearer rules for biofuels, etc.), efforts to increase the number and skill-level of the work-force that will be needed to deploy rapidly advancing heating technologies, overcoming unwillingness to give up gas for cooking, etc. In part, pushing the early implementation of these technologies will help to identify these barriers.

- **Build supply capacity.** Since heat pump installation is not currently a fully-developed market, Rhode Island will likely need considerably more installers of heat pump systems. To achieve that, it may be necessary to destigmatize the building trades and provide incentives to attract enough talent. Installers will also need high quality training provided to them to properly design and install heat pump systems for the Rhode Island climate.

- **Create separate incentives for heat pumps and for building envelope improvements.** Each helps reduce GHG emissions, independent of the other, and requiring the two to be linked may inhibit adoption.

- **Reserve limited resources for high-value uses.** Renewable fuels likely have an increasing supply curve, with modest quantities available at costs that are not too high, but high demand pushing prices very high. Consider decarbonizing in ways that reserve renewable fuels for high-value uses, like some specialized industrial uses, that do not have a ready substitute, and using other decarbonization approaches where they are available.

- **Understand and consider strategies to mitigate adverse effects.** As the analyses above indicate, decarbonizing heating in Rhode Island may increase the cost of heating for some consumers, particularly those currently using natural gas, and it may similarly increase total energy wallet expenditures for some consumers. The diversity among customers means that cost impacts will likely differ across customer groups and individual customers. Some customers, such as economically disadvantaged customers and industries exposed to competition, may be particularly exposed to any such cost impacts. In this context, it will be important in the near term to identify policies that promote solutions that reduce overall long-term system costs. This will put the state in a better position to consider additional policy alternatives to mitigate remaining impacts on vulnerable customers.

93 In the most recent evaluation of Maine energy efficiency programs including heat pump incentives, 64% of survey respondents listed “Add air conditioning” as the install reason, the third most frequent response after improving energy efficiency and saving on heating costs. See West Hill Energy and Computing, Efficiency Maine Trust Home Energy Savings Program Impact Evaluation, Program Years 2014-2016, August 23, 2019, Appendix G, p.4

e. Plan

Finally, policy could support a change in approaches to planning by various entities including state agencies and regulated entities, notably National Grid. Today's planning activities often have a relatively limited time horizon of ten years or less, and presume that the utility systems will continue to operate much as they have in the past. The focus is on planning for "expected outcomes" – forecasting and planning for the most likely future developments, perhaps considering a few sensitivities. Transforming Rhode Island's heating sector over the next three decades in the presence of the fundamental uncertainties discussed throughout this report likely requires an augmented approach to planning. This should include developing a broader set of high-level contingency plans with longer time horizons – likely with a view at least towards 2050, in addition to current planning horizons – and planning for outcomes and actions that may never materialize, in order to be ready in case they do. Developing such plans does not imply an intention to implement all of them; in fact, some of the plans developed may be inconsistent with others. But developing such plans now will serve several purposes. First, they can guide near-term actions to ensure they are consistent with long-term goals. Second, the process of developing these plans will promote a better understanding of what is likely to be involved with each of the pathways, including the identification of major barriers, allowing solutions to be developed early and avoid delays later. Finally, such plans help provide "shovel-ready" responses if/when some of the contingencies studied should in fact arise. Some concrete examples of this enhanced type of planning include:

- **Use longer-term planning for the electric distribution grid.** Current planning of the distribution grid, including grid modernization plans, tend to be focused on shorter timer horizons such as ten years and based on expected demand as well as its potential evolution. Understanding the implications of electrification of both transportation and heat for demands on the electric transmission and distribution system over the long-run, i.e., through 2050, would allow improving investment decisions. For example, the cost of building out the distribution system as the heating system decarbonizes may be reduced through a better understanding of the additional cost of future-proofing. Rather than expanding system capacity to accommodate expected demand changes over just the coming decade, the planning process should also consider potentially larger capacity increases that could accommodate greater demand growth in the longer term due to high penetration of heat pumps and electric transport. Such planning may also allow targeting first those areas that may be likely to electrify earlier – e.g., non-gas areas where the economics of electrified heat are better.

- **Develop a gas system transition plan.** There is much uncertainty about how usage of the natural gas system will evolve as it delivers an increasing share of lower carbon gas at potentially higher cost, while the cost and availability of other decarbonized heating solutions improve. In this light, the question of the long-run role of the gas distribution infrastructure is one of the most complex and important questions. As the analysis in this report shows, it is too early to draw conclusions about this ultimate role, but developing plans for various eventual roles of the gas system will help the state to prepare for alternative trajectories, as well as identify mechanisms for reducing the impact and cost of a transition away from gas, should it need to be reconfigured, reduced in scope, or even ultimately decommissioned. Such planning should consider possibilities such as paring back some branches while retaining or perhaps even expanding others, e.g., if some industrial customers have no alternatives to gas or for whom renewable gas is substantially more attractive than using decarbonized liquid fuels.

- **Develop a heating transformation implementation plan.** While this report and the Meister Report provide important policy guidance, neither is sufficient to drive the choice and implementation of concrete policy proposals. But these studies could provide a starting point for state agencies to develop an implementation plan with a coherent set of concrete policy proposals that could be implemented directly. Since it is likely that over the coming decade new information will help better understand the attractiveness and barriers to the various heating decarbonization approaches analyzed here, both the heating transformation strategy (this document) and the resulting Heating Transformation Implementation Plan should be revisited periodically. Revisions of the Implementation Plan will be warranted if key metrics such as the ones developed in this report change significantly. For example, while this report suggests policies to scale up any and all of the promising decarbonized heating options are beneficial, from today's perspective, future revisions may conclude that certain approaches become clearly preferred and should be the focus of further policy measures, and others should not.

- **Plan a centralized heat pump conversion effort.** Although it is too early to commit to mass conversion to heat pumps, it will be instructive to begin to develop a plan for how the state and its utilities would organize and implement a widespread decarbonized electrification program for heating (e.g., installation of ASHP and/or GSHP, and perhaps community GeoMicroDistricts) for many buildings across the state. The plan should be informed by smaller programs focused on supporting early adopters and currently cost-effective conversions. The plan could also proactively identify existing heating systems near end-of-life to facilitate the economics, and making the program opt-out rather than opt-in would increase participation. Planning should consider what costs should be recovered and how, and whether the cost recovery mechanisms could be tailored to address equity issues.

- **Expand planning horizons.** State agency and utility planning may require longer horizons than have been used historically. For example, while it might be appropriate to plan component replacements and upgrades just 5-10 years in advance on an "evergreen" system that is expected to last longer than the components being replaced, this is not true when the system must change fundamentally over a shorter horizon. Facing the need to decarbonize over the next few decades, system planning needs to take into account not just the lives of the components that will be replaced, but also the potential life of the system that they are a part of. Policy could therefore encourage or require that any planning processes be enhanced by adding a decarbonized 2050 perspective to all existing planning time horizons.

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Conclusions and Next Steps for Rhode Island

The quantitative and qualitative analyses presented here for heating sector decarbonization solutions lead to the conclusion that, as of today, no dominant heating sector solution fits all situations and is sure to minimize the cost to consumers and businesses. The analysis does suggest that overall, the cost of decarbonizing the heating sector along several possible pathways is likely to be relatively modest on average. The increased heating costs for some customers may be at least partially offset by savings in other energy sectors. However, the cost of decarbonizing heat remains uncertain, both on average and especially as it relates to any particular building, business, or customer.

For these reasons, Rhode Island's heating transformation strategy must ensure that early progress towards decarbonization is made, regardless of which solution or solutions are ultimately adopted. For example, by increased implementation of cost-effective energy efficiency measures and by putting all the energy sources used for heating on a pathway to decarbonization. Beginning with the insights here, Rhode Island can promote this transformation through a range of policy options that focus on learning and informing, to help address inherent uncertainties, and by taking steps to enable and plan for the transformation. These steps will include and are not limited to, creating incentives for customers to decarbonize, while ensuring that vulnerable populations are protected and that policies do not have unintended consequences.

Policymakers should use the coming decade to lay the groundwork and build the infrastructure for increasing the scale and speed of heating sector decarbonization – at least initially pursuing multiple different solutions. As time passes and learning increases, it may become clear that some solutions are better than others, at least for some customer segments, but that will not invalidate the early progress made with other solutions. Indeed, that early progress and the lessons learned from it will lay the foundation for later progress along whatever pathways are ultimately most advantageous.

Although three decades may seem a long time, the scale of the transformation needed in over 400,000 existing residences, corresponding numbers of small and large commercial buildings and industrial facilities, and an entire energy delivery infrastructure is a difficult challenge that will require sustained and careful attention, beginning urgently today.

Glossary

District Heating	A heating solution that provides heat to a number of buildings through a common system, rather than each building providing its own heat. District heating systems traditionally use a centralized boiler and distribute heat through a series of pipes, but the concept has been broadened to include a common ground loop to support GSHP systems in a number of buildings
GeoMicroGrid	A district heating system consisting of a common ground loop that supports GSHP systems in a number of buildings
GHG	Greenhouse Gas
GSHP	Ground Source Heat Pump
GWP	Global warming potential, the heat-trapping potential of a gas, relative to CO_2
MMBtu	Million Btu, a unit of heat energy (approximately equal to 10 therms)
MW	Megawatt, a unit of electric capacity (rate of delivering electric energy), equal to one thousand kW
MWh	Megawatt hour, a unit of electric energy, equal to one megawatt for one hour , equal to one thousand kWh
Power2Fuels (P2Fuel)	Power2Gas or Power2Liquids
Power2Gas (P2G)	Conversion of renewable electricity into renewable gas via electrolysis and methanation
Renewable Gas	Methane made from renewable sources, e.g., landfill gas, anaerobic digesters, gasified biomass, Power2Gas
Renewable Oil	Oil made from renewable sources, e.g., waste cooking oil, oil crops, Power2Liquids
TWh	A unit of electric energy, equal to one million MWh, or one billion kWh

Study Participants and Stakeholder Process

This study involved an extensive stakeholder outreach effort and interactions with a number of key stakeholders to help inform the work. Stakeholder engagement was an integral part of this study and an invaluable source of information and insights. Personnel from the Rhode Island Office of Energy Resources and Division of Public Utilities & Carriers, the state agencies responsible for directing this study, were integral members of the study team. This team benefitted from numerous meetings, calls and communications with National Grid, the electric and gas utility in Rhode Island, throughout the process. The effort also included interviews and meetings with over 20 individual stakeholder organizations, as well as three public workshops (the first two held in Providence, the third conducted virtually as a webinar due to restrictions imposed by the COVID-19 pandemic). These workshops were held to share information, present intermediate results and collect feedback from stakeholders. Throughout the process, stakeholders provided guidance and commentary regarding the key issues that should be addressed, their own perspectives and positions on issues, what information they had and what they lacked. Stakeholders also provided substantial data input and validation, as well as insights to support the analyses.

Acadia Center

Aquidneck Planning Council

Brown University

Cadmus Carbon Pricing Team

Center for Justice

Conservation Law Foundation

Daikin

Efficiency Maine Trust

GEM Plumbing

Green Energy Consumers Alliance

HEET

National Grid

Oil Heat Institute of Rhode Island

Providence Housing Authority

Rhode Island Association of Realtors

Rhode Island Builders Association

Rhode Island Housing

RIMA

Stash Energy

Summit Utilities

Tec-RI

Maine Office of Energy Efficiency

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RIEC4

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Final Draft 12-14-2022

RHODE ISLAND 2022 CLIMATE UPDATE

RI EXECUTIVE CLIMATE CHANGE COORDINATING COUNCIL

AS APPROVED DECEMBER 15, 2022 BY THE RIEC4

Executive Summary

On April 14, 2021, Governor Dan McKee signed into law the *2021 Act on Climate*, which set mandatory, enforceable climate emissions reduction goals culminating in net-zero emissions by 2050. This legislation updated the previous 2014 Resilient Rhode Island Act, positioning the state to boldly address climate change and prepare for a global economy that will be shifting to adapt to clean technology.

The Act on Climate required that the Executive Climate Change Coordinating Council (RIEC4) deliver an update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022 (referred to as the '*2022 Update*').

After a fourteen-month process involving substantial stakeholder engagement, research, and compilation and coordination among the 13 state agencies in the RIEC4, this *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead.[1] We have reviewed the 2016 plan, reflected on the substantial work that has been done in Rhode Island over the past six years, and provided an interim path forward based on work being done across state government.

Looking back, in the 2016 Greenhouse Gas Reduction Plan the authors identified six key policy recommendations for moving forward in Rhode Island:

- Support further evaluation of the costs and benefits of GHG mitigation pathways, including macroeconomic, environmental, and health impact analyses.
- Develop a state-of-the-art 2018-2020 Three-Year Energy Efficiency Procurement Plan, with special focus on expanded access to delivered fuels (oil and propane) heating customers, opportunities to drive toward new demand response strategies, and expanded financing mechanisms to leverage capital toward the achievement of robust savings goals.
- Initiate an effort to escalate clean energy adoption in Rhode Island, elevating our state's position as an emerging leader in renewable energy and building off recent momentum from the nation's first offshore wind farm.
- Explore state and regional mechanisms for promoting clean transportation solutions consistent with addressing the state's largest GHG source sector.
- Craft a framework for addressing utility, rate, and regulatory modernization to position Rhode Island on the cutting-edge of power sector transformation activities and demonstrate our state as a proof-of-concept testbed for integrating clean energy, empowering customers, and improving the resiliency of our electric grid.
- Pursue regional approaches where they promise to enhance progress toward GHG goals, either through existing collaborations such as the Regional Greenhouse Gas Initiative (RGGI) or through newly emerging ones.

Rhode Island has remained focused in these areas and has followed through on all of them. These have been the guiding principles for much of the work done by the RIEC4 over the time since they were published. The specifics of each are outlined in detail in this *2022 Update*. Former RIEC4 Chairperson Janet Coit was clear, however, in her letter submitting that report in 2016 to the Governor and General Assembly that it was just a beginning, and much work and refinement had to follow if Rhode Island was to meet its emissions reduction goals.

[1] The 13 official member agencies of the RIEC4 can be found listed at https://climatechange.ri.gov/state-actions/ri-executive-climate-change-coordinating-council-ec4 In addition, representatives from the RI Department of Labor and Training (RIDLT) have been participating in the meetings (non-voting).

When the legislature passed the Act on Climate and it was signed by Governor McKee in April of 2021, the sense of urgency increased. Goals became enforceable mandates and clear priorities were set for equity, justice, and workforce development. These priorities were to be central to all our work on reducing emissions. Regular reporting, metrics, and dashboards, as well as strategic plans were required to ensure we stayed on track to meet our mandates and clearly communicate status and progress. The *2022 Update* is the first of the plans required by the Act on Climate.

Beginning in September 2021, the RIEC4 initiated a comprehensive public involvement strategy to provide transparency and opportunities for engagement on the development of the *2022 Update.* The RIEC4 met more often – bimonthly versus quarterly – and held meetings throughout the state to allow more Rhode Islanders to participate in critical conversations about climate change. The RIEC4 held over 20 public listening sessions and workshops to gather public input for the *2022 Update*. The RIEC4 has worked closely with Governor McKee to make key appointments to both the RIEC4 Advisory Board and the Science and Technical Advisory Board, has begun work to create a Climate Justice Advisory Group, and OER and DEM have both onboarded additional staff to assist with the state's numerous climate programs, including staff members in both organizations focused on energy and climate justice.

Much has changed in the world, the country, the region, and Rhode Island with respect to attitudes, actions, and science related to climate change since 2016. Key changes since 2016 include new emissions reduction mandates directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

Perhaps most importantly, the *2022 Update* builds the foundation for developing the *2025 Climate Strategy*. The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate, in hope these priorities will be well established by 2025. The *2025 Climate Strategy* will then build out workplans for each sector to meet our mandates and set us on a viable path to reach net-zero emissions by 2050.

The development of the *2022 Update* was an opportunity to reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources. Updates of the modeling will be a significant component of the 2025 Climate Strategy.

The 2021 Act on Climate set forth a mandate to reach 'net-zero emissions by 2050'. However, the law did not define the terms 'net-zero' or 'emissions', leaving open questions of which emissions, how we net those emissions, and on what timeframe the netting occurs. Following public discussions held in three sharing sessions and supplemented by online comments, the *2022 Update* provides definitions and offers several critical caveats related to how our definitions may evolve over the next three decades.

During the dialogs with stakeholders, it became clear that the development of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* was also an opportunity to reconsider and confirm technical aspects of modeling. Current emissions inventory processes, methodologies, and tools were reviewed in detail and, in many cases updated and modernized to use better local data. Two central principles governing how and when we update process, methodologies, and tools specifically related to the 1990 baseline and estimating emissions from the land use, land use change, and forestry (LULUCF) sector. We also include explicit actionable recommendations for additional analysis in support of the development of the *2025 Climate Strategy*, as well as recommendations for improving transparency of how Rhode Island will assess interim compliance with the 2021 Act on Climate.

In terms of progress and where we stand, Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Rhode Island's Greenhouse Gas Emissions come from several sources. The transportation sector is the largest source (39.7%) of greenhouse gas emissions. The thermal sector (residential heating, commercial heating, industry, and natural gas distribution) accounts for 38.8% of emissions. The electricity consumption sector accounts for 18.9% of emissions. Agriculture and waste account for the other 2.6% of emissions. As we electrify more and more of our transportation and heating systems, those emissions will switch to the electricity consumption sector, which will then be eliminated by transition to renewable, zero-emission sources of electricity.

As of July 2022, the state has counted approximately 1,149 MW of clean energy generation capacity. Of Rhode Island's current 1,149 MW total, 430 MW is offshore wind which is mostly under contract for the Revolution Wind facility scheduled to come online in 2026, 527 MW is solar, 148 MW is onshore wind, 35 MW is landfill gas/anaerobic digestion, and 9 MW is small hydroelectric power. Including the 400 MW Revolution Wind project, approximately 85 percent of Rhode Island's current clean energy portfolio is comprised of in-state renewables or projects scheduled for adjacent federal waters.

Key Studies and Legislation Since 2016

Since 2016, the State has conducted several in-depth studies deepening our understanding of decarbonization activities and enabling actions. The *2022 Update* includes a list and summary of over a dozen major studies that either were directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning.

The list of studies in the *2022 Update* is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy. This list does not include state plans in which stakeholders and agencies prioritize and plan investments in state infrastructure nor does this list include retrospective evaluations of programs, though such evaluations are crucial to increasing the impacts of these programs. This list also omits studies conducted by federal agencies and non-governmental organizations that add to our understanding and depth of knowledge.

However, all these studies have advanced the specific knowledge of both decarbonization and resilience in Rhode Island.

Additionally, the Rhode Island General Assembly has debated and passed several bills addressing different aspects of our response to climate change. Probably the most significant legislation was the 2021 Act on Climate, which set statewide, economy-wide climate goals that are both mandatory and enforceable. The Act requires the state reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and reach net-zero emissions by 2050. The Act also requires the development of this update to the *2016 Greenhouse Gas Emissions Reduction Plan* in 2022 and a comprehensive climate strategy by 2025, to be updated every five years thereafter.

Critically, the Act deems addressing the impacts on climate change to be within the powers, duties, and obligations of all state departments, agencies, commissions, councils, and instrumentalities, including quasi-public agencies. The Act gives each agency the authority to promulgate rules and regulations necessary to meet the Act's greenhouse gas emissions reduction mandates.

Also in 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil. The new law that was signed by

Governor McKee requires home heating oil to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025 and 50% in 2030.

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2022, the RI legislature passed a bill, subsequently signed by Governor McKee, to commit the state to 100% renewable energy by 2033.

Offshore wind-powered energy will play a major role in the reduction of greenhouse gasses. In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. In 2022, the legislature authorized procurement of up to an additional 1000 MW of power generated from offshore wind.

Obviously, action is needed to meet the upcoming emissions reduction mandates in the Act on Climate. While the details, modeling, and balancing of these actions across the sectors of our economy will be done as part of the *2025 Climate Strategy*, the following actions are underway and must continue.

Turning our attention to priority actions in Rhode Island's three biggest source sectors – electric, transportation and thermal – this report identifies strategic actions the state needs to advance to meet mandates as outlined in the Act on Climate. Additional priority actions for land use and climate justice are identified further in the report.

Priority Actions for the Electric Sector

Implement the 100% Renewable Energy Standard

During the 2022 legislative session, a 100% Renewable Energy Standard (RES) was passed by the RI General Assembly and signed by Governor McKee. The RES ensures we decarbonize the electric sector with yearly targets. Rhode Island's RES is an existing statutory mechanism by which we can require electricity suppliers to meet an increasing percentage of retail electric sales from renewable energy resources. The RES also sets forth an accounting methodology and process to ensure compliance.

The schedule and yearly targets set forth in the 100% RES law steadily increase over time starting with an additional four percent of retail electricity sales in 2023 and increases until an additional 9.5% of retail electricity sales are needed in years 2032 and 2033.

Modernize the Electric Grid

Our current electric grid is built for one-way flow of electricity from a few large power generators to many end customers. However, decarbonizing our electric grid necessitates a paradigm of two-way power flow between renewable energy systems of all sizes distributed throughout the electric grid to all customers. Safely, reliable, and affordably building out the electric grid will require electric distribution companies to make strategic investments in technologies for a twenty-first century electric grid.

Grid modernization technologies serve the purpose of managing power flow, protecting workers and customers, improving visibility into electricity consumption and grid conditions, building resilience from power outages, and giving customers more choice and control over their electricity use.

Deploy Advanced Meters

Meters that measure electric (and gas) consumption for utility accounts range in capability from simple counting and aggregation of energy use over a billing period to detailed accounting of consumption throughout minutes-long intervals and real-time communication with customers. Most meters in Rhode

Island are more like the former – basic devices that report how much energy a customer uses over the course of a month – and they are reaching the ends of their useful and reliable lives.

Procure Offshore Wind

Offshore wind is a not only a vital renewable energy resource but a significant economic driver of growth and jobs in Rhode Island. As we move to implement the 100% Renewable Energy Standard, offshore wind will play a critical role in affordable meeting both our in-state renewable energy requirements as well as supporting the region.

On July 6, 2022, Governor McKee signed a bill into law adding up to 1,000 MW more megawatts of offshore wind to Rhode Island's clean energy portfolio. Rhode Island Energy, RI's new gas and electric utility as of 2022, then released a request for proposals for up to 1,000MW in the Fall of 2022 (proposals are due in March 2023). It is expected that any new offshore wind projects procured through the RFP would be operational during the first half of the 2030s.

Continue Energy Efficiency Work

Energy efficiency programming in Rhode Island helps residents and businesses adopt and install technologies that allow them to receive the same or better performance from their equipment, buildings, and appliances while using less energy to do so. Rhode Island's energy efficiency programs are offered through the state's utilities and from the Rhode Island Office of Energy Resources. These services can directly lower energy bills for participating consumers, reducing both emissions and energy costs for all consumers, which help support the local economy, and combat climate change. In 2021 Rhode Island's least cost procurement statute was extended to 2029, which ensures these energy efficiency programs for the next seven years.[2]

Complete RGGI Program Review and Implement Suggested Changes

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia to cap and reduce CO2 emissions from the power sector. It represents the first cap-and-invest regional initiative implemented in the United States. Rhode Island has continued to be an active participant in RGGI since 2009. A Third Program Review is currently underway throughout 2021-2023, which will inform RGGI program design for future years.

Priority Actions for the Transportation Sector

There are two ways to reduce emissions in the transportation sector: consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions and take action to incentivize lower-emissions mobility.

Target 10% Penetration of Electric Vehicles by 2030

As of October 2022, Rhode Island has 6,275 *registered* electric vehicles, which is a 1,313% increase in EVs since 2015. If Rhode Island adopted Advanced Clean Cars II, 68% of all new passenger vehicles *sold* in the state would be electric in 2030. By having programs focused on Zero-Emission Vehicles, such as

[2] Least Cost Procurement: http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM

DRIVE EV, an electric vehicle rebate program available to Rhode Island residents and businesses, it will help increase the amount of registered electric vehicles on the road in Rhode Island as well as paving the way for further expansion of EV penetration, post 2030.

As Resources are Available, look to the Transit Master Plan (TMP) and Bicycle Mobility Plan (BMP) as Well-vetted Strategies for Next Steps

RIDOT, RIPTA, and RIDSP have all developed planning work tasks to support mapping, evaluation, and implementation of projects and priority corridors which were recommended in the TMP or BMP respectively. These agencies continue to prioritize projects advancing better connections for both transit and bicycle/pedestrian modes as the state looks to identify funding for the TMP and BMP.

Reduce RIPTA's Carbon Footprint by Decarbonizing Rhode Island's Transit Fleet

The full cost of fleet decarbonization is currently unknown. RIPTA is preparing an Action Plan for Electrification and Service Growth which will provide estimated annual decarbonization infrastructure, vehicle, and energy costs. This plan will be complete in 2023.

Adopt Advanced Clean Trucks Rule

The federal Clean Air Act (CAA) grants the U.S. Environmental Protection Agency (EPA) original jurisdiction for establishing emission standards for new motor vehicles, including heavy-duty trucks.

Under CAA Section 177 (42 USC § 7507), states that choose to adopt vehicle emission standards that are more stringent than the federal standards for new vehicles may adopt standards that are identical to any standards adopted by California.

Rhode Island has previously adopted California's emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California's standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles. Rhode Island should continue to adopt new rules, including California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers, as well as the Advanced Clean Cars II regulation.

Incentivize Electric Mobility

In July 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) and e-Bike rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program. It works towards making EVs more affordable for more Rhode Islanders.

Model Climate Impacts of Transportation Demand

To understand how projects of regional significance in the State Transportation Improvement Program (STIP) contribute to GHG emissions and to assess future policy options and investment strategies towards the reduction of those emissions, Rhode Island Department of Transportation (RIDOT) is working with other state partners to improve the modeling of GHG, establishing performance measures to help reduce emissions and creating a Carbon Reduction Plan per federal guidelines.

Investments in transportation capital projects are prioritized based on many factors, including asset management, readiness, risk levels, available funding, and opportunities for partnership. Due to changes in both state and federal regulations and guidelines, this data-driven process now will include another layer that determines how regionally significant projects impact carbon emissions in the state. The state planning process determines these priorities so that adequate investments are made based on the proper funding sources and uses, and to meet mandates such as performance measures.

Develop 'Complete Streets' State Plan Leveraging Federal Funding

The USDOT defines "Complete Streets" as "Streets that are streets designed and operated to enable safe use and support mobility for all users. Those include people of all ages and abilities, regardless of whether they are travelling as drivers, pedestrians, bicyclists, or public transportation riders. The concept of Complete Streets encompasses many approaches to planning, designing, and operating roadways and rights of way with all users in mind to make the transportation network safer and more efficient. Complete Street policies are set at the state, regional, and local levels and are frequently supported by roadway design guidelines."

In Rhode Island, RIDOT and RIDSP have joined together to maximize the impact of that funding. RIDSP will lead a 2.5-year effort to invest more than $250,000 in combined planning funds into development of a Complete Streets Plan and Design Guidelines. This project has kicked off (fall 2022) with a draft RFP for consultant assistance, which RIDSP expects to complete and issue in spring 2023, in coordination with RIDOT and RIPTA. This project is included in the FY2023 Unified Planning Work Program (UPWP), which is the annual RIDSP program of projects under development.

Priority Actions for the Thermal Sector

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island.

Continue Energy Efficiency Programs and Weatherization

Weatherization of buildings is key to ensuring a successful transition to decarbonized heating and cooling, because it helps to decrease our overall energy demand. While the utilities' efficiency programs support a number of weatherization programs and appliance efficiency standards, these should continue to be expanded

Target 15% Penetration of Energy Efficient Electric Heating by 2030

A conversion of 15% of Rhode Island's buildings from fossil fuel heat to efficient electric heating by 2030 is an aggressive, but attainable and necessary target. While the market for efficient electric heating – including a variety of heat pump technologies – is relatively nascent in Rhode Island, the next several years will be used to build a strong foundation for the market to expand at a quicker pace in the last two decades as we approach 2050. The priority actions below will help us reach this 15% target and plan for further expansion, in tandem with other decarbonized thermal technologies, post 2030.

Efficient Heat Pump Incentives

There are several mechanisms for incentivizing efficient heat pumps that are expected to be used in the coming years. First, the Office of Energy Resources will be launching the High Efficiency Heat Pump Program (HHPP) in 2023, which will combine federal funding from the American Rescue Plan Act (ARPA) with existing incentives provided by Rhode Island Energy's energy efficiency programs. Second, the Inflation Reduction Act, recently passed by the U.S. Congress, will provide a suite of incentives including tax credits and rebate programs for heat pumps and other electric thermal appliances, such as induction stoves. The State will work diligently to ensure that the maximum benefits are easily accessible to Rhode Islanders and that federal incentives for heat pumps compliment State offerings.

Increase Biofuel Blending in Accordance with the 2021 Biofuel Heating Oil Act

The 2021 Biofuel Heating Oil Act requires that, by 2030, all No. 2 distillate heating oil sold in Rhode Island, "shall at a minimum meet the standards for B50 biodiesel blend and/or renewable hydrocarbon diesel." This means that by 2050 all heating oil in the state will contain at least 50% biodiesel, significantly decreasing the carbon intensity of home heating oil.

Continue to Abandon Leak-Prone Gas Pipes and Pursue Non-pipe Alternatives

Public Utilities Commission Docket No. 5210, "National Grid's FY 2023 Gas Infrastructure, Safety and Reliability (ISR) Plan," contains the Leak Prone Pipe Replacement Program which replaces leak-prone gas mains throughout the Rhode Island gas distribution network. Since the program's beginning in 2012, 537 miles of leak-prone pipe have been replaced and an additional 951 miles are expected to be completed by the program's end in 2035. Gas mains that are replaced through this program have an expected lifespan between 50-100 years, locking in gas infrastructure well beyond the target date for an emissions-free state. Therefore, in the coming years, more emphasis should be placed on non-pipes alternatives (NPA). NPA seeks alternative ways of providing thermal service to Rhode Islanders, rather than expanding and enforcing the fossil gas network.

Future of the Gas Distribution System

Just over half of Rhode Islanders are connected to the gas system for heating, cooking, and various other household appliances. Gas is also used for high-heat industrial processes. Pipelines and other gas infrastructure have been, and continue to be, built with decades to centuries-long time horizons.

In August 2022 the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG, "Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate." Commencing in 2023, this docket will serve as an important first step in beginning to plan for the gas system's transition to carbon neutrality.

Begin Developing a Renewable Thermal Standard

Like the recently enacted 100% Renewable Energy Standard, the state should begin to plan for a renewable thermal standard to phase thermal emissions down at intervals that align with the Act on Climate emissions reduction mandates.

Looking Forward to 2025 and Beyond

The Act on Climate required that the RI Executive Climate Change Coordinating Council (RIEC4) deliver this update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022. After a fourteen-month process involving substantial stakeholder engagement, research, and compilation and coordination among the 13 state agencies in the RIEC4, this *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead.

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with RMI and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by Acadia Center utilizing RMI's *Energy Policy Simulator* (EPS). By modeling a short list of key policy scenarios as outlined in the report, it is projected that Rhode Island is not fully on track to meet the Act on Climate's 2030 reduction mandate of 45% by 0.5 $MMTCO_2e$. To put this in perspective, the emissions in

2030 are projected by the EPS to be 7.39 $MMTCO_2e$, as compared to the 1990 baseline of 12.48 $MMTCO_2e$. This is a very simple, preliminary model that verifies Rhode Island is moving in the right direction but is not at the point where we can be confident in our success. More refined modeling and development of specific strategies to increase that confidence will be the crux of the *2025 Climate Strategy.*

On that note, the RIEC4 will immediately turn attention to the *2025 Climate Strategy*, which will include a set of "strategies, programs, and actions to meet economy-wide enforceable mandates for greenhouse gas emissions" due by December 31, 2025. The *2025 Climate Strategy* will be developed via a robust stakeholder process modeled closely on the process used for the *2022 Update* and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The *2025 Climate Strategy* will be a comprehensive working document that will be updated every five years thereafter.

The agencies in the RIEC4 will focus on implementation of the action items outlined above and throughout this report. The RIEC4 will continue to work with the Advisory Board, as well as the Science and Technical Advisory Board (STAB) and Climate Justice working group, to refine policies and develop metrics and the public dashboard called for in the Act. The metrics and dashboard will serve as an educational and communications tool to highlight progress and the status of our efforts.

Discussions of identifying and allocating resources to these efforts will continue. The decarbonization and transition of our economy must be done carefully, and deliberately, to meet the goals set forth in the statutes. This will require both internal and external expertise and support for all the agencies. In the near term, prospects for federal support in many areas looks strong, particularly from the federal Bi-Partisan Infrastructure Law and the Inflation Reduction Act. However, these federal funds will not provide complete support needed for our efforts and state funds will be needed. Effective community and stakeholder engagement will especially require financial and expert support so that the voices of all Rhode Islanders can be heard as we move forward.

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Introduction and Scope

On April 14, 2021, Governor Dan McKee signed into law the 2021 Act on Climate, which set mandatory, enforceable climate emissions reduction goals culminating in net-zero emissions by 2050. This legislation updated the previous 2014 Resilient Rhode Island Act, positioning the state to boldly address climate change and prepare for a global economy that will be shifting to adapt to clean technology.

The Act on Climate required that the Executive Climate Change Coordinating Council (RIEC4) deliver an update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022 (referred to as the '*2022 Update*'). The Act was clear that the *2022 Update* needed to be informed by public comment and stakeholder discussions. This *2022 Update* reflects the work of many people over the past fourteen months and is the first major milestone in implementing the Act on Climate.

Following the completion and submission of this report, our attention will turn to the strategies, actions, and modeling to meet the reduction targets in the law. The RIEC4 will develop a plan to incrementally reduce climate emissions to net-zero by 2050 to be delivered to the Governor and the General Assembly by December 31, 2025 (referred to as the '*2025 Climate Strategy*'). The *2025 Climate Strategy* will be developed via a robust stakeholder process and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The *2025 Climate Strategy* will be a comprehensive working document that will be updated every five years thereafter. This, however, should not be viewed as the only opportunities or requirements for state agencies and offices pertaining to climate action (e.g. regulatory authority, mission, duties, etc. as called for in RIGL §42-6.2-8).

A note on terminology:

- ***2016 Plan*** refers to the *2016 Greenhouse Gas Emissions Reduction Plan* published in December 2016 in response to the 2014 Resilient Rhode Island Act
- ***2022 Update*** refers to the required update to the *2016 Greenhouse Gas Emissions Reduction Plan*, as mandated by the 2021 Act on Climate
- ***2025 Climate Strategy*** refers to the set of "strategies, programs, and actions to meet economy-wide enforceable targets for greenhouse gas emissions" due "no later than December 31, 2025, and every five (5) years thereafter", as mandated by the 2021 Act on Climate

The following scope and objectives of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* were informed by discussions with stakeholders and the public during a November 2021 sharing session, as well as by comments received through the online public comment portal.[3]

The *2022 Update* should:

- *Be responsive to the 2021 Act on Climate*
- *Center equity and be developed using a meaningful public participation process*
- *Leverage lessons learned since 2016*
- *Build a foundation for the* 2025 *Climate Strategy*
- *Reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources*
- *Focus on near-term actions to achieve the 2021 Act on Climate's 2030 mandate*

[3] The RIEC4 utilized an online comment portal called Smart Comment to collect and review comments submitted by interested parties.

First, the *2022 Update* must first and foremost be responsive to the 2021 Act on Climate. We are operating under the premise that the legislative intent and objective of the 2021 Act on Climate mandates is to limit the worst impacts of climate change in alignment with the latest science.[4] We rely on the latest science and recommendations of the Intergovernmental Panel on Climate Change (IPCC).[5]

Second, developing the *2022 Update* should rely on robust and meaningful stakeholder engagement in order to appropriately center equity into the discussion. We welcomed feedback and suggestions from stakeholders throughout the development process, and relied on a combination of workshops, sharing sessions, and one-on-one conversations to strike a helpful balance of providing support, facilitating conversation, and making space to listen and learn.

Third, the *2022 Update* should recognize and leverage lessons learned since 2016 when the previous greenhouse gas emissions reduction plan was published. Key changes since 2016 include new emissions reduction targets directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

Fourth, the *2022 Update* should build a foundation for developing the *2025 Climate Strategy*. These two documents should avoid duplicating each other and instead build on each other so that we place continued pressure on reducing our emissions. The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate. The *2025 Climate Strategy* will then build out workplans for each major sector in order to meet our interim mandates and set us on a viable path to reach net-zero emissions by 2050.

Fifth, the development of the *2022 Update* is a ripe opportunity to reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources. Modeling will be a significant component of the 2025 Climate Strategy.

Finally, the *2022 Update* identifies a clear set of priority near-term action items that will keep Rhode Island on a compelling path to reach the 2021 Act on Climate's 2030 mandate of 45% emissions reduction below our 1990 baseline. Further accountability, roles, and responsibility are included for each priority action wherever possible.

Based on these objectives, we developed the following scope of the *2022 Update*, which informed both our workplan for developing the *2022 Update* and the outline reflected in this document.

Scope of the *2022 Update:*

- Technical updates:
  - Update greenhouse gas emissions reduction targets to comply with the 2021 Act on Climate, and define the goal of reaching 'net zero emissions by 2050'
  - Review modeling to ensure the 1990 baseline is sound, data are defensible, and modeling assumptions are reasonable

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[4] See for example RIGL §42-6.2-3.9, which states state agencies shall "Develop plans, policies, and solutions based on the latest science to ensure the state continues to have a vibrant coastal economy, including protection of critical infrastructure, and a vibrant and resilient food system that can provide affordable access to healthy food for all Rhode Islanders" (emphasis added).

[5] Intergovernmental Panel on Climate Change

- Update pathways, policy, and implementation strategies:
  - Restructure pathways and policies from *2016 Plan* to coordinate with emissions sectors
  - Provide updates on progress for each policy and implementation strategy recommended in the *2016 Plan*
  - Add policy and implementation strategies recommended by more recent studies
  - Refine policy and implementation strategies based on lessons learned
  - Update policy and implementation strategies to identify priority actions to meet the 2030 mandate, clarify roles, and identify mechanisms for accountability
  - Consider new and forthcoming funding opportunities
- Review and update the entire *2016 Plan* with equity appropriately centered and integrated throughout
- Identify key stakeholders to engage (and engage them!)
- Design a climate dashboard that tracks progress on community-prioritized outcomes using clearly defined, transparent, and meaningful metrics
- Identify and address the prerequisite needs of the *2025 Climate Strategy* and preview the work ahead

Components of the *2016 Plan* that do not need to be updated include the model itself; the guiding objectives to build on state success, enable markets and communities, and leverage regional collaboration; and the process of RIDEM's triennial greenhouse gas reporting.

Defining Net-Zero Emissions by 2050

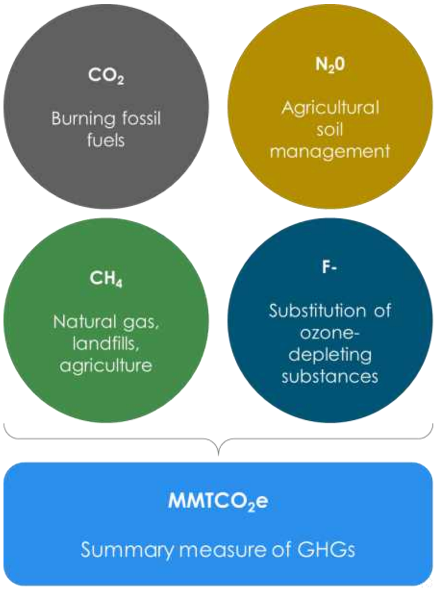
The 2021 Act on Climate sets forth a mandate to reach 'net-zero emissions by 2050' (RIGL 46-6.2). However, the law does not define the terms 'net-zero' or 'emissions', and therefore leaves open questions of which emissions, how we net those emissions, and on what timeframe the netting occurs. Following public discussions held in three sharing sessions and supplemented by online comments, we propose the following definitions and offer several critical caveats related to how our definitions may evolve over the next three decades.

> 'Emissions' refer collectively to the set of greenhouse gases that contribute to climate change. Based on current science, greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. The greenhouse gases included in our definition of emissions may evolve over time if climate science uncovers additional gases contributing to climate change.
>
> 'Net-Zero' refers to the requirement that the summary measure of greenhouse gas emissions emitted over the course of a calendar year less the summary measure of greenhouse gas emissions absorbed or otherwise broken down over the course of a calendar year equals zero. All emissions can be summarized in a measure such as million metric tons carbon dioxide equivalent ($MMTCO_2e$) using global warming potential factors which adhere to international standards, including those of the IPCC[6] and UNFCCC[7], and are embedded within the US EPA's[8] greenhouse gas emissions inventory tools.

Which emissions?

Greenhouse gases are molecules that cause and exacerbate climate change. The IPCC and US EPA identify four types of greenhouse gases[9]:

[6] Intergovernmental Panel on Climate Change
[7] United Nations Framework Convention on Climate Change
[8] United States Environmental Protection Agency
[9] "Greenhouse gases (GHGs) - Gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of radiation emitted by the Earth's surface, by the atmosphere itself, and by clouds. This property causes the greenhouse effect. Water vapour (H2O), carbon dioxide (CO2), nitrous oxide (N2O), methane (CH4) and ozone (O3) are the primary GHGs in the Earth's atmosphere. Human-made GHGs include sulphur hexafluoride (SF6), hydrofluorocarbons (HFCs), chlorofluorocarbons (CFCs) and perfluorocarbons (PFCs); several of these are also O3-depleting (and are regulated under the Montreal Protocol). See also Well-mixed greenhouse gas" [IPCC Glossary] Note that IPCC, US EPA, and Rhode Island do not count water vapor or ozone in tracked emissions.



Carbon dioxide (CO2) is the most prevalent greenhouse gas. Its primary source is from the combustion of fossil fuels.

Nitrous Oxide (N2O) is a type of greenhouse gas that is emitted in part from certain agricultural soil management practices.

Methane (CH4) is released into the atmosphere from natural gas leakage, from landfills, and from some agriculture.

Fluorinated gases are a set of greenhouse gases containing hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3). While these gases are less common, they have a more substantial impact on climate change. These gases primarily stem from the substitution of ozone-depleting substances.

One legislative objective of the 2021 Act on Climate is to limit the worst impacts of climate change in alignment with the latest science.[10] We rely on the latest science and recommendations of the IPCC. Since all four types of greenhouse gases are recognized by the IPCC as contributors to climate change, all four must be included in our accounting of emissions generally and in our emissions reduction strategies specifically. If additional greenhouse gases are identified, then those greenhouse gases should also be accounted for.

> 'Emissions' refer collectively to the set of greenhouse gases that contribute to climate change. Based on current science, greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. The greenhouse gases included in our definition of emissions may evolve over time if climate science uncovers additional gases contributing to climate change.

The IPCC regularly re-evaluates the relative contributions of these greenhouse gases to climate change. One key parameter used to describe these relative impacts is a greenhouse gas's 'global warming potential' (GWP). The GWP allows for comparisons of the global warming impact of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2). All global warming potentials are relative to the impact of carbon dioxide, whose GWP is equal to one (GWP = 1). The greater the GWP, the more a given gas warms the Earth compared to CO_2 over that time period. Other greenhouse gases, which have relatively more impact on causing climate change on a molecule-by-molecule basis, have global warming potentials greater than one.

Global warming potentials depend on both the impact of each molecule of the greenhouse gas and how long each molecule stays in the atmosphere. Greenhouse gases that tend to stay in the atmosphere longer have a longer timeframe over which they can cause climate change; on the other hand, molecules that are broken down or absorbed quickly have only a short time over which they can contribute to climate

[10] RIGL §42-6.2-3.9 states state agencies shall "Develop plans, policies, and solutions based on the latest science to ensure the state continues to have a vibrant coastal economy, including protection of critical infrastructure, and a vibrant and resilient food system that can provide affordable access to healthy food for all Rhode Islanders" (emphasis added).

change. Global warming potentials are continually studied by the IPCC and are subject to change over time depending on the most recent analyses.

In practice, we propose to use the global warming potentials embedded in the US EPA's greenhouse gas emissions inventory tools, which adhere to international standards, including the IPCC and UNFCCC. We additionally propose to include a qualitative or sensitivity analysis to describe how our current emissions levels may differentially contribute to climate change if global warming potentials are modified. For example, while our current inventory uses a 100-year timeframe for the global warming potential of methane (because this is the parameter embedded in the US EPA greenhouse gas inventory tool), we will also describe how our inventory might look different if we were to use a 20-year timeframe instead. A qualitative description may be included more frequently than an administratively intensive quantitative sensitivity analysis.

All emissions will be summarized in a metric called million metric tons carbon dioxide equivalent (MMTCO_2e). This metric accounts for both the amount of each greenhouse gas in our atmosphere *and* its relative impact on climate change. This is a common metric used across the climate science sector to summarize greenhouse gases.

Anthropogenic versus biogenic emissions sources

> *Biogenic emissions are emissions that come from natural sources.[11] In contrast, anthropogenic emissions are emissions that come from human activities.[12] Both types of emissions contribute to climate change, and both are accounted for in some manner by the US EPA's greenhouse gas inventory tools. However, our greenhouse gas inventory and emissions reduction strategies tend to focus more on anthropogenic emissions because these are the emissions within our control. We propose to include in our greenhouse gas inventory and definition of emissions whatever emissions sources – anthropogenic and/or biogenic – are recommended by the US EPA in alignment with IPCC guidance.*

There are a variety of methods that can be used to estimate the greenhouse gas emissions from the electric sector. Our current accounting method for the electric sector is consumption-based, rather than generation-based.[13] This means that we calculate emissions based on electricity used within Rhode Island, regardless of where the generation sources are located that provide the electricity.

The consumption-based approach reflects significant historical and ongoing change in the mix of fuels used to generate electricity in New England. When we consider consumption-based versus generation-based inventories, we have to consider how we can ensure that all emissions are accounted for by some state. Consider, for example, Rhode Island and Maine. Rhode Island's consumption-based inventory only accounts for emissions from an in-state fossil-based power plant if its output electricity is consumed in state. However, let's say Maine only has a production-based inventory but uses some of the electricity from the Rhode Island power plant. In this fictional example, the emissions produced in Rhode Island and

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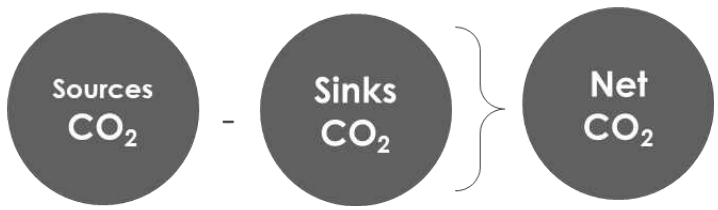
[11] US EPA

[12] IPCC Glossary

[13] In May 2016, the EC4 voted to officially adopt a consumption-based methodology; this memo summarizes those considerations.

consumed in Maine would incorrectly not be accounted for in either state's greenhouse gas emissions inventory. This would lead to too little climate mitigation action.

Therefore, it is critical that we work with neighboring states and states in our region to understand the flow of emissions and ensure emissions are accounted for. This comprehensive accounting also requires consistency in how inventorying is done across state borders. In the absence of consistent methodology, we will need to caveat our greenhouse gas inventory with an additional description of which emissions may not be included.



How do we 'net' these emissions?

Netting is the process of accounting for both sources of emissions and 'sinks' that cause emissions to be absorbed, broken down, or otherwise rendered incapable of contributing to climate change. For example, tree growth is considered a carbon sink because trees absorb carbon from the atmosphere. There are two methods by which we can net emissions. Rhode Island's current greenhouse gas inventory first summarizes all greenhouse gas emissions sources as $MMTCO_2e$ and then subtracts all greenhouse gas emissions sinks as $MMTCO_2e$.[14] An alternative method is to require that each specific greenhouse gas reaches net zero. For example, the total methane emitted by all sources minus the total methane absorbed by all sinks is required to equal zero in 2050, as is required for each type of greenhouse gas.

Given the legislative objective of the 2021 Act on Climate to align Rhode Island's greenhouse gas emissions with the latest science and recommendations to limit global warming and resulting climate change impacts, we propose continuing our current method of netting emissions because the summary measure of $MMTCO_2e$ already encapsulates the total impact of emissions on climate change. In other words, netting each type of greenhouse gas provides no incremental aid in reaching our objective to limit climate change impacts, and may actually be more difficult to achieve.

> 'Net-Zero' refers to the requirement that the summary measure of greenhouse gas emissions emitted over the course of a calendar year less the summary measure of greenhouse gas emissions absorbed or otherwise broken down over the course of a calendar year equal zero. All emissions can be summarized in a measure such as million metric tons carbon dioxide equivalent ($MMTCO_2e$) using global warming potential factors which adhere to international standards, including the IPCC and UNFCCC, and are embedded within the US EPA's greenhouse gas emissions inventory tools.

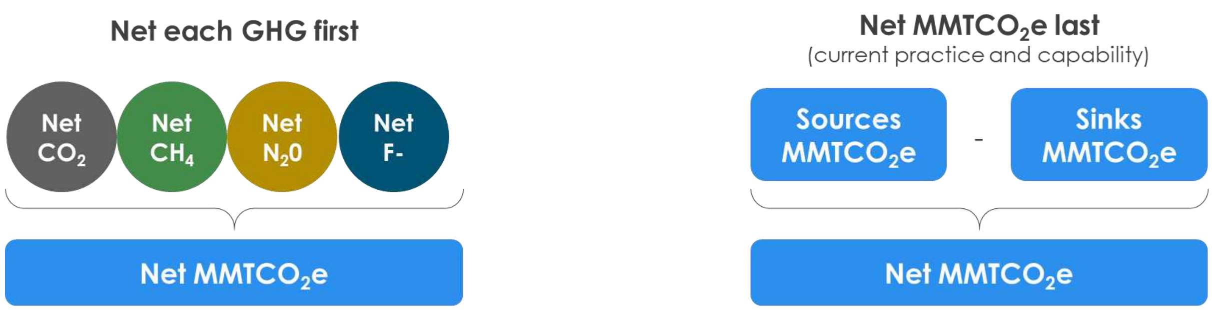
Rhode Island's current greenhouse gas emissions inventory methodology was updated for the 2019 inventory to account for emissions sinks. While the US EPA's greenhouse gas inventory tools do estimate emissions reductions from land use, land use change, and forestry (abbreviated LULUCF), these tools have known reliability issues and therefore are not included in previous years inventories. Rhode Island is

[14] We refer interested readers to the most recent Greenhouse Gas Emissions Inventory (2019) for more information about the updated methodology for accounting for LULUCF. https://dem.ri.gov/environmental-protection-bureau/air-resources/greenhouse-gas-emissions-inventory

moving ahead with utilizing state specific data to account for emissions reductions from LULUCF for 2019 and beyond.

- As we progress toward 2050, we will continue to refine methods of accounting for emissions reductions due to land use, land use change, and forestry.

If future policy objectives arise, such that reaching net-zero for a particular type of greenhouse gas is a solution, then we should revisit our method of netting emissions. We may also consider estimating net emissions for each type of greenhouse gas if our capability evolves such that doing so is not too burdensome; doing so may provide additional insight about the efficacy of our emissions reduction strategies.



Another consideration is whether to net emissions economy-wide or require each sector within the economy reach net-zero emissions. Similar to the argument for netting $MMTCO_2e$ rather than each type of greenhouse gas, netting emissions economy-wide achieves the legislative objective of limiting the impacts of climate change; netting by sector provides no incremental benefit. However, estimating emissions by sector may provide insight into the efficacy of our greenhouse gas emissions reduction strategies if data and tools are available to do so.

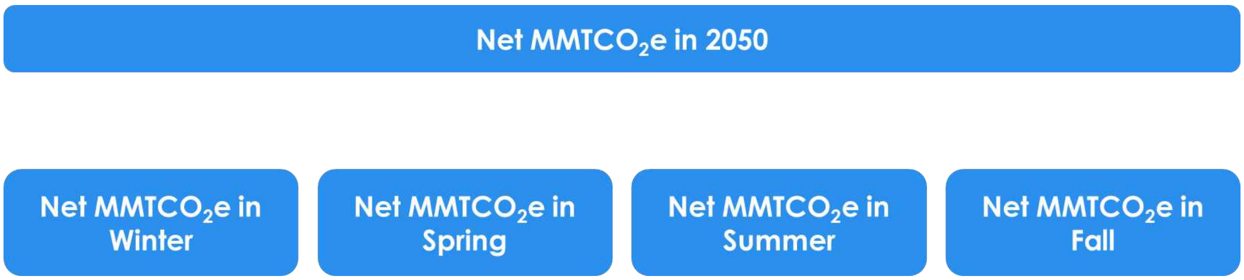
Stakeholders raised two critical concerns about the net-zero emissions mandate. First, stakeholders feared that netting emissions may alleviate a sense of urgency to reduce emissions sources; folks may rely too heavily on as-yet-developed future technology to remove greenhouse gases from the atmosphere. Second, stakeholders emphasized that emissions in our atmosphere will contribute to climate change regardless of the accounting practices we use in our emissions inventory; therefore, we must prioritize actions to reduce emissions rather than dwelling on how to inventory them.

Both concerns are valid and must be addressed. We propose three immediate responses related to maintaining a sense of urgency, limiting our reliance on not-yet-developed technologies, and recognizing the shortfalls of accounting.

Regarding urgency: while this *2022 Update* defines our 2050 emissions reduction mandate, we also include priority actions needed to reach our interim 2030 emissions reduction target. Balancing the emphasis of short-term action with long-term understanding will help with identifying priorities now and developing the *2025 Climate Strategy* over the coming few years.

Regarding future technologies: the priority actions identified within this plan are all related to reducing sources of anthropogenic greenhouse gas emissions and we plan to continue to stress a 'mitigate first – net as a last resort' principle in the *2025 Climate Strategy* and subsequent updates.

Regarding accounting: our greenhouse gas emissions inventories allow us to track progress so that we can adjust course if our strategies are not working as needed. We propose to update our greenhouse gas emissions inventory alongside metrics within our climate dashboard with the objective of continual self-evaluation and improvement. We also will rely on climate experts at the IPCC, US EPA, and at Rhode Island's institutes of higher education to provide technical guidance that underlies our development of strategic policies.



Over what timeframe should we net emissions?

The process of netting emissions sums up the net of all emissions remaining in the atmosphere over a particular timeframe. Current practice is the net emissions over an annual timeframe, in which case the net of all emissions released into the atmosphere between January 1 and December 31, 2050 is required to equal zero. On the other hand, we could require net emissions to equal zero for each season, each month, each day, or even each hour.

There are tradeoffs to a longer timeframe versus a shorter timeframe. A longer timeframe – netting emissions on an annual basis – may be the most appropriate for a complex and volatile system. While more frequent netting – netting emissions sub-annually – may provide insights about seasonal emissions patterns and related emissions reduction strategies, natural randomness and volatility in our behaviors, our economy, and our environment may lead to spurious results and false insights. However, there may be some particular sectors or industries for which sub-annual netting might be appropriate. For example, industries with a defined 'season' (for example, heating) or with relatively insensitive emissions profiles (for example, some manufacturing) might benefit from more frequent netting to obtain more real-time feedback on emissions reduction strategies.

Two additional key considerations are our capabilities and the administrative burden of inventorying greenhouse gas emissions. First and foremost, our capabilities are dependent on capabilities built into existing inventory tools. At this time, we do not have the capability to track emissions on a daily or hourly basis. As tools evolve to include additional flexibility, then our capabilities may evolve as well. Given these capabilities, we want to strike the right balance between getting feedback on our strategies with actually doing the work called for by our strategies; and, importantly, we want to make sure the administrative work we do to measure emissions provides incremental and actionable insights. We propose continuing annual netting at this time, but reassessing capabilities, resources, and benefits within the *2025 Climate Strategy* and each subsequent iteration.

Exogenous limitations

Rhode Island should continue to align with best practices for greenhouse gas inventorying. We do so by leveraging inventory tools developed and maintained by the US EPA, and we rely on the US EPA to update these tools to be consistent with the recommendations of the IPCC.[15] We do not envision Rhode Island developing its own tools, but we will strive to improve methods using the most specific data available for Rhode Island as well as the most recent science and coordinate accounting methodologies with the federal government and neighboring states. We can advocate for the US EPA to develop and enhance these key capabilities in future evolutions of their greenhouse gas inventory tools. Furthermore, our Triennial Greenhouse Gas Emissions Inventory provides insights beyond a single point estimate of greenhouse gases by including a discussion of how this point estimate may be sensitive to certain assumptions and therefore imprecise or biased.

Non-quantitative metrics and lived experience

While our climate mandates entail specific greenhouse gas emissions reductions, the 2021 Act on Climate also discusses the need for strategies regarding climate justice, community resilience, and improving public health. These objectives cannot be represented by a single value of $MMTCO_2e$, so we cannot lose sight of the importance of non-quantitative metrics and lived experience. While this chapter discusses technical accounting methodology for estimating our greenhouse gas emissions, we should also continue to provide opportunities to lift up voices from communities across Rhode Island to share their experiences and trust their expertise on priority actions and success (or failure) of our climate strategies.

Greenhouse Gas Emissions Inventory Process, Methodology, and Tools

Stakeholders suggested the development of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* is a ripe opportunity to reconsider and confirm technical aspects of modeling. The objective of this chapter is to describe current emissions inventory processes, methodologies, and tools in order to highlight changes since 2016 and understand the status quo. Much of this content is adapted from the 2019 Rhode Island Greenhouse Gas Emissions Inventory. We refer interested readers to that report for more detail. [16]

We then describe two central principles governing how and when we update process, methodologies, and tools specifically related to the 1990 baseline and estimating emissions from the land use, land use change, and forestry (LULUCF) sector. We also include explicit actionable recommendations for additional analysis in support of the development of the *2025 Climate Strategy*, as well as recommendations for improving transparency of how Rhode Island will assess interim compliance with the 2021 Act on Climate.

Methodologies

The Rhode Island Department of Environmental Management (RIDEM) is the state agency responsible for estimating Rhode Island's greenhouse gas emissions. RIDEM's Office of Air Resources estimates emissions on a calendar-year basis. For example, the 2016 emissions inventory estimates emissions resulting from activities that occurred between January 1, 2016 through December 31, 2016, inclusive of the end dates. For all inventories, there is a three-year lag between the year of emissions and the year of the inventory. For example, Rhode Island's 2016 emissions inventory was estimated in 2019. Similarly,

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[15] Specifically, Rhode Island uses the US EPA SIT, the US EPA MOVES, and a method developed in-house based on methodology developed by Massachusetts and Connecticut to estimate emissions from the electric sector. We refer interested readers to the most recent Rhode Island Greenhouse Gas Emissions Inventory for additional technical detail.

[16] Available online at https://dem.ri.gov/environmental-protection-bureau/air-resources/greenhouse-gas-emissions-inventory

Rhode Island's 2019 emissions inventory was released in December 2022. Unless otherwise noted, the emissions inventory year (e.g., '2016 emissions inventory') corresponds to the year in which the emissions resulted, not the year in which estimation occurred. This lag time is caused by reliance on multiple federal and state agencies' dataset releases, and the time required to collect data and modify emissions inventory tools. Rhode Island must endure this lag time to access US Environmental Protection Agency's (EPA) emissions inventory tools, which are necessary to complete Rhode Island's emissions inventory.

- Rhode Island should coordinate with other states to request the US EPA shorten the lag time from three years to one year or less.

Like many other states that regularly preform economy-wide greenhouse gas emissions inventories, Rhode Island relies heavily on the US EPA's State Inventory Tool (SIT). The tool is an interactive top-down spreadsheet designed to help states develop GHG emissions inventories. The SIT consists of 11 modules which calculate sector-by-sector greenhouse gas emissions based on numerous state-level data sets, including energy-related data provided by the US Energy Information Administration (EIA). When state level data are likely to be more robust than the tool's default data, the US EPA recommends that states employ their own data.

The SIT estimates GHG emissions by applying pollutant-specific emission factors to Rhode Island activity data. The US EPA updates the SIT annually with the latest activity data. If needed, any updates to emission factors and/or parameters like global warming potentials are made as well. Greenhouse gas emissions are converted to a summary unit of measure called million metric tons of carbon dioxide equivalent ($MMTCO_2e$) based on their global warming potentials that allows for better comparison of the impact of different greenhouse gases. These conversions are completed within the SIT.

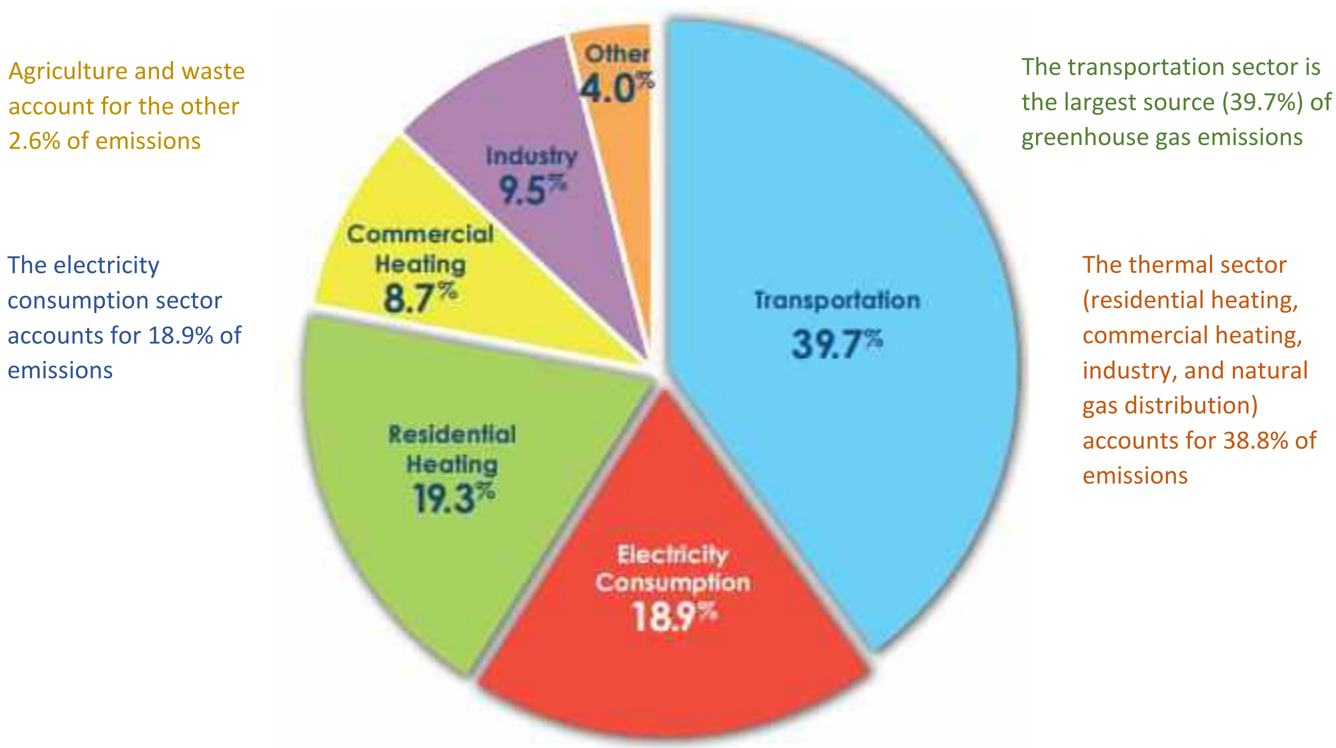
RIDEM releases annual greenhouse gas emissions inventories. Every three years, RIDEM publishes a "triennial summary" that coincides with the releases of the US EPA's triennial National Emissions Inventory.[17] Each National Emissions Inventory details emissions of criteria air pollutants, criteria precursors, and hazardous air pollutants. Triennial greenhouse gas emissions summaries provide a greater level of detail than annual emissions inventories. Table X below displays the history of default versus non-default model runs. All inventories since 2013 were non-default runs and RIDEM anticipates using non-default runs for all future emissions inventories. In these years, state-specific data was utilized to obtain the most robust emissions estimates. Inventory years 2011 and 2012 were default runs for which emissions were estimated using primarily default data in the SIT. This default data relies on top-down estimates rather than bottom-up primary data collection. Non-default model runs are considered more precise. Consistent methodologies – even with differently sourced data –still allows for comparisons of emissions estimates from year to year. However, caution should be applied when comparing emissions estimates year-over-year when we expect the results to be biased differently when using default versus non-default data. See the callout box on *The Role of Models* below for additional explanation.

[17] As described in the *2016 Greenhouse Gas Emissions Reduction Plan*, Monitoring, Page 26.

Table X. Model Run Types by Emissions Inventory Year.

Rhode Island Greenhouse Gas Emissions Inventory											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Triennial Summary Released	No	No	No	No	No	No	No	Yes	No	No	Yes
Model Run Type	Non-Default	Non-Default	Default	Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default

Some categories of emissions require other tools and methods instead of or in addition to the SIT. All of RIDEM's tools provide emissions estimates in $MMTCO_2e$ for each of the nine emissions categories: transportation, electricity, residential heating, commercial heating, industry, waste, natural gas distribution, agriculture, and land use, land use change, & forestry. We summarize these emissions estimated for 2019 below; these sectors – transportation, electricity, and thermal[18] – correspond to the following chapters that identify priority actions to reduce emissions.



Source: RIDEM 2019 Greenhouse Gas Emissions Inventory. Please note that data are consistent, but in this document the Thermal Sector includes the following distinct sectors: residential heating, commercial heating, industry, and natural gas distribution.

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[18] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we do *not* include emissions caused by methane leakage from the natural gas distribution system within the electric sector and instead reference this source of emissions within the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

Rhode Island's first greenhouse gas emissions inventory was completed in 2013 with the support of experts from the Northeast States for Coordinated Air Use Management.[19] This first analysis estimated both a 1990 baseline and emissions inventory for 2010, the most recent year for which data was available at the time. Since this first analysis, RIDEM has continued to complete annual emissions inventories. In the sections below, we provide a high-level summary of how emissions are estimated and highlight changes since the *2016 Plan* was developed.

In the spirit of focusing our efforts around the most impactful and immediate priority actions to reduce Rhode Island's emissions, we limit the discussion in this chapter to the emissions sources that have readily available solutions for decarbonization. Therefore, we provide in-depth descriptions and discussions of methodologies for the three largest contributors to Rhode Island's greenhouse gas emissions: transportation, electricity consumption, and residential heating. We do not provide in-depth discussions of how we estimate emissions from commercial heating, industry, natural gas distribution, waste, or agriculture – each of these sources, while critically important for reaching net-zero emissions, is small in comparison and has relatively limited or nascent solutions for decarbonization. We recommend further attention to these sectors in the development of the *2025 Climate Strategy*. We do, however, provide an in-depth discussion of methodology and considerations around estimating the emissions impacts of land use, land use change, and forestry (LULUCF).

The Role of Models

> *A model is a way to describe something that happens in the world around us. A model does not dictate what happens, nor does a 'right' model exist. Models are tools that we use to understand how one variable affects another. In this vein, it is important to understand the value of – and the limitations of – the models we employ.*
>
> *A model should be as simple or complex as needed to attain the requisite levels of precision and accuracy given objectives and available resources. A simpler model typically needs fewer resources than a complex model because there is less data to be collected, less time used to run the model, etc. If a simple model is sufficiently precise and accurate for the user, then there is negligible value to making the model more complex.*
>
> *Precision is the concept of how reproducible the results of the model are – a precise model consistently gives similar results. However, a precise model may give consistently inaccurate results. In statistics, we can estimate precision using established methods and tests. For example, an econometric model reports out what-are-called 'standard errors,' which help a user understand whether the model's results are the result of real underlying relationships or are spurious.[20] Precision is important to understand when we compare results because it would be inappropriate to attribute differences between imprecise results to a specific reason. You might hear terms like 'statistical significance', 'variability', and 'uncertainty' when discussing precision.*
>
> *Accuracy is how close a model's results are to the truth, which may or may not be known. An accurate model may not be precise. If a model is expected to consistently underestimate or*

[19] Northeast States for Coordinated Air Use Management (NESCAUM) is a non-profit organization: https://www.nescaum.org/.

[20] Precision is a concept that exists across disciplines. For example, engineers may be familiar with the concept of 'tolerances' to describe required precision of machining and manufacturing. Scientists have developed standardized methods for assessing precision of measurements, such as by completing multiple counts of the same sample or by taking multiple samples of the same population.

overestimate a result, then we say that result is 'biased'. In the models we use to estimate Rhode Island's emissions, it is the responsibility of the people doing the estimation to understand if and how results are biased.

Results from any model should not live in isolation, and any isolated facts or figures should be considered incomplete results. Complete results must discuss precision and bias, and should include discussion of the validity of the model.

The methodology used to estimate Rhode Island's greenhouse gas emissions inventory does not report any measures of precision or imprecision. However, the SIT does provide some helpful insights into uncertainties in the default data provided. RIDEM assesses the validity of the data and the factors that influence emissions to inform their understanding of how precise our emissions results are, especially as we compare emissions year-over-year. Having some standardized guidance from the US EPA on the precision of their models' results would help Rhode Island (and other states) properly contextualize emissions inventory results.

- States should request the US EPA develop methods to assess precision to be integrated into their emissions inventory tools.

Transportation Sector Emissions

Emissions from the transportation sector include emissions from highway vehicles,[21] aviation, marine transportation, gas and diesel off-road vehicles, locomotives, and more.

Table X. Emissions from the Transportation Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Transportation Total	**4.97**	**4.33**	**4.40**	**4.19**	**4.59**	**4.25**	**4.09**	**3.94**	**4.17**	**4.45**	**4.29**
Aviation	0.33	0.27	0.31	0.29	0.29	0.30	0.28	0.30	0.34	0.38	0.30
Highway Vehicles	4.38	3.70	3.76	3.62	4.10	3.62	3.66	3.62	3.57	3.85	3.61
Nonroad Sources	0.27	0.36	0.33	0.28	0.20	0.32	0.12	0.02	0.25	0.23	0.38

Bottom-Line Factors that Reduce Transportation-Sector Emissions

1. Reducing fuel use reduces emissions
2. Using lower-emissions fuels (like electricity) reduces emissions

Current Method

Several tools are available to calculate greenhouse gas emissions from the transportation sector. The US EPA recommends the SIT for the entire sector and the Motor Vehicle Emissions Simulator (MOVES) for highway vehicles only. The SIT and MOVES models vary in the amount of precision at the state level.

[21] A highway vehicle is any type of on-road vehicle (e.g. passenger car, passenger truck, light commercial truck, heavy-duty trucks, etc.) that uses any fuel type.

The SIT uses a top-down approach to calculate emissions from transportation, starting with fuel consumption and vehicle miles traveled. This approach uses data on fuel sales within each state as a proxy for fuel consumption. The major shortcoming of this method is a lack of detail; drivers do not always use their vehicles in the same state that they purchase fuel. As a result, fuel sales may provide an imprecise estimate of fuel consumption at the state level. Data on fuel sales also do not provide information on different types of on-road vehicles.

MOVES is an all-in-one program that estimates emissions using a “bottom-up” approach. Vehicle miles traveled and vehicle data determine fuel consumption and emissions produced. The tool requires many user-supplied inputs and simplifies the analysis at different geographic levels. For the purpose of state emissions inventories, US EPA recommends county level inputs requiring the user to supply local, state, and county data. Inputs to MOVES include data on vehicle population, vehicle age, average speed distribution, meteorological data, inspection and maintenance program details, road type distribution, and vehicle miles traveled. The model simulates vehicle drive cycles for the defined time period and geographical area specified. Data from all five Rhode Island counties are summed to produce a transportation sector inventory.

Although MOVES provides the strongest and most current methods for analyzing the greenhouse gas emissions of on-road vehicles, the tool is not the best option for estimating emissions from non-road modes of transportation. Instead, the SIT is used to determine emissions from aviation and other non-road sources. Some examples of non-road sources are boats, locomotives, tractors, construction equipment, snowmobiles (gasoline only), and lubricants. For aviation related greenhouse emissions, the Rhode Island Airport Corporation (RIAC) provides RIDEM with an annual inventory of greenhouse gas pollutants associated with the State’s primary airport, T.F. Green International Airport.

Notable Changes

Rhode Island’s emissions inventories for years 1990, 2010-2012, 2018, and 2019 used the SIT only; those inventories did not use MOVES to estimate emissions from highway vehicles. MOVES was used for years 2013-2017 to estimate emissions from the highway vehicle sub-sector. As such, transportation emission totals for years 1990, 2010-2012, 2018, and 2019 should be interpreted as being less precise than transportation emissions for years 2013-2017.

Notes on the 1990 Baseline

The 1990 baseline was estimated using only the SIT. Transportation emissions today relative to the existing 1990 baseline would not be an apples-to-apples comparison because the core methodology is different.

Limitations of the Model

The SIT distinguishes between alternative fuel vehicles and petroleum-powered vehicles. Categories of alternative fuel vehicles include methanol, compressed natural gas, liquified petroleum gas, and ethanol. Electric vehicles are not considered alternative fuel vehicles in the SIT. Emissions resulting from the electricity consumed in charging electric vehicles are also accounted for in the electricity consumption sector of Rhode Island’s greenhouse gas emissions inventory. MOVES also does not distinguish between electric and non-electric vehicles, which results in overestimating emissions from electric vehicles in two ways.

First, because the tools cannot distinguish between electric and non-electric vehicle types, emissions from electric vehicles are assumed – incorrectly – to be equivalent to emissions from gas-powered vehicles.

Fortunately, emissions from electric vehicles using electricity from the renewable- and fossil-based generators we have today are less than the emissions from gas-powered vehicles.

Second, the emissions from electric vehicles are double counted because they appear (incorrectly) in the transportation sector emissions estimates and (correctly) in the electric sector emissions estimate. Currently, this overestimation is negligible since electric vehicles comprise only a small portion of the Rhode Island market (as of 2021, slightly less than one percent of vehicles registered were electric). This overestimation will grow as more and more Rhode Islanders adopt electric vehicles.

- States should request the US EPA amend the greenhouse gas emissions inventory tools to correctly account for emissions resulting from electric vehicles.

Electric Sector Emissions

Emissions from the electric sector result from electricity consumed[22] within Rhode Island. Rhode Island's increasing Renewable Energy Standard and continued energy savings from energy efficiency programs, both of which reduce emissions, have mitigated the magnitude of emissions increase that we would have seen absent those activities.

Table X. Emissions from the Electric Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018*	2019
Electricity Consumption	2.82	2.29	3.38	3.38	3.52	3.25	3.21	2.84	3.31	2.33	2.05

** Revised 2018 electricity sector emissions*

Bottom-Line Factors that Reduce Electric Sector Emissions

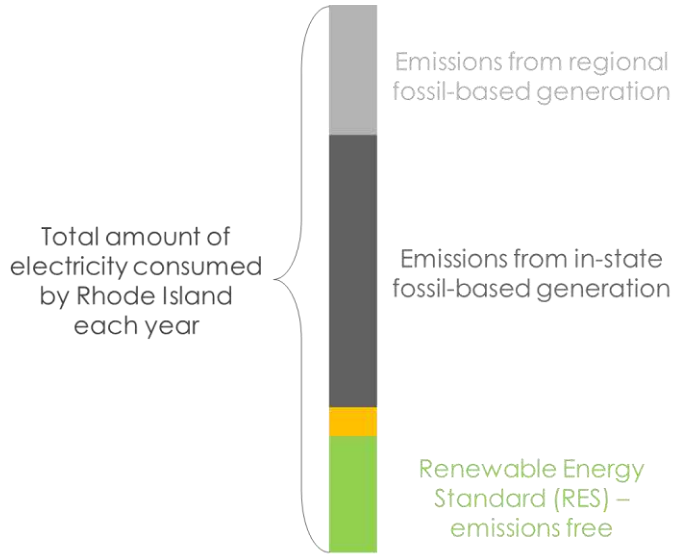
1. Reducing electricity consumption reduces emissions.
2. Producing electricity with renewable energy reduces emissions and appropriately crediting RIs investment in renewable energy in the inventory

Current Method

Rhode Island's current method for estimating emissions from the electric sector is based on annual state-wide electricity consumption. Both Massachusetts and Connecticut also rely on this method for their annual emissions inventory. The electric sector emissions inventory includes three primary components (illustrated in the figure below): compliance with the Renewable Energy Standard (RES),[23] emissions of in-state fossil-based electricity generation, and emissions of fossil-based electricity from our regional electric grid.

[22] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we do *not* include emissions caused by methane leakage from the natural gas distribution system in this section and instead reference this source of emissions within the section on emissions from the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

[23] RIGL 39-26



First, we account for emissions-free electricity in compliance with Rhode Island's RES, requires we meet an increasing portion of our electricity consumption with renewable energy. Electric distribution companies and non-regulated power producers comply with the RES by supplying an increasing percentage of their retail electric sales from renewable energy resources. Eligible renewable energy resources include solar, wind, wave, geothermal, small hydropower, biomass, and fuel cells.

RES compliance does not involve the physical delivery of electricity produced by renewable energy facilities. Instead, electricity providers meet the requirements of the RES mandate by purchasing renewable energy certificates (RECs), which each represent the environmental attributes associated with one megawatt-hour (1 MWh) of renewable energy generated and delivered to the electric grid at some point throughout the year.

RES compliance can also be demonstrated by making alternative compliance payments (ACPs) to the Rhode Island Commerce Corporation (Commerce RI) Renewable Energy Fund. The ACP functions as a price ceiling, allowing electricity providers to comply with the RES mandate if REC shortages occur. Commerce RI uses the Renewable Energy Fund (REF) to support the development of new renewable energy projects. In turn, these projects generate RECs, theoretically helping to ameliorate tightening of the REC market.

This portion of electricity consumed that resulted in ACPs rather than retiring RECs cannot be considered to be emissions-free. Rather, this portion of our electricity consumption has emissions proportional to the emissions resulting from our in-state and regional electric grids. Emissions from this portion of electricity consumption comprise Rhode Island's total electric sector emissions – as we increase the RES, all else equal, emissions will decrease. We estimate these emissions by first assuming all in-state fossil-based electricity generation is consumed in state, and then pro-rate emissions from regional fossil-based electricity generation required to be imported into the state to satisfy consumption. As other states enact RES-like mandates and as market dynamics evolve to favor lower-emissions generation, emissions will decrease, all else equal.

We can walk through this method using the 2018 emissions inventory as an illustrative example; these steps are also detailed in the figure below. In 2018, Rhode Island consumed approximately eight billion kilowatt-hours (kWh) of electricity.[24]

In 2018, the RES required 13% of electricity consumption be met with renewable energy. Of this 13%, nearly all was offset through the purchase (and retirement) of RECs. This portion of electricity consumed – equal to about 1 billion kWh – is deemed to have zero emissions.[25] The small portion of compliance through ACPs – roughly 30 million kWh – cannot be considered to be emissions-free.

In 2018, Rhode Island had six electricity generators, five of which used natural gas and one of which used landfill gas. These six generators produced a little more electricity than the total amount of electricity Rhode Island consumed in 2018. Therefore, emissions for roughly seven billion kilowatt-hours of emissions-intensive electricity consumed equaled the emissions produced by in-state fossil-based generators.[26] If those power plants had produced less than the equivalent of the amount of electricity consumed by Rhode Island, as was the case in 2016, the emissions from the remaining amount of electricity would be deemed to be proportional to emissions from the fossil-based fuel mix that supplies our regional electric grid.

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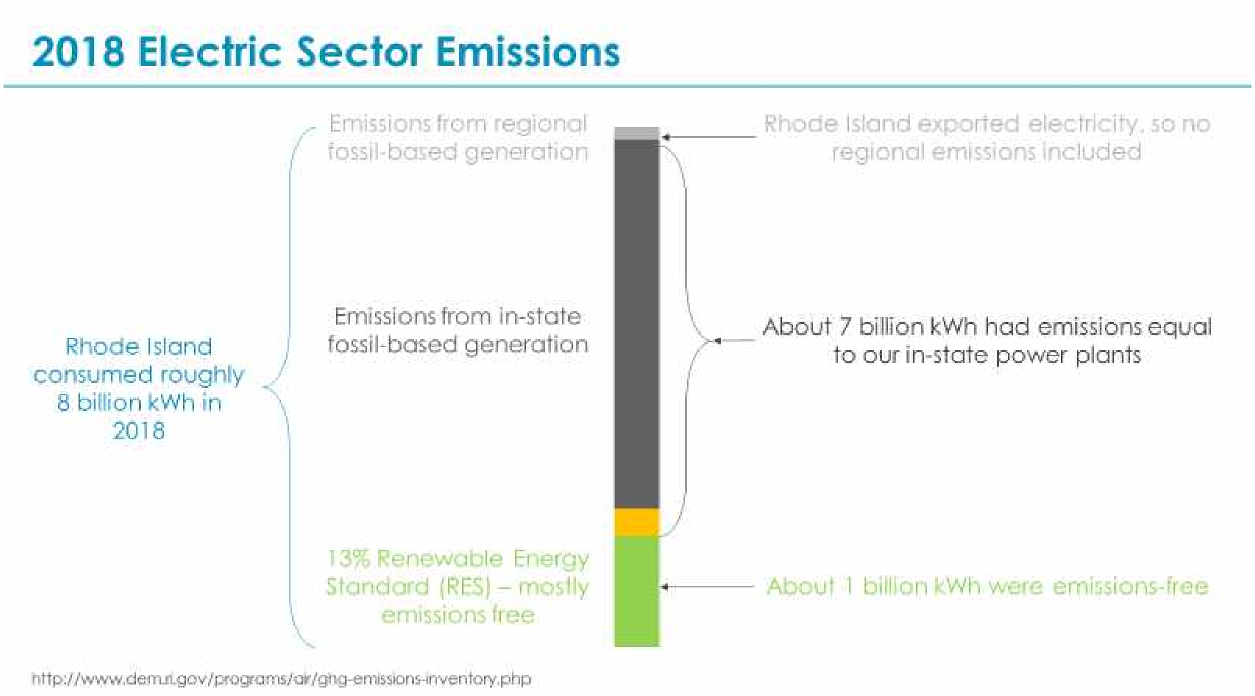
[24] We present electricity consumption in units of kilowatt-hour (kWh) because readers may be familiar with this unit from electricity bills. We could present electricity consumption (or generally) equivalently as 8,000 gigawatt-hours (GWh) or 8 million megawatt-hours (MWh).

[25] Some readers may ask how our retail renewable energy programs fit in here – the answer is that it all depends on who retains ownership of the RECs generated and what they do with them. People who have renewable energy systems through the REG program (National Grid's feed-in-tariff program) sign over ownership of all RECs generated to the utility. The utility then retires those RECs to meet its own obligation under RES – in other words, those RECs count toward reducing Rhode Island's emissions. In contrast, people who own their own renewable energy systems that are net metered retain ownership of the RECs generated for those systems. In order to measure the RECs generated, these systems need additional technology that meets required specifications (i.e. a revenue-grade meter to measure renewable energy production). For residential systems, individuals usually don't install this technology. Therefore, the generation of these systems doesn't count toward Rhode Island's compliance with RES, but it does have the effect of reducing our statewide electricity consumption. From 2018, Rhode Island consumed eight billion kilowatt-hours of electricity *plus* the amount of emissions-free electricity generated by these direct-owned net metered systems. Net metered systems that are direct owned or owned by third parties, and that have the technology to measure REC generation (this is more common for commercial systems), may have their RECs sold to meet Rhode Island's RES *or* another state's RES. If the RECs are retired in Rhode Island, then they reduce our emissions. If the RECs are retired in another state, then they reduce that other state's emissions.

[26] Some readers may ask how Rhode Island's participation in the Regional Greenhouse Gas Initiative (RGGI) fits in – the short answer is that it helps us reduce our carbon dioxide emissions both regionally by encouraging carbon abatement measures and generating revenue to support emissions reductions. If our in-state fossil-based generators abate their emissions to comply with RGGI, then Rhode Island's emissions decrease. If those generators instead buy allowances to produce emissions, then we receive some portion of revenue that we then allocate to programs like energy efficiency and renewable energy incentives, which in turn reduce our emissions.



Annual versus Hourly Electric Sector Emissions

The emissions that result from consuming a unit of electricity on a hot, humid summer evening are different from the emissions that result from consuming the same unit of electricity on a pleasant fall day. This is because the systems that generate electricity differ based on time of day and how much electricity is needed.

On hot and humid summer evenings, when individuals are getting home from work and turning their air conditioners on, the region typically needs the most electricity out of the entire year (called 'peak electricity demand').[27] *Our region's renewable energy sources tend to generate less electricity during summer evenings (when the wind calms down and the sun sets), so our electricity needs must be met by fossil-fueled electricity generators. To satisfy electricity demand during these peak hours, the New England electric grid relies on additional natural gas power plants and occasionally on oil- and coal-based power plants (less than one percent of the region's electricity comes from these highest-emitting sources). Therefore, emissions from overall electricity consumption and emissions per unit of electricity consumed both increase during times of peak electricity demand.*

In contrast, on pleasant fall days we tend to leave our heating or air conditioning systems off, and since individuals tend to be at work, we aren't running appliances like dishwashers and washing machines. During these times, our renewable energy resources tend to have more output, too. The relatively small amount of additional electricity we need to satisfy our demand during these off-peak hours can be derived from our region's emissions-free nuclear power plants plus some natural gas power plants. Therefore, at certain times of the year, like pleasant fall days, our

[27] The timing of when peak electricity demand occurs is anticipated to shift to winter months as we electrify thermal and transportation sectors. For more information about peak demand, visit the US Energy Information Agency.

emissions are lower both because we consume less electricity and the little electricity we consume comes from sources with relatively low emissions.

Rhode Island's current practice and capability is to estimate emissions on an annual basis, but this method does not distinguish between electricity used at times when resulting emissions are high and electricity used at times when resulting emissions are low. For example, electricity produced using renewable energy resources generates RECs which can be used to offset emissions from fossil-based electricity generated at any time of the year – the RECs are not specific to a single hour. Rhode Island and its regional partners should revisit the idea of more granular emissions accounting as technology and capabilities allow within the next decade.

Notable Changes

Prior to the 2016 emissions inventory, Rhode Island used the SIT to account for electric sector emissions. However, the SIT does not accurately account for emissions reductions from state policies like the RES. This change in methodology prevents robust comparison of electric sector emissions before and after 2016.

Notes on the 1990 Baseline

The 1990 baseline was originally estimated with the SIT. After the publication of the *2016 Plan*, the 1990 baseline's electric sector emissions were adjusted. Comparing electric sector emissions today relative to the existing 1990 baseline would not being comparing apples-to-apples because the underlying methods differ.

Limitations of the Methodology

This methodology does not account for the varying rates of emissions across hours of the year. Renewable energy systems generate more electricity during times when the marginal fossil-fueled power plant uses natural gas. However, peak electricity demand occurs when the marginal power plant uses a more emissions-intensive fuel. Since RECs produce by renewable energy are not time-stamped, those RECs may theoretically offset more emissions-intensive electricity consumption than the renewable energy resources actually did. Therefore, this methodology is likely to result in underestimating emissions from the electric sector. See the callout box on *Annual versus Hourly Emissions* for additional discussion. Methodology changes for the most recent inventory year, 2019, are discussed in the *2019 Rhode Island Greenhouse Gas Emissions Inventory*. We suggest consistent revisions to the electricity sector methodology as accounting capabilities and economic markets evolve.

Impacts of Strategic Electrification

Strategic electrification is one pathway to reducing greenhouse gas emissions. By transitioning transportation and heating away from technologies that require fossil fuels to those that use electricity – and then meeting our growing electricity needs with renewable energy resources – we will reduce emissions in the transportation and heating sectors. [28]

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[28] The GHG emissions from registered in Rhode Island (i.e. from charging) are counted in the electricity sector, not the transportation sector. When there are significantly more EVs registered in Rhode Island, their vehicle mile traveled (VMT) contribution will be omitted from the overall VMT. This will avoid double-counting their emissions between the transportation and electricity sectors. Since VMT from EVs would be omitted from the transportation sector, overall transportation sector emissions would DECREASE. The 2033 100% RES should mitigate additional emissions by EVs in the electricity sector. In theory, we could adopt as many EVs as we want and still have 0 MMTCO2e with the electric sector by 2033.

As we electrify heating and transportation, a growing proportion of heating and transportation emissions will be captured within the electric sector emissions inventory. This has two effects. First, to the extent our thermal sector and transportation sector emissions inventory tools account for electrification, the decreases we will see in emissions in transportation and heating sectors will be exaggerated because those emissions will be included in the electric sector emissions inventory. We will need to make sure we use caution when using sector-specific emissions to assess the efficacy of our climate strategies to avoid thinking we have made more progress than we actually have. Second, emissions in the electricity sector will grow as people electrify their vehicles and heating systems. This growth in electricity consumption – and, depending on timing of renewable energy deployment, of electric-sector emissions – may result in obscuring progress we are actually making with our climate strategies.

- *For these reasons, among others, it is important for Rhode Island to track metrics beyond greenhouse gas emissions in order to evaluate progress accurately and clearly. Such metrics may include, but are not limited to, proportion of vehicles that are electric, census of heating system fuel types, prevalence of these technologies across communities, and others.*

We also have to be increasingly careful with our terminology. 'Thermal sector emissions,' which is comprised of residential heating, commercial heating, industrial heating and processes, and natural gas distribution, may become an increasingly incomplete representation of all emissions from the thermal sector. 'Electricity sector emissions' as used in the emissions inventory will increasingly include more end uses than in the past and therefore may take on a broader interpretation than is used colloquially today.

- *If, and until, we have tools that disaggregate state-level electricity consumption by end use, we must strive to be more precise in our choice of terminology. Instead of shortening to 'thermal sector emissions', we should strive to say 'emissions from combustible fuels used for heat'; instead of 'transportation sector emissions', say 'emissions from combustible fuels used for transportation.'*

Residential Heating Emissions within the Thermal Sector

Emissions from the thermal sector result from the sub-sectors of residential heating, commercial heating, industrial processes that require heat, and natural gas distribution. [29] Residential and commercial heating include space heating, water heating, and cooking. The five sub-sectors are each estimated separately. Emissions resulting from heating, cooking, and heat processes that use electricity are captured in the electric sector emissions inventory and are not reflected in the thermal sector inventory. [30] Below, we describe the methodology used to estimate emissions from residential heating only.

[29] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we instead include this source of emissions within the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

[30] Since cooling relies on electricity, emissions resulting from cooling – residential, commercial, or other – are captured in the electric sector emissions inventory.

Table X. Emissions from the Thermal Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential Heating	2.37	2.24	2.15	2.08	2.27	2.34	2.46	1.84	1.87	2.32	2.09
Commercial Heating	1.15	0.92	0.87	0.79	0.91	1.13	1.00	0.86	0.88	0.98	0.94
Industry	0.81	1.04	1.06	1.05	1.24	1.14	1.12	1.14	1.12	1.19	1.03
Industrial Heating	0.71	0.61	0.56	0.54	0.67	0.57	0.59	0.61	0.62	0.63	0.61
Industrial Processes	0.09	0.43	0.5	0.51	0.56	0.57	0.53	0.53	0.50	0.55	0.42
Natural Gas Distribution	0.3	0.15	0.15	0.15	0.17	0.17	0.16	0.15	0.15	0.14	0.14

Bottom-Line Factors that Reduce Thermal Sector Emissions

1. Reducing combustible fuel use (like natural gas, oil, and propane) reduces emissions.
2. Using lower-emissions fuels (like biodiesel or electricity) reduces emissions.

Current Method

Residential heating emissions are estimated using the SIT's Carbon Dioxide from Fossil Fuel Combustion (CO_2FFC) module and the Stationary Combustion module. The US Energy Information Administration (EIA) collects fuel consumption data throughout the United States by requiring mandatory surveys for all companies that deliver natural gas to consumers, usually through pipelines, or transport natural gas across state lines.

Distillate fuel, propane, and kerosene are examples of fuels that are usually trucked to Rhode Island homes that use them for heat. These are therefore called 'delivered fuels'. Consumption estimates for delivered fuels are estimated by the EIA. Fuel consumption data is a key component to estimate emissions.

Notable Changes

There have not been any appreciable changes to methodology for estimating emissions from residential heating.

Notes on 1990 Baseline

The 1990 baseline is fairly comparable to current emissions inventories; the methodology has not changed. However, there has been a change to a specific parameter used to account for the impact different types of emissions on climate change – this parameter is called global warming potential (GWP) and it is particularly important within estimating thermal sector emissions because of the types of greenhouse gases associated with thermal sector emissions. See the following section on When to Update the 1990 Baseline for more information. Rhode Island's 1990 baseline and 2010 emissions inventory used different GWPs than emissions inventories for 2011-2019. Comparing emissions from our 2019 emissions inventory to the 1990 baseline is not a direct comparison. However, the effect of this change in GWPs is likely to be small relative to total emissions.

Limitations of the Model

Rhode Island enacted and subsequently updated the Biodiesel Heating Oil Act to require the mixing of biodiesel in heating oil. Biodiesel is a renewable fuel made from plant or animal based materials or waste. Biofuel can be mixed with conventional heating oil to create different blends of oil. For example, a B5 blend contains 5% biodiesel and a B50 blend contains 50% biodiesel. In 2019, Rhode Island required a B5 blend. The Biodiesel Heating Oil Act requires Rhode Island to be at least a B50 blend by 2030.

Biodiesel reduces emissions because it burns cleaner than conventional oil. Currently, biodiesel is not included in the emissions inventory due to a lack of state-level data on biofuel consumption. Residential heating emissions are likely to be overestimated because this inventory's calculations do not include the use of blended biofuels, and this overestimation is likely to be exacerbated as we increase biofuel blending.

- We recommend modifying tools and methods to account for blending of biodiesel by 2025 (i.e. for the 2022 emissions inventory). Strategies to do so include joining with other states to request that the EPA modify their tools or developing an alternative methodology specific to Rhode Island's needs.
- We recommend including supplemental analyses like this at key intervals to gain better insight into the efficacy of our actions.

When to Normalize

One key driver of emissions from the thermal sector is the year-to-year variation in how cold our winters are. Due to larger-scale climate processes and natural stochasticity of weather, some winters are colder than others, which lead to using more fuel to heat, and therefore to higher emissions. The opposite is true, too – warmer winters mean less heating is required and therefore less fuel is burned, resulting in fewer emissions. Since each year is different, it makes it hard to feel like were comparing apples-to-apples across years.

One way to track progress over years is to 'normalize' emissions for weather conditions. 'Normalizing' is a common process in data analysis in which you factor out whatever exogenous variable might be preventing you from seeing clear trends. For example, we can measure how cold a winter is by calculating the number of what-are-called 'heating degree days.' Heating degree days provide useful information about the coldness or warmness of any particular winter. Heating degree days are calculated by subtracting the average daily temperatures from a baseline temperature of 65°F. 65°F is deemed to be the temperature at which neither air conditioning nor heating are required to maintain a comfortable indoor temperature. The concept of heating degree days is tricky because there can be multiple heating degree days in a 24-hour period.

There are various ways to normalize emissions for heating degree days, the simplest of which is to divide emissions by the number of heating degree days each year. If emissions per heating degree day decreases over time, then we can say with confidence that we are reducing our emissions from heating. Another factor we might consider normalizing emissions for might be population. As population grows in Rhode Island – something that is arguably uncontrollable – then we expect higher emissions. However, we will be more convinced that our strategies to reduce emissions are working if emissions per person decrease over time.

Land Use, Land Use Change, and Forestry

As discussed in the Defining Net-Zero Emissions by 2050 chapter, how we use our lands and preserve our forests impacts our greenhouse gas emissions. The land use, land use change, and forestry (LULUCF) sector of our emissions inventory captures this impact.

Bottom-Line Factors that Impact LULUCF Emissions

Further avoidance of forest loss helps steady Rhode Island's ability to sequester carbon.

Current Method and Limitations

Rhode Island's small and diverse landscape is inherently difficult to account for LULUCF. 1990's LULUCF sector was estimated through a one-time contract with the NESCAUM and is not replicable. Additionally, the 2010 LULUCF estimate was calculated through the Long-range Energy Alternatives Planning (LEAP) model used in the *2016 Plan* and is not replicable. Beginning with inventory year 2019, RIDEM now estimates LULUCF with in-house data from RIDEM's Division of Agriculture and Forest Environment (DAFE) and some data from the EPA's SIT.

Carbon sequestration from forest land and urban trees, or settlement trees, account for the lion's share of LULUCF. RIDEM estimates both with in-house data provided by DAFE. Data on forest fires in Rhode Island are also provided by DAFE. The remaining LULUCF subsectors (yard trimmings, settlement soils, and agricultural soils) are derived from the SIT and comprise less than 5% of the LULUCF sector. More information on the methodology used to estimate carbon sequestration can be found in the *2019 Rhode Island Greenhouse Gas Emissions Inventory*. 2019's LULUCF sector represents a **first step** towards reliably estimating carbon sequestration in Rhode Island. This methodology should not be compared with other state's carbon removal sectors.

- We recommend RIDEM continue to collaborate with its DAFE and the U.S. Climate Alliance to continuously improve the LULUCF sector. The methodology should be replicable, consistent, and conducted in-house.
- We recommend estimating emissions from LULUCF at least every year in which we assess compliance with the 2021 Act on Climate. If the administrative burden of estimating LULUCF emissions is low and the expected variation in LULUCF emissions is high, then we may choose to estimate LULUCF more frequently.

1990 Baseline

In 2016, LEAP modeling completed for the *2016 Plan* estimated that LULUCF in Rhode Island removed 0.29 $MMTCO_2e$ in 1990. This model failed to be replicable, so we cannot make accurate comparisons to 1990's LULUCF sector.

- We recommend further evaluation of using a replicable methodology for annual emissions inventories to re-estimate emissions from the 1990 baseline and subsequent years through 2018.

When to Update the 1990 Baseline

The 2021 Act on Climate sets forth greenhouse gas emissions reduction mandates relative to a 1990 baseline: reduce emissions by 45% below 1990 levels by 2030 and reduce emissions by 80% below 1990 levels by 2040. Therefore, the 1990 baseline is a critical piece of benchmarking Rhode Island's progress.

However, over time methods and models evolve to accommodate the best science. Preserving our original estimate of emissions in 1990 memorializes consistency, but results in inaccurate comparisons over time.

Updating the 1990 baseline can help us understand our emissions reductions on an apples-to-apples basis with our contemporaneous emissions inventory.

One notable example is the change to a specific parameter used to account for the impact different types of emissions on climate change – this parameter is called global warming potential (GWP). This parameter is updated routinely to reflect the most current and robust science (the impact of the emissions does not change over time, but our understanding of the impacts does). Table X shows how GWPs have changed over time.

Table X. Global Warming Potentials (GWPs)

Global Warming Potentials (GWPs)				
Type of Greenhouse Gas	IPCC Second Assessment Report (SAR)	IPCC 4th Assessment Report (2007)	IPCC 5th Assessment Report (2014)	IPCC 6th Assessment Report (2022)
Carbon dioxide (CO_2)	1	1	1	forthcoming
Methane (CH_4)	21	25	28	forthcoming
Nitrous oxide (N_2O)	310	298	265	forthcoming
Use in Rhode Island's GHG Emissions Inventories:	1990 baseline, 2010	2011-2019	N/A	N/A

Rhode Island's 1990 baseline and 2010 emissions inventory used different GWPs than emissions inventories for 2011-2019. Comparing emissions from our 2019 emissions inventory to the 1990 baseline is not a direct comparison. However, the effect of this change in GWPs is likely to be small relative to total emissions.

- We recommend further evaluation and discussion of updating the 1990 baseline if the best science suggests new and reasonable parameters or methods.

Assessing Compliance

The greenhouse gas emissions reduction mandates set forth in the 2021 Act on Climate are both mandatory and enforceable. Therefore, Rhode Island needs a clear, transparent, and comprehensive way to assess compliance with those mandates.

- We recommend RIDEM evaluate in 2023 the benefits of promulgating such regulations.

Since 2016

The 2021 Act on Climate requires this *2022 Update* to "submit to the Governor and the General Assembly an update to the greenhouse gas emission's reduction plan dated 'December 2016'." Since 2016, we've had six years of experience, progress, and lessons learned. We present this information in three different ways.

First, we review the metrics we've been tracking since 2016 – these metrics represent an outcome-oriented snapshot of how we've worked to reduce greenhouse gas emissions in Rhode Island.

Second, we inventory the numerous studies, programs, policies and pieces of legislation that have contributed to our experience with climate mitigation, resilience, and adaptation since 2016 – by doing so, we provide an easy reference for readers to connect to these resources and learnings.

Third, we directly describe progress made (or in some instances, not made) on each pathway from the 2016 Plan – these descriptions supplement the outcome-oriented metrics with a process-oriented narrative.

Some readers may find this chapter to feel repetitive – it is by design. We are attempting to describe our actions since 2016 in multiple ways, with each providing a different perspective, level of detail, and intention for use moving forward.

A Snapshot of Metrics Since 2016

For this section, we leverage the framework of metrics from the "RI Snapshot" climate dashboard maintained by the Rhode Island Department of Environmental Management.[31] The Executive Climate Change Coordinating Council (RIEC4) and its Advisory Board are developing the outline for a new climate dashboard throughout 2022, to be developed beginning in 2023.

Greenhouse Gas Emissions

Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record[32] – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Clean Energy

As of July 2022, the state has counted approximately 1,149 MW of clean energy generation capacity. Of Rhode Island's current 1,149 MW total, 430 MW is offshore wind which is mostly under contract for the Revolution Wind facility scheduled to come online in 2026, 527 MW is solar, 148 MW is onshore wind, 35 MW is landfill gas/anaerobic digestion, and 9 MW is small hydroelectric power. Including the 400 MW Revolution Wind project, approximately 85 percent of Rhode Island's current clean energy portfolio is comprised of in-state renewables or projects scheduled for adjacent federal waters. The Power Purchase Agreement for Revolution Wind was approved in 2019 with construction expected to commence in 2024.

[31] RI in the Fight Against Climate Change: A Snapshot

[32] There is a three-year lag between the release of Rhode Island's greenhouse gas emissions inventory and the year in which emissions occurred. See the 'Greenhouse Gases' chapter for more information about Rhode Island's greenhouse gas emissions inventory, methodology, and tools.

Energy Efficiency

Since 2016, energy savings from utility energy efficiency programs has been accumulating. Table X shows energy savings for both electric and gas efficiency programs. Annual savings are savings which occur in a single year. Lifetime savings are estimated over the expected duration of installed efficiency measures.

Table X. Energy Savings from Energy Efficiency Programs 2016-2021

	National Grid	**Pascoag Utility District**	**Block Island Utility District**[33]
Electric Annual Energy Savings Cumulative 2016-2021	1,128,943 MWh	671 MWh	10 MWh
Electric Energy Savings Cumulative over Expected Lifetimes of Measures Installed 2016-2021	10,166,520 MWh	3,980 MWh	59 MWh
Gas Annual Energy Savings Cumulative 2016-2021	2,468,022 MMBtu	Not Applicable[34]	
Gas Energy Savings Cumulative over Expected Lifetimes of Measures Installed 2016-2021	26,327,149 MMBtu		

Heating

Residential and commercial heating contribute 28% of Rhode Island's greenhouse gas emissions, and industrial heat processes contribute another 9.5%.[35] In 2017, roughly half of Rhode Island homes used natural gas for heating, a third used fuel oil, a tenth used electricity, and the remainder used another fuel like propane or wood.[36]

Green Jobs

In 2021, Rhode Island had 13,809 clean energy jobs.[37] The economic aftermath of COVID-19 resulted in the loss of roughly four years of clean energy job growth, sending Rhode Island's clean energy economy back to 2016 employment levels. Clean energy job losses represented about seven percent of all jobs lost in Rhode Island's overall labor market in 2020. This decline marks the first year of job losses since the state began tracking clean energy employment in 2014. Prior to COVID-19, Rhode Island's clean energy sector had experienced a 77% increase in jobs since 2014.

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[33] Energy savings for Block Island Utility District are for November 2020 through December 2021; data do not do not include savings from the *Block Island Saves Pre-Pilot* (2015-2016) or *Full Pilot* (2016-2017). For more information about Block Island Saves, please see the Final Report.
[34] Neither Pascoag Utility District nor Block Island Utility District operate a gas distribution system or offer gas supply.
[35] 2019 Greenhouse Gas Emissions Inventory
[36] 2017 Rhode Island Renewable Thermal Market Development Study
[37] 2021 Clean Energy Industry Report

Impacts of COVID-19 – A 2020 Summary

While COVID-19 has severely disrupted life for all communities and businesses, the presence of COVID-10 does not lessen the urgency of climate change. That the 2021 Act on Climate passed in 2021 – amidst COVID-19 – is a testament to our need to mitigate the most severe impacts of climate change today and into the future. We have to be cognizant of pressures facing Rhode Islanders and consider these forces when developing future policies and programs, but climate mitigation and adaptation needs to continue to avoid overburdening communities with avoidable costs down the road.

Over the past couple years, we have felt the impacts of COVID-19 throughout our programs and our economy. We describe some but not all of the impacts here to provide some context for our progress. We discuss related impacts from supply chain distributions and real estate market dynamics elsewhere.

The economic aftermath of COVID-19 resulted in the loss of roughly four years of clean energy job growth, sending Rhode Island's clean energy economy back to 2016 employment levels. Employment across clean energy businesses declined by over 2,500 jobs (15.5%) between the last quarters of 2019 and 2020. By comparison, the overall statewide labor market declined by 7.4% during the same time. Clean energy job losses represented about seven percent of all jobs lost in Rhode Island's overall labor market in 2020. This decline marks the first year of job losses since the state began tracking clean energy employment in 2014 – prior to COVID-19, Rhode Island's clean energy sector had experienced a 77% increase in jobs since 2014.

Despite the unexpected shock of COVID-19, Rhode Island's clean energy labor market already appears to be bouncing back. Of surveyed clean energy firms in Rhode Island in the fourth quarter of 2020, four in ten indicated that they had laid off, furloughed, or reduced pay for their clean energy workers as a result of COVID-19. As of the end of 2020, three-quarters of these firms indicated that they had already brought back their laid off or furloughed clean energy staff. Job losses in 2020 were concentrated in March through May, with steady monthly job gains in June through December.

Administratively, COVID-19 made some work more difficult to move forward as facility access to implement projects was more limited in 2020 and much of the planning and stakeholder engagement moved from in-person to fully remote.

In response to COVID-19, energy efficiency programs began providing the option of a virtual home energy audit. Instead of having an energy specialist walk through a participant's home, the participant video conferences with the energy specialist and shares videos and photos of key appliances. Shifting to virtual energy audits has not only demonstrated the industry's ability to safely adapt to COVID-19 conditions, but has been shown to result in increased responsiveness, higher convenience for participants, and may improve equitable access to this resource.

COVID-19 has changed how the RI Infrastructure Bank's (the Bank's) Municipal Resilience Program operates, switching workshops from in person to online events and delaying some municipalities' participation in the program. Despite these challenges, participation in the MRP has remained strong, and online workshop events have allowed for more attendees than typically attend these events.

While the transition to remote meetings happened abruptly (starting with public workshops related to our Heating Sector Transformation report), we do not see any loss in public *participation. On the contrary, attendance at remote events has increased and participation seems to be more robust. These insights have led to continued remote opportunities for stakeholder engagement, opportunities which reduce commute times and costs, obviate the need for some services to enable participation of some people, and are felt to provide comparative benefits like ease of seeing meeting materials and ability to participate either through oral comments or via written chat.*

Even as COVID-19 restrictions ease, many are still suffering from economic and personal losses, and communities and businesses are still recovering. Our climate strategy does not exist in isolation – we must consider this ongoing context within our policies and programs. Climate action today should be designed to help communities and businesses recover by investing in our local economy, putting downward pressure on costs, and supporting improvements with simultaneous public health benefits, all while making real strides toward achieving our climate goals to mitigate the worst impacts of climate change.

Clean Cars

As of October 2022, there are 6,275 electric vehicles registered in Rhode Island. 2847 (45.4%) are Plug-in Hybrid Electric Vehicles (PHEVs), and 3,428 (54.6%) are Battery Electric Vehicles (BEVs). This represents an 1,313% increase in EVs since 2015.[38]

As of December 2022, there are 564 Level II (public and private) charging station ports, and 65 direct current fast charger (DCFC) ports. This represents a 636% increase in charging stations in RI since 2016.[39]

Protected Land

From 2010 through 2015 9,758 acres of land were protected by the state.[40] From 2016 to 2022 an additional 3,585 acres have been protected by the state [41]

Resilient Communities

As of 2022, 27 municipalities have participated in the Rhode Island Infrastructure Bank's Municipal Resilience Program (MRP). The MRP is a new program since 2019 and includes a robust stakeholder engagement approach to resilience planning. MRP workshops have hosted over 600 participants, including municipal staff and community leaders. 350+ potential resilience capital projects have been identified using this locally specialized approach.

As of 2022, 46 resilience projects have been funded through MRP Action Grants - a total of $7.5 million in assistance. 93% of MRP Action Grants have incorporated green infrastructure and/or nature-based solutions. $7 million was allocated to the MRP through the 2021 Beach, Clean Water, and Green Economy Bond, and another $16 million was allocated to the MRP through the 2022 Green Economy Bond.

[38] Source: Rhode Island Division of Motor Vehicles
[39] Source: U.S. Department of Energy, Alternative Fuels Data Center
[40] Source: Rhode Island Department of Environmental Management, State Land Conservation Program, as of 12/31/2021
[41] RIDEM is currently collecting data on conservation projects completed at the local level by municipalities and land trusts and will add these numbers to this total in 2023.

Lead-by-Example

The Rhode Island Lead-by-Example (LBE) program was initiated in 2015. Through the end of 2021, the State has achieved an 12.7% reduction in overall State facilities' energy consumption compared to a 2014 baseline. 95% of State Government electricity consumption is offset by renewables.

In 2021, OER developed the "School Lighting Accelerator Program." This program provides technical assistance and financial incentives to Rhode Island public schools to accelerate the transition to LED lighting with controls. Through the end of 2021, five public schools in Central Falls have been converted to LED with integrated controls saving annually 471,500 kWh or $78,500. Also, 31 communities have received support to convert their municipal streetlights to LEDs with controls, representing nearly 90% of the State, and driving $5.3 million in annual cost savings. 100% of State-owned streetlights have been converted to LED lighting with controls as well.

67% of all State buildings are already or in the process of being converted to LED lighting with controls (through the end of 2021). 120 electric vehicle charging ports have been installed across State properties (through the end of 2021) and 11 solar PV systems have been installed at State facilities. 62 light duty vehicles purchased or leased since December 2015 are zero-emission vehicles (through the end of 2021).

Focus on Equity

> *Disproportionate impacts of COVID-19 on communities of color and major national events illustrating social injustice catalyzed a sincere focus on centering equity throughout our work. Historical systemic inequities have continued into our world today, which result in overburdening under-resourced communities with higher energy costs, worse public health outcomes, lower access to programs and resources, and worse environmental quality – among other things – relative to others. Rhode Island's 2025 Climate Strategy and all future plans must address these inequities. A climate strategy that fails to address climate justice will not be the best strategy for Rhode Island's fight against climate change.*
>
> *Since 2016, we've seen immense growth in understanding about equity generally and climate justice specifically. This understanding should have already been in place, and our level of understanding today is still deficient. However, we are making some progress. While the 2016 Plan omits mention of equity or justice, we have centered these concepts in the recommendations stemming from our more recent studies and we will integrate explicit consideration of equity in the priority actions of this 2022 Update and throughout development of all future climate strategies.*

Studies, Programs, Policies, and Legislation

Since 2016, Rhode Island has conducted over a dozen additional studies, gained six years of additional experience running programs, have enacted a number of important policies and passed a number of important laws. In this section, we review what we've done and what we've learned.

Key Studies Since 2016

Since 2016, the State has conducted a number of in-depth studies deepening our understanding of decarbonization activities and enabling actions. The following list contains major studies either directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning.

The following list of studies is not complete but is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy. This list does not include state plans in which stakeholders and agencies prioritize and plan investments in state infrastructure[42] nor does this list include retrospective evaluations of programs, though such evaluations are crucial to increasing the impacts of these programs. This list also omits studies conducted by federal agencies and non-governmental organizations that add to our understanding and depth of knowledge.

100% Renewable Electricity by 2030 (2020)

http://www.energy.ri.gov/100percent/

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2020, the Rhode Island Office of Energy Resources (OER) conducted an economic and energy market analysis, and developed policy and programmatic pathways, to meet this goal. *The Road to 100% Renewable Electricity by 2030 in Rhode Island* provides economic analysis of the key factors that will guide Rhode Island in the coming years as the state accelerates its adoption of carbon-free renewable resources.

The study considers available renewable energy technologies, including their feasibility, scalability, costs, generation patterns, market value, and local economic and employment impacts, as well as barriers that may hamper or slow their implementation. It identifies ways to leverage competition and market information to ensure reasonable ratepayer costs and manage energy price volatility, while taking advantage of economic development opportunities within the state. Utilizing this information, OER developed specific policy, programmatic, planning and equity-based actions that will support achieving the 100% renewable electricity goal.

Solar Siting Opportunities (2020)

http://www.energy.ri.gov/documents/renewable/Solar%20Siting%20Opportunities%20for%20Rhode%20Island.pdf

In an effort to assist with planning future solar photovoltaic (PV) development within the context of other land-use interests such as conservation, agriculture, and housing development, the Rhode Island Office of Energy Resources (OER) contracted Synapse Energy Economics to develop an estimate of the likely solar potential available within a number of solar siting categories. We conducted this statewide study using a granular bottom-up approach, primarily through the use of geospatial data and geographic information system (GIS) software.

Synapse examined and quantified solar potential for rooftop solar (including rooftops of residential single family, residential multifamily, commercial, industrial, municipal, and other building types); ground-mounted solar on landfills, gravel pits, brownfields, and commercial and industrial developed and undeveloped lots; and in parking lots. These categories were identified by OER as types of locations that could aid in policymakers' decisions for balancing future solar PV development with other land use interests such as conservation, farming/agriculture and housing development.

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[42] Such plans include the Long-Range Transportation Plan, State Transportation Improvement Program, Forest Action Plan, Comprehensive Outdoor Recreation Plan, State Energy Plan, RIPTA's Sustainable Fleet Transition Plan, or local comprehensive planning. We refer interested readers to the State Guide Plan developed and maintained by the Division of Statewide Planning for more information.

The report finds that in aggregate across all six categories analyzed, technical potential for solar is between 3,390 megawatts (MW) and 7,340 MW, or 13 to 30 times the amount of solar that is currently installed in Rhode Island. This translates into 5,560 gigawatt-hours (GWh) to 12,600 GWh of electricity able to be produced. Median estimated upfront prices for these categories range from about $3 to $5 per watt. If this entire technical potential were installed, we estimate that up to 7.65 million metric tons of carbon dioxide (MMTCO2) could be displaced, equal to about 70 percent of Rhode Island's total, current greenhouse gas emissions. However, the feasibility of this, especially in light of high costs, needs to be further examined.

Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs (2022)

Conceptual Framework: https://www.nrel.gov/docs/fy22osti/81960.pdf
Technical and Economic Analysis: https://www.nrel.gov/docs/fy22osti/80556.pdf

From 2019-2022, the Rhode Island Office of Energy Resources, National Grid, Rocky Mountain Institute, National Renewable Energy Lab, Lawrence Berkeley National Lab, and Clean Energy States Alliance partnered on a project supported by the Solar Energy Innovation Network. This 2022 report explores one integrated technical and process concept designed to manage interconnection costs and streamline interconnection timelines to support near-term renewable energy deployment. The report describes a new agreement between renewable energy developers and utilities, informed by a technical and economic analysis. The agreement defines the operational parameters for a renewable energy system, with the goal of reducing risk and cost to all parties. This work provides a foundation upon which states and utilities may build proof of concept.

Resilient Microgrids for Critical Services (2017)

http://www.energy.ri.gov/reports-publications/past-projects/resilient-microgrids-for-critical-services.php

The Rhode Island Office of Energy Resources commissioned the report Resilient Microgrids for Critical Services in 2017. In the wake of multi-day power outages due to severe weather events in recent years, OER sought consultant support for design of a program intended to enhance the energy assurance of critical infrastructure through deployment of distributed energy resources and other means. This effort draws from lessons learned in other states with similar programs. This report describes technologies, procurement strategies, and polices that can contribute to microgrid development.

Power Sector Transformation (2017)

http://www.energy.ri.gov/electric-gas/future-grid/

In November 2017, OER, along with the Division of Public Utilities and Carriers (DPUC) and Public Utilities Commission (PUC), issued a major report on how Rhode Island could develop a more dynamic regulatory framework to enable a cleaner, more affordable, and reliable energy system for the twenty-first century. Goals of transforming the power sector include controlling long-term costs of the electric system, giving customers more energy choices and information, and building a flexible grid to integrate more clean energy generation. This report describes recommendations for four workstreams: 1) utility business models, 2) grid connectivity and functionality, 3) distribution system planning, and 4) beneficial electrification. The recommendations in this report are based on significant stakeholder engagement, staff expertise, and consultation with national experts.

Docket 4600: Investigation into the Changing Electric Distribution System (2017)

http://www.ripuc.ri.gov/eventsactions/docket/4600page.html

From 2016-2017, the Public Utilities Commission investigated how a changing electric distribution system impacted their review of rate structures proposed in future proceedings. The resulting stakeholder report and order adopting the stakeholder report provide "a set of rate design principles and a benefit-cost framework to inform how rates could be set in a way to properly incent National Grid to meet state policies." Importantly, this benefit-cost framework includes societal costs and benefits: greenhouse gas externality costs, criteria air pollutant and other environmental externality costs, and conservation and community benefits. Consideration of these factors provided a basis for which regulators can incorporate climate impacts into their decisions for certain applications.

Heating Sector Transformation (2020)

http://www.energy.ri.gov/HST/

The 2020 Heating Sector Transformation report identified and analyzed the state's potential pathways to thermal decarbonization. It was the result of an Executive Order from July 2019 issued by former Governor Gina Raimondo. The study was led by the Office of Energy Resources (OER) and the Division of Public Utilities and Carriers (DPUC) and conducted by the Brattle Group.

The report identified several different decarbonization pathways, generally categorized into two types: electrification or decarbonized fuels. The findings suggest that several pathways exist that would enable RI to decarbonize the thermal sector by 2050, and also maintain similar overall energy expenses for households to those of present day. Due to a number of factors, including uncertainty around the future rate of technological development, the report recommended that none of the potential decarbonization pathways be foreclosed on, but rather a suite of thermal decarbonization efforts be pursued in the coming years. Work in the coming years should focus on education and laying the groundwork to support several decarbonization avenues.

Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island (2021)

http://www.energy.ri.gov/evplan/

In August 2021, the Rhode Island General Assembly passed bills H5031/S0994 directing the Department of Transportation (RIDOT), the Division of Motor Vehicles (DMV), and the Office of Energy Resources (OER) to "develop, no later than January 1, 2022, a plan for a statewide electric vehicle charging station infrastructure in order to make such electric vehicle charging stations more accessible to the public." In response, RIDOT, DMV, and OER, along with representatives from the Rhode Island Department of Environmental Management (RIDEM) and Rhode Island Department of Health (RIDOH) – collectively the Project Team – *developed Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island*.

The intent of this Strategic Policy Guide was threefold: First, the Project Team reviewed the status quo of electric vehicles and their charging infrastructure, as well as current and prior programming. The purpose of this review was to establish where Rhode Island is with vehicle electrification as we look ahead to 2022. Second, the Project Team distilled needs and recommendations heard during three months of public comment, three public listening sessions, and two dozen one-on-one meetings with agencies and external stakeholder organizations. The purpose of this report was to prioritize the most critical items to integrate into future policies and programs. Third, the Strategic Policy Guide will be a working document from which agencies – and stakeholders – can coalesce around priorities and coordinate action in the years to come.

Clean Transportation and Mobility Innovation Report (2021)

http://climatechange.ri.gov/documents/mwg-clean-trans-innovation-report.pdf

This 2021 report published by the Mobility Innovation Working Group provides a bold and ambitious vision for Rhode Island's transition to a cleaner and healthier transportation network. The scope of the report deals with short-and long-term trends that open opportunities for implementing new technologies and strategies to build a more equitable and environmentally responsible transportation system. The transportation sector represents the largest share of Rhode Island's greenhouse gas emissions. In order to meet a net-zero future, bold initiatives are needed to electrify this sector while also encouraging infrastructure development and community design

Rhode Island's uniquely small land area creates an opportunity to integrate and coordinate transportation and land use policy. The state's single public transit agency, single statewide planning organization, and single major utility have the ability to streamline the framework for GHG emissions reduction policies. Recommendations build off establishing Rhode Island as a national leader in transportation and climate commitments, unlocking economic opportunity and green job creation, while focusing on creating a healthier and more equitable environment for residents of our most overburdened and underserved communities.

Energy Efficiency Market Potential Study (2020)

https://rieermc.ri.gov/resources/

Commissioned in 2020 by the Energy Efficiency and Resource Management Council, this Market Potential Study covers the six-year period from January 1, 2021 to December 31, 2026 and estimates electricity, natural gas, oil, and propane energy savings; passive electric demand reduction savings and active demand response savings; and the costs and benefits associated with these savings.

Value of Forests (2019)

http://www.dem.ri.gov/programs/bnatres/forest/pdf/forest-value.pdf

This 2019 report discusses and identifies ways in which trees, plants, and vegetation are beneficial to Rhode Islanders and the Ocean State as a whole. The study uses data and visual depictions to convey the benefits and impacts of a healthy forest, good management practices, and engaged community members. Furthermore, the study frames areas for improvement and conservation growth with regards to air and water quality, climate change, human well-being, and wildlife. 56% of Rhode Island's land area is covered by vital forests and The Value of Rhode Island Forests focuses on how best to maintain, grow, and understand the state's vast forestry, open space, and conservation land. RIDEM developed this plan in conjunction with the US Forest Service and the Rhode Island Tree Council.

Resilient Rhody (2018) and Resilient Rhody 3-Year Impact Report (2021)

https://riib.org/solutions/initiatives/

To accelerate climate resilience actions and investments, former Governor Gina Raimondo signed an Executive Order on September 15, 2017 calling for the development of the state's first comprehensive climate preparedness strategy. Following nine months of collaborative work, Resilient Rhody was published and it lays the groundwork for collective action, involving state agencies, municipalities, and statewide business, academic, and nonprofit partners. The strategy responds to changing weather and environmental conditions in Rhode Island caused by climate change and proposes bold yet implementable actions to better prepare the state for these impacts. Building on the climate leadership of state government, municipalities, and organizations, Resilient Rhody leverages existing studies and reports to identify critical actions that move Rhode Island from planning to implementation.

Resilient Rhody identified priority actions the state could take to build statewide resilience, as well as a need to work collaboratively with and in support of municipalities across Rhode Island to build resilience at the local level. In response to this need, the Bank, in partnership with The Nature Conservancy, introduced the Municipal Resilience Program (MRP) in order to provide clearer pathways to implement the shared priorities of Resilient Rhody with participating municipalities. The purpose of the Municipal Resilience Program is to help Rhode Island municipalities deepen their understanding of climate risk and adaptation approaches, as well as to assist municipalities to prioritize and implement local resilience actions, effectively increasing climate resilience across Rhode Island and advancing Resilient Rhody. In November 2021, the Bank released the 'Resilient Rhody 3-Year Impact Report' detailing progress that has been made by state agency and municipal partners in turning the original 2018 Resilient Rhody report's recommendations into concrete actions including infrastructure upgrades, coordinated planning, and financing of resilience projects.

Climate Change and Health Resiliency (2015)

https://health.ri.gov/publications/reports/ClimateChangeAndHealthResiliency.pdf

This 2015 report by the Rhode Island Department of Health warrants mention because of its thorough review of climate's impacts on health. The report discusses implications of extreme heat and rising temperatures, air quality, extreme weather, water quality, marine bacteria, and vector-borne disease. Importantly, this report also discusses climate change's implications for mental health. The report provides some next steps for action which continue to be relevant to our recommendations today.

Carbon Pricing Study (2020)

http://www.energy.ri.gov/documents/carbonstudy/final-rhode-island-carbon-price-study-report.pdf

In response to a 2017 directive from the Rhode Island General Assembly, OER and RIDEM in consultation with the RIDOT, contracted with the Cadmus Group and Synapse Energy Economics to investigate potential state and regional carbon pricing policy options to support Rhode Island in achieving the requirements laid out in the 2014 Resilient Rhode Island Act. This report provides an impartial assessment of the implementation considerations and potential impacts of illustrative carbon pricing policies.

The report outlines several key findings: A carbon price at the levels analyzed in this study would not achieve Rhode Island's 2050 greenhouse gas (GHG) reduction targets alone. Determining how to use revenue generated by the carbon price is a chief policy design step. Equity needs to be a conscious choice in both process and ultimate policy design. A carbon price has a small impact on electric vehicle (EV) adoption. A carbon price contributes, in a limited fashion, to increasing the adoption of air source heat pumps (ASHPs). A carbon price will create shifts in Rhode Island's economy, but aggregate economic impacts are expected to be negligible. A carbon price would generally have a limited aggregate impact on households. Lastly, a wider geographic scope would lead to greater success.

Rhode Island Bicycle Mobility Plan (2020)

https://planning.ri.gov/sites/g/files/xkgbur826/files/documents/LRTP/Bicycle-Mobility-Plan.pdf

Approved in December 2020, Rhode Island's Bicycle Mobility Plan (BMP) is the first statewide initiative to expand the bicycle network strategically. The BMP takes a more detailed look at specific conditions, needs, and gaps surrounding bicycle infrastructure and operations in the State of Rhode Island and identifies supporting policies, strategies, and projects that will expand the network over the 20-year vision set out by the Long-Range Transportation Plan. The plan seeks to safely and efficiently connect people and places so that riding a bicycle in Rhode Island is safe and fun for all ages. It also serves as a guide to assist municipalities at developing bicycle infrastructure at the local level.

Rhode Island Transit Master Plan (2020)
www.transitforwardri.com

Also approved in December 2020, the Transit Master Plan (TMP) performs a comprehensive analysis on the condition, needs, and future solutions to the transit network and works within the same 20-year horizon as the Long-Range Transportation Plan and Bicycle Mobility Plan. The TMP sets out to achieve four major goals: make transit attractive and compelling, connect people to life's activities, grow the economy and improve quality of life, and ensure financial and environmental sustainability. The plan hopes to guide investments to provide transit riders with faster services in dedicated lanes, investments in stops and regional hubs, and increased transit frequency.

Clean Energy Industry Reports (2016-2021)
http://www.energy.ri.gov/cleanjobs/

The 2021 Clean Energy Industry Report is the seventh iteration in a series of reports conducted and written by BW Research Partnership, Inc. under commission by the Rhode Island Office of Energy Resources and the Renewable Energy Fund at Commerce RI. Findings in this report are based on data taken from comprehensive 2021 U.S. Energy and Employment Report (USEER). The 2021 USEER utilizes data from the Bureau of Labor Statistics Quarterly Census of Employment and Wages (BLS QCEW 2019 Q2) and Current Employment Statistics, as well as survey data. The survey was designed and implemented by BW Research Partnership. This series of reports provide crucial insight into trends in Rhode Island's clean energy workforce.

Select New Programs Since 2016
This section highlights some programs that have supported decarbonization strategies in Rhode Island, focusing on new programs since the *2016 Greenhouse Gas Emissions Reduction Plan* was released. The main takeaway from the programs described below is that we have gained a lot of experience with offering programs to support decarbonization. This experience should be leveraged to support progress toward our 2030 mandate and these programs provide an existing vehicle for deploying funding to support our climate goals.

This is not a comprehensive inventory of programs – to keep this section manageable, we exclude many impactful programs that began prior to 2016, are limited in term and funded by external grants, or are not administered directly by state agencies. We also omit many significant refinements to existing programs that have increased their impacts and benefited Rhode Islanders.

Expanding Energy Efficiency Programs
While National Grid (now RI Energy) has a long history of administering an energy efficiency program for its customers, Rhode Island's two municipal-owned utilities have made notable advances in their own energy efficiency programs. Since 2016, we can now say we have full statewide coverage to support energy efficiency.

Following an initial pilot program in 2015-2016, Block Island customers were offered an expanded energy efficiency pilot program called 'Block Island Saves' in 2016-2017. In 2021, Block Island Utility District launched a full-scale energy efficiency program for its customers.

Electric customers in Pascoag saw their long-running program substantially expanded beginning in 2019. The new program offers more incentives for more types of energy efficiency upgrades for both households and businesses.

Renewable Energy Fund

CommerceRI's Renewable Energy Fund (REF) provides grants for renewable energy projects. Since the program started in 2014, nearly 500 applicants received Renewable Energy Fund grants totaling $3.7 million for over 11 MW of grid-connected renewable energy.[43] Several notable program features have been added to the Renewable Energy Fund since 2016.

In 2017, the REF began incentivizing Community Renewables, including community solar. A community solar project is a large solar farm shared by more than one household. Its primary purpose is to allow members of a community the opportunity to share the benefits of solar power even if they cannot install solar panels on their roof or property.

In 2020, the REF began incentivizing the installation of solar projects located on brownfields. Brownfields are former industrial or commercial sites where future use is affected by environmental contamination and are often ideal locations for renewable energy projects. By incentivizing the installation of solar on already disturbed sites, this feature helps reduce pressures to develop open space, forests or farmland for solar projects.

In 2020, the REF began piloting an enhanced incentive for solar projects that are paired with battery energy storage systems. Energy storage can help match the timing of renewable electricity production with that electricity is consumed, which can reduce strain on our electric grid during critical times and provide other grid support. Energy storage can also provide backup power when the power is out.

Supply Chain Challenges

> *Supply Chain Shortages due to COVID-19 have had dramatic impacts on construction costs for clean energy systems. Spikes in steel prices, other raw materials, and transportation costs have led to higher costs and delays for renewable energy systems, electric transportation, and electric heat pumps. Rising costs and supply chain issues continue to create uncertainties in the clean energy industry, especially with respect to the reliability of future employment opportunities given the ongoing pandemic.*

Electric Transportation Programs

Since 2016, Rhode Island has offered several new programs to support electric transportation.[44] From 2016-2017, incentives for electric vehicles were available through a program called DRIVE. This program offered rebates up to $2,500, based upon vehicle battery capacity. Over 250 Rhode Island drivers received rebates, totaling the programs funding limit of $575,000. Electric vehicles using the DRIVE

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[43] Data through 12/31/2021

[44] This section does include programs offered by third parties or federal agencies, but we recognize the importance of these programs.

incentive were purchased at 15 different car dealerships across Rhode Island, generating over $300,000 in sales tax revenue for the state.

From 2017 to 2019, the Office of Energy Resources supported the installation of electric vehicle charging infrastructure at public locations through the ChargeUp! program. This program provided applicants with incentives to support the purchase and installation of electric vehicle charging stations (Level 2 or higher) at publicly accessible locations. In addition, applicants that installed at least one charging station through this program could also qualify for incentives to support the purchase or lease of a new electric vehicle as part of their public sector fleet. ChargeUp! supported the installation of 49 dual charging stations and the purchase of 9 electric vehicles.

From 2019-2022, the Office of Energy Resources ran an incentive program for electric vehicle charging stations called Electrify RI, funding with $1.4 million from the Volkswagen Diesel Settlement[45]. Incentives varied from $10,000 to $40,000 based on the type of charging station (Level 2, or DCFC) and sector (workplaces, multi-unit dwellings, state and local government, and publicly accessible locations). As of November 30, 2022, Electrify RI has supported the installation of 70 Level II charging stations, and 23 DC Fast Chargers throughout Rhode Island. In 2022, further federal funding will be available to expand electric vehicle charging infrastructure.

In July 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) and e-Bike rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program. It works towards making EVs more affordable for more Rhode Islanders.

Following recommendations from the 2017 Power Sector Transformation report, National Grid began its Electric Transportation Initiative. This suite of programs includes a pilot to encourage charging at certain times of the day to reduce strain on the electric grid, an incentive program to offset some costs of installing electric vehicle charging stations, and technical assistance to support converting fleets from gas to electric.[46]

Incentives for Heat Pumps

Converting heating systems to electric heat pumps is a key strategy to reduce emissions from heating. Incentives for installing heat pumps are new since 2016. These incentives have been offered by utility energy efficiency programs and by the Office of Energy Resources leveraging auction proceeds from the Regional Greenhouse Gas Initiative (RGGI). Since 2016, incentives have supported hundreds of households – in 2021 alone, over 500 households were supported. In 2022, the General Assembly passed a budget article that allocated $25 million to the High-efficiency Heat Pump Program (HHPP) that will provide a broadened suite of heat pump incentives to Rhode Islanders. It is set to launch in early 2023.

Agricultural Energy Grant Program

The Rhode Island Department of Environmental Management and Office of Energy Resources partnered to offer an energy grant program specifically designed to support farmers. The Agricultural Energy Grant Program provides grant awards of up to $20,000 for eligible energy efficiency and renewable energy

[45] https://dem.ri.gov/environmental-protection-bureau/air-resources/mobile-sources/volkswagen-settlement
[46] The Electric Transportation Initiative also included a discount on demand charged for eligible customers installing fast charging; this discount is no longer offered.

projects at qualifying Rhode Island Farms. This funding helps local farmers "green" their operations and benefit from the related energy and cost savings through energy efficiency projects and by transitioning to renewable power. Funding for this program is made possible through the Regional Greenhouse Gas Initiative (RGGI). Since 2016, grants totaling over $894,000 have supported more than 50 projects.

Lead-by-Example

Signed in 2015, Executive Order 15-17 set forth specific goals for the State Administration to lead-by-example. Since then, the Office of Energy Resources has devoted staff resources to leading this body of work and has expanded support to other public entities. To tout progress being made, the Lead-by-Example Annual Awards recognize achievement of public sector entities in implementing clean energy projects.

Since 2016, several Master Price Agreements (MPAs) have been developed to streamline procurement processes for state agencies and other public entities. An MPA is a list of pre-qualified vendors from whom a procurer may solicit quotes. This purchasing mechanism expedites decarbonization by clearly defining proposal requisition processes and providing access to a pool of prequalified energy services vendors. MPA 508 includes vendors to develop and install turnkey energy efficiency projects. MPA 509 includes vendors to develop and install electric vehicle charging stations. MPA 553/CR 44[47] includes firms that can provide turnkey solar installation and maintenance services for public entities.

OER has also coordinated several competitive procurements of gas and electricity supply. These procurements, in addition to covering all State accounts, have also been made available to other public sector entities, such as quasi-state agencies and municipalities. By aggregating demand and leveraging economies of scale through a competitive process, OER and the Department of Administration aim to reduce energy supply costs and reduce energy price volatility for all participating public entities. The current electric contract will deliver approximately $2.3 million in bill savings in 2021 compared to the default utility price and the current gas contract will deliver approximately $2.1 million in bill savings in 2020 compared to the default utility price.

OER is now the central clearinghouse for all utility billing for State accounts. By collating and providing greater oversight over State agency utility bills, OER has been able to improve energy usage and cost forecasting, decrease payment errors, and analyze progress toward Lead by Example goals. Importantly, OER has been simultaneously working to increase public and inter-governmental transparency into these important data sets.

In February 2018, Rhode Island’s first voluntary Stretch Codes were made available to private and public building construction and renovation projects. The codes were developed with the assistance of subject matter experts and were vetted through a public comment process. Rhode Island’s Stretch Codes are meant to be used on a voluntary basis to guide the construction and/or renovation of buildings that use less energy, have less negative impact on the environment, and achieve higher levels of occupant health and comfort.

In 2021, the LED School Lighting Accelerator Pilot was launched to support the conversion of public-school facilities to LEDs in Central Falls and Providence. Public schools, particularly in economically challenged school districts, have not had the funding and technical expertise to implement many clean energy upgrades. By providing the technical, procurement, and financial support needed to implement these projects, OER is helping to improve the operations, efficiency and learning environment in public

[47] CR-44 is a Continuous Recruitment procurement list. Similar to an MPA, a CR is a list of pre-qualified vendors. In contrast to an MPA, a vendor may apply to be included on a CR at any time through an open enrollment process.

school facilities. After a successful pilot, OER scaled up efforts to support LED lighting projects in additional districts, expanding the reach of the program to 10 communities by the end of 2022.

Created in 2019, the Clean Energy Internship Program is designed to help provide internship opportunities in clean energy careers, ranging across sectors (e.g. energy efficiency, solar) and job types (e.g. direct construction, engineering, research). This programs pairs students with host companies from Rhode Island. Student interns can develop professional skills under the mentorship of an industry partner to combat real world problems in energy and the environment. The Clean Energy Summer Internship program approved five interns providing a reimbursement to four clean energy host companies that totaled $16,871.85 in calendar year 2021.

Municipal Resilience

Resilient Rhody identified priority actions the state could take to build statewide resilience, as well as a need to work collaboratively with and in support of municipalities across Rhode Island to build resilience at the local level. In response to this need, the Bank, in partnership with The Nature Conservancy, introduced the Municipal Resilience Program (MRP) in 2019 to provide clearer pathways to implement the shared priorities of Resilient Rhody with participating municipalities. The purpose of the MRP is to help Rhode Island municipalities deepen their understanding of climate risk and adaptation approaches, as well as to assist municipalities to prioritize and implement local resilience actions, effectively increasing climate resilience across Rhode Island and advancing Resilient Rhody.

As of 2022, 27 municipalities have participated in the Rhode Island Infrastructure Bank's program which includes a robust stakeholder engagement approach to resilience planning. MRP workshops have hosted over 600+ participants, including municipal staff and community leaders. 350+ potential resilience capital projects have been identified using this locally specialized approach.

As of 2022, 46 resilience projects have been funded through MRP Action Grants - a total of $7.5 million in assistance. 93% of MRP Action Grants have incorporated green infrastructure and/or nature-based solutions. $7 million was allocated to the MRP through the 2021 Beach, Clean Water, and Green Economy Bond, and another $16 million was allocated to the MRP through the 2022 Green Economy Bond. MRP workshops statewide have identified a need for local capacity building, as well as a need for regional approaches that can address resilience projects spanning municipal boundaries. Rhode Island Infrastructure Bank launched a pilot Regional Resilience Coordinator position at the Bank, within the MRP, to provide additional capacity for local resilience. The pilot position, a Regional Resilience Coordinator for Aquidneck Island, assists island municipalities to advance intra- and inter-municipal resilience efforts, and serves as a model for future Regional Resilience Coordinator positions at the Bank.

MRP municipalities have also expressed a need for increased design and engineering assistance, particularly for resilience projects implementing green infrastructure and nature-based solutions. In response, the Bank will launch a new initiative in 2023: '*Creating a Centralized Nature-Based Resilience Program for RI*.' This upcoming initiative, funded by the National Fish and Wildlife Foundation and conducted by the Rhode Island Infrastructure Bank in partnership with Narragansett Bay National Estuarine Research Reserve, University of Rhode Island Coastal Resources Center / Sea Grant, Save the Bay, and The Nature Conservancy, will assist MRP municipalities to advance resilience project ideas to construction ready designs.

Climate Change and Health Program

Since the 2015 Climate Change and Health Resiliency report, RIDOH has continued to support community resilience and adaptation efforts focusing on extreme heat, flooding, emergency preparedness, and sea level rise. Resilience building efforts with the Health Equity Zones have resulted in grants for urban greening and tree planting, community education and youth activities, and efforts to support senior living facilities, schools, and municipal cooling centers.

During the summer of 2020, RIDOH collaborated with the RIDEM Division of Forest Environment and American Forests to measure ambient air temperatures across several Rhode Island municipalities and neighborhoods. This project resulted in a set of maps that identifies urban heat islands and heat disparities during different times of the day. Areas where overnight temperatures stay high and where daytime temperatures can be up to 12 degrees hotter than others are considered priority areas for heat mitigation using tree planting and other urban greening techniques.

In 2021, the RIDOH Climate Change and Health Program conducted a needs assessment with a small group of stakeholders. This assessment showed that we need to continue collaborating across state agencies to deepen our connection with the community and drive change through inclusion of a diversity of community voices. The Climate Change and Health Program sees its role as supporting community engagement, educating the public and other agencies about risks to human health, and building resilience and social cohesion. Additional resources are needed to continue this work at a meaningful level while integrating it into 2021 Act on Climate goals.

Climate & Youth

> *Climate change has contributed to extreme weather events, air pollution, and rising temperatures. As the impacts of climate change become more severe, the fear of uncertainty in our future grows. Our youth population is already facing challenges caused by climate change. We need to prepare and educate our youth on how policies can be used to regulate and slow down the anthropogenic activities that are causing climate change. This will allow the future generation to gain skills that will help them determine the best ways to fight against climate change. When it comes to youth and climate it is also important to recognize that young people are active participants in climate action and provide a valuable perspective that deserves to be heard by decision-makers, as we will be leaving the Earth to them.*
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> *Climate change education is critical because the impacts that climate change is having on humans goes beyond our physical health. It can also affect our mental health, especially in our youth. For example, natural disasters related to climate change, such as hurricanes and wildfires, may lead to high levels of anxiety and trauma. Long-term impacts of climate change can cause fear of not knowing what the future of our environment will be, leaving our youth feeling helpless. To help ease the anxieties of climate change in our youth, we need to educate them on the importance of climate policies and what they can do personally to help.*
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> *It is important that we ensure our youths voices are heard. Through climate-youth workshops, young Rhode Islanders can learn about our current climate change policies as well as be given an opportunity to share their ideas on climate's impact on our youth. It is critical that we focus not only on meeting our climate mandates but also ensuring health, safety, and comfort of our youth community.*

Policies and Legislation

The following list highlights some policies and legislation that showcase substantial commitments toward our climate goals. This list is not exhaustive, and every piece of policy and legislation matters. Interested readers should contact their local legislators to learn more about considerations in the General Assembly.

2021 Act on Climate

The 2021 Act on Climate sets statewide, economy-wide climate goals that are both mandatory and enforceable. The Act requires the state reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and reach net-zero emissions by 2050. The Act also requires the development of this update to the *2016 Greenhouse Gas Emissions Reduction Plan* in 2022 and a comprehensive climate strategy by 2025, to be updated every five years thereafter.

Critically, the Act deems addressing the impacts on climate change to be within the powers, duties, and obligations of all state departments, agencies, commissions, councils, and instrumentalities, including quasi-public agencies. The Act gives each agency the authority to promulgate rules and regulations necessary to meet the Act's greenhouse gas emissions reduction mandates.

COP26 (Signaling Promising Momentum) and COP27 (Loss & Damage Fund)

In November 2021, the United Nations Climate Change Conference (called COP26) was held in Glasgow, Scotland. Many first-hand accounts of this remarkable meeting were shared afterwards, including from Rhode Island State Senator Dawn Euer at the December meeting of Rhode Island's Executive Climate Change Coordinating Council held in Newport.

Bill Gates also shared his experiences and observations in a blog post. Mr. Gates noted three major areas of change that have happened since the last summit he attended in 2015; clean-energy innovation is higher on everyone's agenda, the private sector is now playing a major role alongside government agencies; and, there is much more public visibility and acceptance of climate adaptation.

The 27th Conference of the Parties (COP27) took place during the first two weeks of November 2022 in the Egyptian coastal city of Sharm el-Sheikh. More commonly referred to as COP27, this conference was touted as the "Africa COP" with a specific focus on implementation to help turn past pledges into real climate action. The conference closed on November 20th after all night negotiations. The highlight of the conference was an agreement to establish a "loss and damage" fund. The fund aims to provide financial assistance to nations most vulnerable to the adverse effects of climate change. However, key details, such as which countries will pay into the fund, have yet to be fully decided. While the creation of a "loss and damage" fund was historic, the lack of action on adaption and mitigation begs the question of whether the "loss and damage" fund will translate into action. Additionally, many countries did not bring updated nationally determined contributions to COP27 and therefore have not set more ambitious climate targets that are necessary to stay below the Paris Agreement goal of a 1.5°C. Finally, the most disappointing element of COP27 was the failure to commit to decisively phase out the use of fossil fuels.

Appliance Energy Efficiency Standards

In 2021, the General Assembly updated Rhode Island's energy and water efficiency standards for a number of common appliances.[48] The legislation sets minimum efficiency standards for 15 household and commercial products which will save energy, save money, and reduce greenhouse gas emissions. From 2023 to 2035, these standards are expected to reduce emissions by 256,000 metric tons.

Transportation and Climate Initiative

The Rhode Island Department of Environmental Management led Rhode Island's participation in the Transportation and Climate Initiative (TCI), a regional cap-and-invest policy proposal for the transportation sector. In December 2021, neighboring states Connecticut and Massachusetts paused their participation in this effort. As this effort depends upon the involvement of at least three jurisdictions, Rhode Island cannot move forward with TCI at this time. However, key insights about priorities for program design and revenue investment should be incorporated into future policies and programs.

Conversations about Solar Siting

Since 2016, increasing deployment of large solar PV systems in forested areas has raised concerns from stakeholders and the public about finding the right balance of renewable energy development amidst policy objectives like decarbonization and land conservation. These local conversations have informed studies (e.g. the Solar Siting Opportunities study, Value of Forests report), program design (e.g. REF Brownfields Program), and policies (e.g. municipal solar ordinances). These conversations should continue to inform our climate strategies, particularly related to decarbonizing our electric sector and preserving environmental benefits of Rhode Island's forests.

Increasing Biofuels

In 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil. The new law requires home heating oil to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025 and 50% in 2030. Biodiesel is a fuel made from plant or animal products or waste. It must meet standards and is blended with petroleum heating oil to burn cleaner and reduce greenhouse gas emissions. Rhode Island had previously required heating oil to be sold as a mix that contains 5 percent biodiesel, phased in between 2014 and 2017.

Offshore Wind

In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. This new project is expected to reduce Rhode Island's greenhouse gas emissions by 11 MMTCO2e, in addition to providing substantial local economic benefits including more than 800 direct construction jobs, 50 permanent jobs, and hundreds more jobs supported indirectly as the region's burgeoning offshore wind industry takes off.

Land and Forest Conservation

In 2016, the RI General Assembly amended the laws of the state as they relate to the conservation and preservation restrictions on real property (RIGL §34-39-5). The amendment makes it more difficult remove land conservation restrictions. The result has been stronger land protection laws in Rhode Island.

Forests provide invaluable ecosystem services like carbon sequestration and storage that are essential to meeting the state's climate change goals. In recognition of this natural asset, the Rhode Island General

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[48] RIGL 39-27.1 Appliance and Equipment Energy and Water Efficiency Standards Act of 2021

Assembly passed the Forest Conservation Act in July 2021 (RIGL §2-27). The Act establishes a Forest Conservation Commission (FCC) to inventory the state's forestland, develop stronger tools and incentives for forest conservation, expand urban and community forestry, and grow the state's forest products industry. Led by RIDEM, the Forest Conservation Commission has been meeting regularly since mid-2022.

Pressures on Land Conservation Efforts

Land conservation efforts are significantly impacted by real estate market dynamics. Rhode Island's housing market has seen an unprecedented increase in value over the past several years. However, higher than ever development costs (i.e., roads, utilities, and home construction) have led to uneven expectations for the value of large land parcels, often leaving state land protection programs unable to match private market offers. Similarly, pressure for kilowatts of solar (renewable) energy has resulted a in large tracts of undeveloped property being converted to fields of solar panels. Finding the right balance between solar development and the need to protect working farms and forest land continues to be the subject of much discussion at the local level and in the General Assembly. Siting guidance and incentives that push solar development away from large forested and agricultural parcels can help to protect Rhode Island's remaining open space.

It is an ongoing challenge to protect interconnected land areas of sufficient size to support wildlife, biodiversity, and ecosystem services for future Rhode Island generations. Large, interconnected conservation lands are particularly important as a strategy for adapting to climate change because the distribution of animals and plants are likely to shift and continue shifting as temperatures, rainfall and the timing of seasons continue to morph over coming decades. Ensuring the state can be ready to match available funding with the opportunity to protect such critical land resources should be a priority resilience measure.

Rhode Island's 400 miles of coastline is particularly vulnerable to episodic storms, erosion, coastal flooding, inundation and storm surge. The National Oceanic and Atmospheric Administration's February 2022 report 'Global and Regional Sea Level Rise Scenarios for the United States' indicates that relative sea level along the contiguous US coastline is expected to rise on average as much over the next 30 years as it has over the last 100 years. Land conservation efforts that accommodate and proactively target areas to allow for the inland movement of coastal habitat, such as wetland migration, are increasingly being considered to help maintain natural storm surge buffers, wildlife habitat, wetland-dependent human activities, water filtration, and other ecosystem services coastal wetlands provide.

2021 Beach, Clean Water, and Green Economy Bond & 2022 Green Bond

The 2021 Beach, Clean Water, and Green Economy Bond dedicated $7 million to the Municipal Resilience Program matching grants to municipalities to restore and/or improve the resiliency of infrastructure, vulnerable coastal habitats, river and stream floodplains, and watersheds. The Bond passed with 78.3% support, allowing the Municipal Resilience program funds to further advance community resilience to the impacts of climate change.

In the pilot years of the Municipal Resilience Program, limited MRP Action Grant funds meant that the Bank could only offer Action Grants to municipalities who had completed their MRP workshop in the current award year. With the support of this State Green Bond, the Bank has been able to expand the call for MRP Action Grant proposals, allowing any community who completed a Municipal Resilience Program workshop in any year access to MRP Action Grant funds annually. With a successfully widened call for MRP Action Grant proposals in fall of 2021, the Bank seeks to continue offering annual MRP Action Grants to all MRP municipalities each year.

2022 saw the passage of the 2022 Green Bond which infused an additional $16 million into the Municipal Resilience Program. This has greatly increased the capacity of the Bank to support resilience priorities identified by a majority of communities across Rhode Island.

Progress on 2016 Pathways

The *2016 Greenhouse Gas Emissions Reduction Plan* organized its emissions mitigation strategies as a set of pathways under three overarching objectives: build on state success, enable markets and communities, and leverage regional collaboration. We refer the reader to the 2016 Plan for the full description of each of these pathways. Here, we summarize the progress since 2016 and comment on the progress we still need to make. For additional detail on specific items since 2016, we refer readers to the other sections within this chapter.

Build on State Success

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that "Rhode Island has existing policies and proven models to address nearly all mitigation options, creating a strong foundation the State can build upon to reach our goals." Since 2016, Rhode Island has continued to be a leader in our climate efforts.

Energy Efficiency

Rhode Island has continued to invest in its energy efficiency programs. In 2021, the General Assembly extended the statutory obligation to offer energy efficiency through 2029.[49] Programs have also been initiated and enhanced for customers of Pascoag Utility District and Block Island Utility District.

One notable achievement of these energy efficiency programs is their influence on transforming the lighting market. Programs in previous years emphasized incentives that reduced the customer cost of energy efficient lighting, a very cost-effective low hanging fruit to reduce energy use. Thanks to these incentives and appliance efficiency standards, energy efficient LEDs are now the prominent type of lighting technology, rendering utility incentives for LEDs unnecessary in most applications. Today's energy efficiency programs are in the transition to incentivize other efficient technologies like building automation, high-efficiency HVAC, and weatherization.

The 2016 Plan recommends "policymakers could address a critical gap in existing programs – limited energy efficiency services for delivered fuels (heating oil and propane) customers, a group comprising over one-third of all heating customers. A sustainable funding and/or financing solution is needed for these users to enjoy full and equal access to energy efficiency programs." Rhode Island continues to lack this sustainable funding solution for customers relying on delivered fuels for heating.[50] Short-term, limited funding has been proposed as a stop-gap solution, but we must come up with a permanent funding stream to achieve the level of heating decarbonization needed to meet our longer-term climate mandates.

[49] Least-Cost Procurement Statute

[50] Some funding is available to incentivize some efficiency measures for electric customers who heat with delivered fuels (e.g. weatherization).

The 2016 Plan recommends screening additional appliances to see whether enacting or updating energy efficiency standards may be warranted – in 2021, Rhode Island did indeed enact updated appliance efficiency standards.[51]

Lastly, the 2016 Plan recommends making energy costs of purchases visible to consumers including through building energy disclosure and labeling. While discussions have occurred, no such statewide policy has been enacted.

Vehicle Miles Traveled (VMT) Reductions

The 2016 Plan notes a number of considerations that may encourage the reduction of vehicle miles traveled, including increasing transit and mode share ridership targets, integrating transportation and land use planning, using price signals to discourage solo driving, and investing in alternative modes of mobility.

In 2019, Rhode Island launched the Mobility Innovation Working Group, a 26-member panel of experts comprised of equal participation from the private and non-profit sectors as well as key state agency representatives. The two-year effort culminated in a thorough strategy for improving mobility broadly, including additional thinking around reducing vehicle miles traveled. To date, there has been no concerted action to expressly reduce vehicle miles traveled. On the contrary, all efforts have been based on strategies to improve the relative attractiveness (e.g. convenience, cost savings) of alternative forms of mobility (e.g. transit, biking, walking) and better connect residents with destinations (e.g. state and local comprehensive plans).

In 2021, the Rhode Island Turnpike and Bridge Authority completed installation of all-electronic tolling at their Jamestown Plaza serving drivers crossing the Newport Pell Bridge. While not explicitly reducing vehicle miles traveled, this project does reduce idling and congestion, which reduces localized air pollution and emissions.

Clean Energy

The 2016 Plan recommends aligning "in-state renewable energy policy and deployment targets to be consistent with the broader goal of a 99% clean regional grid by 2050. As part of this consideration, policymakers would need to weigh the comparative costs and benefits of different pathways (e.g., local versus regional renewables, the role of different technologies, and the need for incremental distribution or transmission investments)." Rhode Island's 100% Renewable Electricity by 2030 report analyzes the trade-offs between various technology pathways to meet all of Rhode Island's electricity demand with renewable energy resources. Among other important insights, this report recommends enacting an accounting mechanism to ensure Rhode Island either generates or offsets all its electricity consumption with renewable energy resources.

Electric Heat

The *2016 Plan* noted the importance of transitioning to energy efficient electric heat, and the 2021 Act on Climate's stronger emissions mandates will necessitate this strategy even more. To offset costs of transitioning to efficient electric heating, the *2016 Plan* suggests using existing energy efficiency programs which would require "further policy guidance is needed to allow electrification of heating to fully qualify as an activity under the State's energy efficiency program or another energy program." Regardless of programmatic avenue to deploy funding and assistance, sustainable funding is needed.

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[51] RIGL 39-27.1 Appliance and Equipment Energy and Water Efficiency Standards Act of 2021

While there is a long-term funding source identified for upgrading inefficient electric heating systems (e.g. electric resistance) to efficient electric heating (e.g. heat pumps), this is not the case for supporting customers who would like to switch fuels. We have since employed short-term and limited funding sources as a stop gap measure to support fuel switching. Rhode Island has not yet identified a long-term source of funding that can support energy efficient heating electrification, particularly for customers who currently rely on delivered fuels, within our current statutory framework.

Biofuel Heat

In line with recommendations from the *2016 Plan* to increase the existing statewide bioblend standard, the General Assembly updated the Biodiesel Heating Oil Act in 2021. The strengthened Act now requires all home heating oil sold in Rhode Island to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025, and 50% in 2030.

Electric Vehicles

The *2016 Plan* recommends "further initiatives to incentivize the adoption of electric vehicles and charging infrastructure would be needed to achieve the aggressive market penetration levels necessary to meet long-term GHG reduction targets." Accordingly, Rhode Island has deployed several incentive and assistance programs to support electric vehicle purchases and installation of charging infrastructure, with significant incentive programs and funding becoming available in 2022.

In line with recommendations, the Rhode Island Public Transit Authority is working to convert its entire fleet to electric or zero-emissions buses by developing an action plan and the Department of Transportation is conducting a study to understand implications for gas tax revenues and resulting policy considerations to ensure sustainable funding for our transportation infrastructure. These commitments, along with many others by all state agencies represented on the Executive Climate Change Coordinating Council, are described in the report Electrifying Transportation.

The *2016 Plan* also recommends "future planning for the state's passenger and freight rail transportation system could also evaluate electrification as a strategy aligned with long-term greenhouse gas reduction targets." Electrification continues to be discussed and is considered in Transit Forward 2040, a collaboration between the Rhode Island Public Transit Authority, the Rhode Island Department of Transportation, and the Rhode Island Division of Statewide Planning.

Rhode Island has previously adopted California's emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California's standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles. Rhode Island should continue to adopt new rules, including California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers, as well as the Advanced Clean Cars II regulation.

Transportation Biofuels

The *2016 Plan* suggests "Rhode Island could explore the feasibility of establishing a statewide bioblend standard" similar to bioblending for heating oil. Such a standard has not been enacted to date.

Land Use Conservation

The *2016 Plan* suggests considering "adoption of a 'no net-loss of forests' policy." While such a policy has not be enacted per se, recent policies have strengthened land and forest conservation (RIGL §34-39-5 and RIGL §2-27). Renewable energy programs have also been developed to nudge renewable energy development away from forested areas and onto previously disturbed sites.

Natural Gas Leaks

The *2016 Plan* recommends "continuation of National Grid's gas infrastructure repair and replacement program to address fugitive methane leaks in the state's gas distribution system." Indeed, this work has continued in collaboration with the Division of Public Utilities and Carriers and under the regulatory oversight of the Public Utilities Commission.[52] Approximately 500 miles of leak prone pipe has been replaced since 2016 –which reduces leaks from the pipeline gas system. However, leak prone pipe replacement may actually be counterproductive to meeting the Act on Climate, since pipes that are replaced have a 50–100-year lifespan. This topic will likely be analyzed the Public Utility Commission's upcoming Future of Gas docket.

Energy Storage

The *2016 Plan* recommends "pursuit of policies to promote energy storage, which can provide many types of system benefits, including integrating clean energy resources in a more cost-effective manner." Since 2016, two key programs have been deployed to encourage energy storage: payment for performance of energy storage systems during demand response events and incremental incentives for solar PV systems paired with energy storage. The report 100% Renewable Electricity by 2030 echoes the recommendation to build out a strategic role for energy storage as we increase renewable energy on our regional grid; this work has not yet begun. In addition to electric energy storage, there are thermal storage options that can help decarbonize the thermal sector. These have not yet been extensively explored, but should evaluated in the coming years.

Other

This section outlines three 'other' pathways described in the *2016 Greenhouse Gas Emissions Reduction Plan*. In addition to the updates below, in 2021, RIDEM also enacted a new Air Pollution Control Regulation to prohibit manufacturers from selling products (air conditioning and refrigeration equipment, aerosol propellants, and foam) that contain a certain particularly potent greenhouse gas.[53]

Battery Storage in Pascoag

The Pascoag Utility District (PUD) unveiled a new 3MW/9MWh stand-alone battery storage installation in August of 2022, which will provide needed grid-reliability and peak load reductions for the utility's 5,000 customers. This battery project, alongside a needed substation upgrade, helped PUD avoid nearly $12 million dollars in infrastructure investment that would have otherwise been required to continue reliably serving their customers during peak-load conditions in the summer months.

Through an innovative and collaborative partnership with the Office of Energy Resources, the Rhode Island Infrastructure Bank, and Agilitas Energy, PUD was able to provide the reliability and load management it needed, at a fraction of the cost to its customers. The implementation of this battery is a successful example of implementing a non-wires alternative to improve reliability at a lower cost.

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[52] Plans for identifying and prioritizing the replacement of 'leak-prone pipe' are proposed in annual Infrastructure, Safety, and Reliability Plans. The most recent plan is included in Docket 5210.

[53] Part 53 of the Air Pollution Control Regulation, "Prohibition of Hydrofluorocarbons in Specific End Uses" (250-RICR-120-05-53) prohibits manufacturers from selling products that contain high global warming potential hydrofluorocarbons.

A first of its kind project in Rhode Island, this stand-alone battery demonstrates the viability of storage technologies in not only delivering value for utility customers but also supporting the State's Act on Climate mandates to reduce GHG emissions. Using batteries to store energy and dispatch it later at times of peak demand helps balance supply and demand. It also supports the transition to clean energy by allowing better integration of the increasing amount of renewable energy coming onto the electric grid.

Solid Waste

The *2016 Plan* recommends we put in place "strategies to reduce methane emissions from the Central Landfill." The RI Resource Recovery Corporation (RIRRC) continues to maintain a landfill gas (LFG) recovery system at the Central Landfill. LFG, which contains methane, is captured, converted, and used as a renewable energy resource. Using LFG helps to reduce odors and prevents methane from migrating into the atmosphere and directly contributing to climate change. Rhode Island's Central Landfill has one of the largest methane-to-energy plants in the country.

In 2015, RIRRC completed a waste characterization study that highlighted a significant opportunity to extend the life of its Central Landfill by further diverting organics from the municipal residential waste stream. Anaerobic decomposition of organic materials in landfills produces methane, a greenhouse gas with global warming potential many times higher than carbon dioxide. In 2018, RIRRC's Long Term Solid Waste Alternatives Study subsequently identified several means for processing this material. Then, in 2019, RIRRC identified 13 potentially viable collection scenarios that could be pursued for the technologies short-listed in the 2018 Alternatives Study. Recognizing that collection costs are a significant consideration of overall program delivery, RIRRC issued a request for proposals in 2020 to better understand the collection scenarios for organics that could be pursued in Rhode Island and what their associated costs may be – results of this analysis are expected in 2022. The co-benefit of reducing organics in the Central Landfill as a means to extend the life of the Central Landfill will be reduced methane emissions.

Enable Markets and Communities

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that "Rhode Island's best resources are our people and communities – with the right support, we can remove barriers to clean energy market growth, consumer education and engagement, partnership of utilities, and public sector leadership." This strategy of partnership and collaboration has not only been foundational for Rhode Island's leadership but has improved since 2016.

Grow Clean Economy Jobs

The *2016 Plan* provide three recommendations for state policymakers: "fostering nascent local clean energy industries, supporting innovation in clean energy, providing workforce training, and assisting incumbent fossil fuel industries (e.g., the delivered fuels industry) and disadvantaged communities with resources to excel in the burgeoning clean energy marketplace."

We point readers to the Office of Energy Resources annual Clean Energy Industry Report for more details about job growth and industry trends but note a few key items here. First, Rhode Island is working hard to position itself as a hub for the domestic offshore wind supply chain. For example, the 2019 contract for the 400 MW Revolution Wind offshore wind project includes $4.5 million in investments for Rhode Island's ports and offshore wind workforce.[54] Second, Rhode Island continues to support the local solar industry through programs that incentivize solar (e.g. RE Growth Program, Renewable Energy Fund) and partnerships for workforce development (e.g. Clean Energy Internship Program). Third, in 2022 the Department of Labor and Training is beginning an industry convening to assess workforce development needs for increasing consumer adoption of electric transportation (to launch in 2023). Fourth, the High-efficiency Heat Pump Program (HHPP) includes supporting workforce development as a key component.

Further strategic analysis needs to be conducted to recommend specific action items needed to support a just transition with living wages as part of the development of the *2025 Climate Strategy*, as required by the 2021 Act on Climate.

Empower Citizens and Communities

The *2016 Plan* lists barriers to consumer adoption of decarbonized technologies: "low customer awareness and confidence in previously unfamiliar products; access to and availability of financing solutions; soft costs related to permitting and regulatory hurdles; technical assistance for municipalities to implement solutions." These barriers are still present, but some work has attempted to mitigate them. This work includes consumer education and outreach campaigns (e.g. via Ocean State Clean Cities Coalition, via the Energy Efficiency and Resources Management Council), financing through energy efficiency programs and the Rhode Island Infrastructure Bank (e.g. HEAT Loan, on-bill repayment, Efficient Buildings Fund), and technical support for municipalities (e.g. via the Municipal Resilience Program, via OER's Shared Energy Manager pilot program). However, gaps remain and barriers are still present, which necessitates continued work to empower citizens and communities, and particularly low-income and vulnerable communities.

Foster a More Dynamic Regulatory Model

The *2016 Plan* states "state policymakers and utility regulators will continue initial efforts already underway to consider thoughtful changes to utility planning, business models, performance incentives, and rate design in order to enable a transition to the future grid that values, integrates, and plans for growth in clean energy and carbon-free resources, while maintaining a safe and reliable electric system." This statement alluded to the Power Sector Transformation initiative, which resulted in a stakeholder

[54] Press Release from April 2019

report in 2017. Resulting recommendations led to National Grid's programs related to electric transportation and proposals for both modernizing our electric grid and deploying advanced metering infrastructure. While these two proposals were filed in 2021, they were on hold while other regulatory proceedings were being resolved. In November 2022 Rhode Island Energy filed their Advanced Metering Functionality (AMF) Business Case to the Public Utilities Commission.[55] The Power Sector Transformation report also includes a number of recommendations that should continue to be considered.

Lead-by-Example

The *2016 Plan* advocates for the "state government to serve as an early adopter to demonstrate the benefits of greenhouse gas mitigation and clean energy solutions." In accordance with this recommendation, the Office of Energy Resources has supported state agencies across government leading by example with reducing energy use and cost, deploying renewable energy systems, transitioning fleets to electric, and installing electric vehicle charging infrastructure, among other accomplishments. These efforts to date will save Rhode Island nearly $100 million in energy costs over the lifetime of projects implemented.[56]

The *2016 Plan* extends leading by example to municipalities and communities: "at the local level, cities and towns can play an important role in achieving state greenhouse gas targets by integrating mitigation into community planning efforts, setting their own reduction goals, investing in clean energy projects, and directly engaging with diverse community voices." Programs like the Municipal Resilience Program and the Shared Energy Manager pilot program have supported these local efforts. Localities have also demonstrated their leadership in climate planning and community engagement. For example, the City of Providence has been widely recognized for their 2019 Climate Justice Plan and applauded for process of co-development between their Office of Sustainability and the Racial and Environmental Justice Committee of Providence.

Leverage Regional Collaboration

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that "Rhode Island has a fruitful history of working cooperatively with neighbors to seek scalable, cost-effective solutions to mutual challenges; climate change mitigation is one such area that is ripe for strong regional partnerships." This strategy of regional collaboration has continued since 2016.

Regional Greenhouse Gas Initiative (RGGI)

The *2016 Plan* advocates for Rhode Island's continued participation in the Regional Greenhouse Gas Initiative (RGGI) and recommends advocating for program design elements that align RGGI emissions reductions with state climate mandates. Rhode Island has continued to be an active participant in RGGI since 2016. A program review is currently underway throughout 2021-2023, which will inform RGGI program design for future years.[57]

Transportation and Climate Initiative (TCI)

In accordance with *2016 Plan* recommendations to continue participation in the Transportation and Climate Initiative (TCI), Rhode Island continued to pursue TCI and consider legislation through 2021. However, in December 2021, neighboring states Connecticut and Massachusetts paused their participation in this effort. As this effort depends upon the involvement of at least three jurisdictions,

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[55] https://ripuc.ri.gov/Docket-22-49-EL
[56] Lead-by-Example 2020 Annual Report
[57] For more information about the RGGI Program Review and for opportunities to participate, visit https://www.rggi.org/.

Rhode Island cannot move forward with TCI at this time. However, key insights about priorities for program design and revenue investment should be considered in future policies and programs, and Rhode Island should leverage regional partnerships as opportunities arise.

New England Governors/Eastern Canadian Premiers

The *2016 Plan* supports Rhode Island's continued engagement with the New England Governors/Eastern Canadian Premiers (NEG/ECP). In 2018, NEG/ECP's Climate Change Steering Committee submitted the 2017 Update of the Regional Climate Change Action Plan and is currently working to execute this new report through various committees. Currently, there is a low level of activity in this regional organization.

Other Regional Work

The *2016 Plan* offers additional ideas for regional collaboration, including through renewable energy procurements and carbon pricing. Doing so is also a recommendation of the 100% Renewable Electricity by 2030 report. Regarding the *2016 Plan's* specific suggestions, Rhode Island leveraged a procurement by Massachusetts to contract for the 400 MW Revolution Wind offshore wind farm, and we conducted a study to examine the impacts of carbon pricing in 2020.

Also of note is a vision statement submitted in 2020 by the New England States Committee on Electricity (NESCOE, of which Rhode Island is a member) to ISO-NE, the organization that operates and maintains our region's transmission system. The NESCOE vision statement lays out three recommendations: First, wholesale markets need to be redesigned such that state-procured renewable energy systems are accounted for and properly valued. Second, transmission planning needs to account for substantial long-term deployment of renewable energy resources to meet states' decarbonization goals. Third, ISO-NE's governance needs to better reflect states voices and improve opportunities for public participation. Through NESCOE, New England states continue to work collaboratively to improve our regional transmission system.

In relation to transportation emissions: recognizing the urgent need for action, a diverse coalition of jurisdictions across the United States and Canada has committed, through the Multi-State Medium- and Heavy-Duty Zero Emission Vehicle (ZEV) Memorandum of Understanding (MOU), to work to reduce greenhouse gas emissions and harmful air pollution by accelerating the market for zero-emission trucks, vans, and buses. To achieve a timely transition and ensure near-term progress, the participating jurisdictions committed to strive to make at least 30 percent of sales of new medium- and heavy-duty vehicles ZEVs by 2030, and 100 percent of sales ZEVs by no later than 2050.

To translate commitment into action, the MOU directed the participating jurisdictions to develop a Multi-State Medium-and-Heavy-Duty (MHD) ZEV Action Plan to recommend policy options to foster a self-sustaining market. Released in July 2022, the Action Plan includes more than 65 recommendations for state policymakers to support the rapid, equitable, and widespread electrification of MHD ZEVs.

Meeting our 2030 Mandate

This section identifies recommendations for discrete priority actions by sector. Whereas the *2016 Greenhouse Gas Emissions Reduction Plan* offered "a broad framework to achieve the Resilient Rhode Island greenhouse gas reduction targets," this *2022 Update* recommends more granular actions needed in the short-term in order for Rhode Island to get on track to meet our 2030 emissions reduction mandate set forth by the 2021 Act on Climate. These priority actions are informed by all of our progress since 2016 – including studies, policies, and experience gained – as well as by stakeholder input.

The priority actions presented here are not comprehensive. We choose to focus on coordinated systems-level interventions that will either ensure or enable we meet our 2030 mandate. Instead of prescribing specifics for each action, we discuss the nuances of select factors that may be refined in order to advance policy co-objectives. Our intent is to elucidate the tradeoffs of certain refinements such that legislators, policy makers, and stakeholders can make decisions with the best understanding of impacts across the policy landscape.

In focusing on systems-level interventions, we de-emphasize priorities for individual action. This is not intended to downscale the importance of our individual decisions within our collective impact. Individual choices to reduce the greenhouse gas emissions within our control is fundamental and necessary for meeting Rhode Island's climate mandates. Indeed, we want to empower and encourage all Rhode Island households and businesses to reduce their own greenhouse gas emissions and prepare for impacts of a changing climate. Public administrations should lead by example here.

We also choose to focus on actions needed within the near future, when Rhode Island's comprehensive climate strategy is due and programs launching now will begin to take hold. The *2025 Climate Strategy* will include additional short-term and long-term actions to ensure Rhode Island meets is climate mandates through 2050.

Please also note that these actions have been restructured relative to the pathways identified in the *2016 Greenhouse Gas Emissions Reduction Plan.* This restructuring is intended to better align our strategic framework with how we think about our emissions inventory and the portfolio of analyses conducted since 2016. However, the pathways described in the *2016 Greenhouse Gas Emissions Reduction Plan's* broad framework comprise the foundation for the following short-term strategy.

Customized Emission Modeling Scenario for the 2022 Update

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with RMI and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by Acadia Center utilizing the *Energy Policy Simulator* (EPS) developed by Energy Innovation and RMI. By modeling a short list of key policy scenarios as outlined below, it is projected that Rhode Island slightly misses the Act on Climate's 2030 reduction mandate of 45% by 0.5 $MMTCO_2e$. To put this in perspective, the emissions in 2030 are projected by the EPS to be approximately 7.39$MMTCO_2e$, as compared to the 1990 baseline of 12.48 $MMTCO_2e$.

The EPS created a '2030 Climate Plan' scenario for Rhode Island using a number of realistic, actionable policies the state could adopt in the next decade.

Transportation

The EPS created a '2030 Climate Plan' for Rhode Island using various transportation policies the state is likely to adopt in the next decade. Clean transportation-related policies provide the greatest greenhouse gas emissions reductions. The following transportation policies help Rhode Island move towards the Act on Climate's 2030 GHG emissions reduction mandate of 45% below 1990 levels.

1. **Increase Adoption of Electric Passenger Vehicles**

   - Rhode Island can adopt California's *Advanced Clean Cars II* regulation as a Section 177 state. *(See Transportation Priority Actions for definition of a Section 177 state).*
   - If Rhode Island adopted *Advanced Clean Cars II*, **68% of all new passenger vehicles sold** in the state would be electric in 2030.
   - Adoption of the *Advanced Clean Cars II* helps Rhode Island **avoid approximately 0.29 MMTCO$_2$e emitted** in 2030.
   - Of the clean transportation-related policies, an estimated 88.5% of emissions reductions are attributed to switching to electric passenger vehicles.
   - In addition, an estimated 10.2% of all GHG emissions reductions modeled in the EPS are attributed to adopting more electric passenger vehicles.

2. **Increase Adoption of Electric Trucks & Buses**

   - Rhode Island can also adopt California's *Advanced Clean Truck* and *Medium-and-Heavy-Duty Omnibus* regulation to decarbonize large trucks and buses.
   - If Rhode Island adopted these regulations, **36% of all large trucks and buses sold** in the state would be electric in 2030.
   - Adoption of more electric trucks and buses helps Rhode Island **avoid approximately 0.04 MMTCO$_2$e emitted** in 2030.
   - Of the clean transportation-related policies, 11% of emissions reductions are attributed to switching to electric heavy-duty trucks and buses.
   - Also, 1.3% of all GHG emissions reductions modeled in the EPS are attributed to increased adoption of electric trucks and buses.

3. **Increase Decarbonization of RIPTA's Bus Fleet**

   - Another policy to reduce transportation-related greenhouse gas emissions is RIPTA's Zero Emissions Fleet Transition Program.
   - The EPS modeled the emissions reductions if **electric buses account for 17.7% of total miles travelled by the RIPTA bus fleet** in 2030.
   - An estimated **0.0004 MMTCO$_2$e** of GHG emissions would be avoided in 2030 with RIPTA's Zero Emissions Fleet Transition Program.
   - Of the clean transportation-related policies, 0.1% of all transportation emissions reductions are attributed to RIPTA's Zero Emissions Fleet Transition Program.
   - Additionally, 0.01% of all GHG emissions reductions modeled are attributed to the increased decarbonization of RIPTA's bus fleet.

4. **Expand RIPTA Ridership to Reduce Light Duty VMT**

   - Another powerful policy to reduce GHG emissions is known as "mode shifting".
   - Under this scenario, the EPS modeled the emissions reductions of a **4.8% reduction in vehicle miles travelled by single occupancy vehicles** below 2020 levels by 2030.

- Mode shifting reduces vehicle miles traveled (VMT), which takes more vehicles off the road and reduces traffic congestion.
- Through this scenario, Rhode Island **avoids approximately 0.23 MMTCO$_2$e** of GHG emissions in 2030.
- 7.9% of all GHG emissions reductions modeled in the EPS are attributed to mode shifting.

Altogether, clean transportation-related policies modeled in the EPS help Rhode Island avoid 0.56 MMTCO2e of GHG emissions in 2030.

Thermal - Energy Code

1. **Strengthen RI's Building Energy Code**

- More efficient building codes are vital to eliminate wasted energy, lower energy bills, and reduce carbon emissions that cause climate change.
- Under this scenario, the EPS modeled continuous adoption of the most recent IEEC model energy code for residential buildings and the most recent ASHRAE Standard 90.1 for commercial buildings for all code cycles falling between 2021 and 2030.
- Improvements to energy code efficiency requirements combined with an estimated rate of new construction in the state over the next decade results in an estimated **1.3% reduction in total building energy use in the state by 2030** relative to the BAU scenario.
- Through this scenario, Rhode Island **avoids 0.04 MMTCO$_2$e** of GHG emissions in 2030.
- 1.5% of all GHG emissions reductions modeled in the EPS are attributed to strengthening energy codes.

Thermal - Electrification

1. **Increase Efficient Electrification of Building Space and Water Heating**

- The persistent reliance on fossil fuels makes buildings one of the largest sources of GHG emissions.
- Under this scenario, the EPS modeled an **aspirational target of 15% of space and water heating demand in all buildings** being provided by efficient electric appliances (e.g., heat pumps and heat pump water heaters) by 2030.
- The EPS analysis shows that 22% of sales of new non-electric space heating equipment and 8% of the sales of new non-electric water heating equipment are replaced with the sale of efficient electric equipment from 2021 to 2030.
- Through this scenario, Rhode Island **avoids approximately 0.19 MMTCO$_2$e** of GHG emissions in 2030.
- 6.7% of all GHG emissions reductions modeled in the EPS are attributed the efficient electrification of building space and water heating.

Land Use

1. **Adopt a No Net Loss Forest Policy**

- Trees and vegetation absorb and store carbon dioxide. If forests are cleared, or even disturbed, they release greenhouse gases. Forest loss and damage cause rising GHG emissions.

- Under this scenario, the EPS modeled the adoption of a statewide policy that results in maintaining the existing amount of total forested land (~361,000 acres) in Rhode Island through 2030.
- A no-net loss forest policy through 2030 does not further reduce carbon emissions, but helps limit increases in carbon emissions.
- Further avoidance of forest loss helps steady Rhode Island's ability to sequester carbon.

Please take note of the following key issues which are further explained in the technical appendix attached to this report.

- The EPS uses 2020 as a starting point for Rhode Island when undertaking its modeling for 2030. Note that it is a *projected* estimate (RIDEM has yet to complete a full inventory for 2020).
- The EPS utilizes a generation-based approach for the electric sector that also incorporates RIs renewable energy standard. RIDEM's GHG inventory uses a consumption-based methodology that also incorporates RI's RES. This is an important fact that needs to be acknowledged.
- Rhode Island's recently enacted Renewable Energy Standard and Biodiesel Heating Oil Act (RIGL § 23-23.7) adopted in 2013 and amended in 2021 are directly incorporated into the EPS and accounted for in the '*Business as Usual*' scenario because they have already been adopted into law. Please note that in accordance with the Biodiesel Heating Oil Act, the percent of heating oil composed of bioproduct is assumed to achieve the following blend rates: 2020 (5%), 2024 (15%), 2025 (20%), and 2030 (50%).
- RI's leak prone pipe replacement program was not examined as part of this analysis because the level of uncertainty surrounding EPA's per mile emission factors is too high. We propose that this issue be examined in greater detail for the 2025 Climate Strategy as informed by the Public Utility Commission's (PUC) Future of Gas docket (commencing in 2023).
- The scenarios modeled in the EPS primarily focused on policies considered for adoption between 2020 and 2030.

The most important takeaways from this high-level analysis are:

- Electrifying the transportation sector and installing efficient electric appliances for space and water heating (e.g., heat pumps) combined have the most significant impact on GHG reductions in RI between 2020 and 2030.
- Adoption of all the scenarios previously discussed result in a 40.8% reduction in GHG emissions by 2030.
- Although the model indicates RI is projected to be 6.6% away from the Act on Climate's 45% reduction mandate in 2030, adoption of the highlighted policies is critical to putting the state on the correct path for large-scale emissions reductions.

Please refer to the technical appendix for further details and explanation of the EPS methodology and policy assumptions used.

Climate Change: Local Action for a Global Issue

The following is an excerpt from the RIEC4 Event: A Conversation with Senator Whitehouse, hosted on February 11, 2022.

Question: How do you respond to people who say, "Hey it's just little Rhode Island, it's not going to make any difference?" What do you think the value is of the work that we're doing, in terms of leading by example, or just trying to set the stage for bigger things?

Senator Whitehouse:

> *It was little Rhode Island that created the first conservation-based electric rates in the country back in the late 80s when it was still Narragansett Electric and now you see those everywhere. It was an entirely new way of thinking about regulation and how you compensate utilities, not for selling more electricity, but for actually reducing how much they create and burn.*
>
> *So Little Rhode Island has had some big, big leadership that plays out still across the country and, frankly, across the world, so, you know everything has to start somewhere, but was it Margaret Mead that said "never doubt that a small group of committed individuals can change the world - in fact, it's the only thing that ever has". We can be that small group of determined people in a lot of ways, and then good ideas take on a life of their own.*

Priority Actions for the Electric Sector

There are two ways to reduce emissions from the electric sector: consume less electricity and meet electricity needs using decarbonized energy resources. The Rhode Island General Assembly enacted a 100% Renewable Energy Standard that must be met by 2033. The 100% Renewable Energy Standard is expected to grow demand for renewable energy resources; this, in turn, will require strategic investments in our electric grid to enable timely and efficient integration of these resources, as well as bolstering cost-effective renewable energy within Rhode Island's portfolio through procurement of offshore wind. All actions must be considered within the larger fabric of policy objectives, and should be refined to improve affordability, equity, land use, and other policy objectives. The following table summarizes priority actions, which are described in more detail below. We additionally summarize recommendations from key recent and relevant studies in recognition that action must happen across the board.

Table X. Summary of Priority Actions in the Electric Sector

Action	Impact	Lead(s)	Select Considerations
Implement the 100% Renewable Energy Standard	100% reduction in greenhouse gas emissions when 100% target is achieved through REC retirement	Public Utilities Commission	Track schedule of increasing requirement yearly through 2033
Modernize the electric grid	Enables the electric grid to more readily integrate distributed energy resources and improve	Electric distribution utilities propose investments	Timing of investments, scale of investments, use of technologies

	customer energy management	Public Utilities Commission regulates	
Deploy advanced metering	Enables time-varying utility rate designs; allows customers to better manage their energy use; provides additional visibility into the electric grid	Electric distribution utilities propose investments Public Utilities Commission regulates	Interaction with grid modernization proposal, timing of deployment, subsequent rate design considerations
Procure offshore wind	Expands renewable energy generation portfolio	Electric Distribution Utility Public Utilities Commission regulates	Local economic development, scale and timing, contract structure
Continue energy efficiency work	Continue and further evolve programs to capture additional energy savings	Utilities	Effective investments
Complete RGGI Program Review and implement suggested changes	Supports regional decarbonization	RIDEM	Equitable investments

Implement the 100% Renewable Energy Standard

During the 2022 legislative session, a 100% Renewable Energy Standard (RES) was passed by the RI General Assembly and signed by Governor McKee. The RES ensures we decarbonize the electric sector with yearly targets. Rhode Island's Renewable Energy Standard is an existing statutory mechanism by which we can require electricity suppliers to meet an increasing percentage of retail electric sales from renewable energy resources. The Renewable Energy Standard also sets forth an accounting methodology and process to ensure compliance.

The newly passed Renewable Energy Standard, initially enacted in 2004 and subsequently revised in 2022, sets a statewide target of 100% renewable energy by 2033. Electric distribution companies and non-regulated power producers must comply with the mandate by supplying an increasing percentage of their retail electric sales from renewable energy resources through the purchase and retirement of Renewable Energy Certificates (RECs).[58]

[58] See the discussion on pages 25-28 in the Greenhouse Gas Emissions Inventory chapter for a complete description of how the Renewable Energy Standard works and its interaction with Rhode Island's greenhouse gas emissions inventory.

The impact of a 100% RES is that the emissions reduction may be as large as fully eliminating emissions from the electric sector, as it relates to electricity as an end-use. In 2019, emissions from electricity consumption were estimated to account for 18.9% of total economy-wide emissions. If the 100% Renewable Energy Standard were met in whole by the purchase of Renewable Energy Certificates, then Rhode Island would reduce its greenhouse gas emissions by 18.93%. [59] [60] [61] [62]

The schedule and yearly targets set forth in the 100% RES mandate steadily increase over time starting with an additional four percent of retail electricity sales in 2023 and increases until an additional 9.5% of retail electricity sales are needed in years 2032 and 2033. Additionally, the law requires municipalities participating in municipal aggregation to possibly include voluntary renewable energy products to be counted toward the annual targets.

Any impact to electricity costs should be considered within a larger macroeconomic context. For instance, the war in Ukraine has and will continue to result in increased fuel prices, which in turn increase electricity supply costs. Communities continue to struggle with the economic downturn from the COVID-19 pandemic. Supply chain challenges are not only delaying shipments necessary to our energy landscape but are causing cost increases as well for commonplace technologies. However, implementing the 100% Renewable Energy Standard is one of the most important steps Rhode Island has taken towards statewide, economywide decarbonization.

Modernize the Electric Grid

The current electric grid is built for one-way flow of electricity from a few large power generators to many end-use customers. However, decarbonizing the electric grid necessitates a paradigm of two-way power flow between renewable energy systems of all sizes distributed throughout the electric grid to all customers. Safely, reliably, and affordably building out the electric grid will require electric distribution companies to make strategic investments in technologies for a twenty-first century electric grid.

Grid modernization technologies serve the purpose of managing power flow, protecting workers and customers, improving visibility into electricity consumption and grid conditions, building resilience from power outages, and giving customers more choice and control over their electricity use.

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[59] This simple estimate is *ceteris paribus*: the estimate assumes all else is held equal (e.g., no increase in electricity consumption) and only the Renewable Energy Standard is changed.

[60] More completely: Rhode Island would reduce its emissions by 26.3% below 2018 levels. Emissions resulting from electricity consumption in 1990 were estimated using a different methodology that prevents robust sector-specific comparison between years.

[61] This statement is true if our annual emissions accounting methodology is in place. If instead Rhode Island were to move to a more temporally granular method of emissions accounting, then the emissions reduction impact of a 100% Renewable Energy Standard would be smaller. If hourly accounting capabilities are available, Rhode Island can then consider the value of enacting a more stringent Renewable Energy Standard that requires the timing of renewable energy production (or more specifically, its release into the electric grid for retail consumption) to match the timing of demand. See, for example, Massachusetts's Clean Peak Standard or discussions of private investment in 24/7 clean energy. Moving to this level of standard would not be without cost (e.g. required for energy storage build out), so we recommend first prioritizing increasing the Renewable Energy Standard and then exploring any further enhancements in the 2030s and 2040s, when hourly accounting capabilities exist for both emissions and Renewable Energy Certificates and energy storage is more commonplace and less expensive.

[62] This estimate excludes emissions resulting from methane leakage in Rhode Island's gas distribution system where that gas is used to fuel electricity generators. As gas-fueled electricity generators decrease production in Rhode Island, emissions from methane leakage will decrease accordingly.

Deploy Advanced Meters

Meters that measure electric (and gas) consumption for utility accounts range in capability from simple counting and aggregation of energy use over a billing period to detailed accounting of consumption throughout minutes-long intervals and real-time communication with customers. Most meters in Rhode Island are more like the former – conventional meters that report how much energy a customer uses over the course of a month – and the majority of those meters are reaching the ends of their useful lives.

As Rhode Island considers how to replace its legacy meter system, advanced meters may be the more cost-effective option that also supports progress toward our climate mandates. The granularity of data and method of data communication that advanced meters use allows for innovative rate designs that deliver appropriate signals about the true cost of electricity use throughout the day and year, enables customers to better understand and control their electricity use, and provides important visibility into the electric grid that allows us to make the most use of our infrastructure.

Procure Offshore Wind

Offshore wind is a not only a vital renewable energy resource but a significant economic driver of growth and jobs in Rhode Island. As we move to implement the 100% Renewable Energy Standard, offshore wind will play a critical role in affordably meeting both our in-state renewable energy requirements as well as supporting the region as a whole.

On July 6, 2022, Governor Dan McKee signed a bill into law adding 600 to 1,000 additional megawatts of offshore wind to Rhode Island's clean energy portfolio. Rhode Island Energy released a request for proposals for public comment through the Public Utilities Commission in the Fall of 2022. RIE formally released the RFP in October and responses by interested bidders are expected in early 2023. A final decision on the winning projects will occur later in the year, and contract(s) with developers will be reviewed and approved Public Utilities Commission. It is expected that any new offshore wind projects procured through the RFP would be operational during the first half of the 2030's.

Continue Energy Efficiency Work

Energy efficiency programs in Rhode Island helps residents and businesses adopt and install technologies that allow them to receive the same or better performance from their equipment, buildings, and appliances while using less energy. Rhode Island's energy efficiency programs are offered through the state's utilities and from the Rhode Island Office of Energy Resources. These services can directly lower energy bills for participating consumers, reducing both emissions and energy costs for all consumers, which help support the local economy, and combat climate change. Since 2005, ratepayer-funded energy efficiency programs have saved Rhode Island consumers about 15,400 GWhs of electricity. The impact of these savings means that Rhode Island's electric load is 9% lower than it was in 2005. Since 2009, Rhode Island's ratepayer funded energy efficiency programs have provided over $4.5 billion in realized benefits. This compares to total program costs of about $1.6 billion, resulting in a cumulative benefit-cost ratio of 2.8.[63] In 2021, Rhode Island's least cost procurement statute was extended to 2029, which ensures the energy efficiency programs for the next seven years.[64]

[63] Rhode Island Energy Efficiency and Resource Management Council 2022 Annual Report
[64] Least Cost Procurement: http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM

Complete RGGI Program Review and implement suggested changes

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia to cap and reduce CO2 emissions from the power sector. It represents the first cap-and-invest regional initiative implemented in the United States. Rhode Island has continued to be an active participant in RGGI since 2009. A Third Program Review is currently underway throughout 2021-2023, which will inform RGGI program design for future years. Once the ongoing Third Program Review is completed, Rhode Island can examine adopting new program design elements aimed at continued reduction in greenhouse gas emissions in Rhode Island and the region. The 2025 Climate Strategy should be informed by and responsive to the recommendations of the RGGI Third Program Review.

Table X. Summary of Remaining Recommendations for the Electric Sector from Select Recent and Relevant Studies

Report Title	
Status	Recommendation
100% Renewable Energy by 2030	
Complete [65]	We must ensure we meet our clean energy goals by advancing a 100% Renewable Energy Standard.
Complete [66]	Continued efforts to decrease energy consumption necessitate extension of Least-Cost Procurement and Nation-Leading Energy Efficiency Programs.
Underway [67]	Maintain continued support for in-state renewable energy development, while supporting programmatic evolution to deliver more affordable and sustainable outcomes.
Underway [68]	Optimize the electric grid through integrated grid planning.
Priority action [69]	Facilitate integration of distributed energy resources by deploying Advanced Metering Functionality and Grid Modernization technologies.
On the horizon[70]	Build out a strategic role for energy storage technologies.
Underway [71]	Continue regional collaboration on wholesale markets and interstate transmission.

[65] RIGL39-26.4
[66] RIGL39-1-27.7
[67] The Division of Public Utilities and Carriers is conducting a study to understand programmatic costs and benefits.
[68] The Office of Energy Resources, National Grid, Regulatory Assistance Project, and Lawrence Berkeley National Lab are developing an exploratory pilot project to understand process options and viability.
[69] Modernizing the electric grid, which includes upgrading metering functionality, is a priority action for the short-term. Other recommendations from the Power Sector Transformation Report are noted within this table.
[70] This recommendation is ripe for further consideration and discussion in the development of the *2025 Climate Strategy*.
[71] See https://newenglandenergyvision.com/ for more information about this effort.

Needs more work	Partner with trusted community organizations to listen, learn, support, and establish foundational definitions. Based on foundational definitions, develop equity metrics with the community to track and monitor progress towards equitable outcomes. Improve outcomes identified and prioritized by communities through rate design, program adjustments, and policy.
Power Sector Transformation	
Implemented [72]	Create a multi-year rate plan and budget with a revenue cap to incentivize cost savings.
Ongoing [73]	Shift to a pay-for-performance model by developing performance incentive mechanisms for system efficiency, distributed energy resources, and customer and network support.
Ongoing[74]	Develop new value streams from the distribution grid to generate third-party revenue and reduce burden on ratepayers.
Ongoing	Update service quality metrics to address today's priorities, including power outage prevention, cyber-resiliency, and customer engagement.
Needs more work	Assess the existing split treatment of capital and operating expenses.
Priority action	Deploy advanced meters.
Ongoing	Plan for third-party access and innovation.
Ongoing	Share the cost burden of advanced metering through partnerships.
Ongoing	Focus on capabilities to avoid technological obsolescence.
Ongoing	Proactively manage cyber-resilience.
Implemented [75]	Synchronize filings related to distribution system planning.
Ongoing	Improve forecasting.
Ongoing	Establish customer and third-party data access plans.
Ongoing [76]	Compensate locational value.

[72] See Commission Docket 4770.
[73] See for example Commission Docket 4943.
[74] This will likely be a consideration in any future electric distribution utility filing requested cost recovery for investments in grid modernization and advanced metering. See stayed Commission Dockets 5113 and 5114.
[75] See Commission Docket 5015.
[76] See for example National Grid's process for procuring non-traditional electric grid solutions.

Ongoing and on the horizon [77]	Design rates to increase system efficiency.
Ongoing	Establish outcome-based metrics.
Needs more work	Beneficial heating proposals should be consistent with principles outlined in the Commission white paper on beneficial electrification.
Solar Siting Opportunities	
Ongoing	This report estimated viability of solar in preferred locations. Considerations are embedded throughout the report,
Docket 4600	
Ongoing	This report included a number of next steps for the Public Utilities Commission to consider, some of which fed into the Power Sector Transformation report and subsequent work to develop a grid modernization plan and advanced metering functionality business case in collaboration with National Grid's Power Sector Transformation Advisory Group.
Energy Efficiency Market Potential Study	
Ongoing	There is significant opportunity to expand DR programs in RI in a cost-effective manner, both through growing the market for existing programs, and introducing new measures and programs.
Ongoing	C&I lighting remains by far the largest opportunity, both in terms of annual and lifetime savings.

Building an Integrated Portfolio of Action

Framing our emissions reduction journey by the largest emissions categories— thermal, transportation, and electric—provides a clear starting point for assessing our baseline and organizing our actions. As we move along in the process, however, it becomes clear that we cannot draw clear lines between these sectors. So many systems, both big and small, overlap and these overlaps will only continue to change, as we adjust the way we do things to decrease our emissions.

For example, our food systems produce emissions through agricultural practices, processing, distribution, refrigeration, cooking, and waste. This one supply chain includes emissions from the electric sector, the transportation sector, and the thermal sector. Another example is heating. We currently use a mix of fuels and technologies to heat our buildings, and as we decarbonize, that mix will continue to change, overlap, and have greater implications on other sectors. When we begin to look at the ways in which different areas of our energy usage are integrated with each

[77] In Commission Docket 4770, the Commission approved a performance incentive for meeting system efficiency targets; however, rate designs specifically targeting system efficiency are not likely to be proposed until metering functionality is improved (i.e. such as to allow for time-varying rate structures).

other, we can find additional priority actions that more strategically reduce emissions across the board.

As policymakers, we often rely on benefit-cost assessments to understand the potential impacts of choosing different options. When we conduct benefit-cost assessments on single actions, or sets of siloed actions, we lose sight of the integrated and indirect benefits and costs that ripple throughout the entire system. Looking at the big picture, can change how we interpret the benefits and costs in a small part of it.

For example, if we prioritize only the low-hanging fruit—actions with the biggest benefits and the lowest costs—then we may find ourselves in a place where our remaining actions are no longer cost-effective. We also run the risk of not seeing the full scale of benefits across our holistic set of policy objectives. Looking at the collective benefits and costs of an entire portfolio of actions, can help us see the full effect of our actions.

It is for this reason that, in this report, we not only organize our priority actions by sector (electric, transportation, thermal, land use, etc.) but we also include these integrated callouts on health, food systems, buildings, and youth. Discussing these integrated systems helps us understand additional priority actions that we must take, not only to meet our climate mandates, but also to improve things like the health, comfort, safety, affordability, resilience, equity, and the vibrancy of our Rhode Island communities.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a multi-state, market-based program to cap and reduce carbon dioxide (CO_2) emissions from electricity generating power plants. Through independent regulations (based on the RGGI "Model Rule"), twelve Eastern states currently participate in this cooperative effort. Launched in 2009, RGGI was the first mandatory greenhouse gas "cap-and- invest" program in the United States. The regional cap on CO_2 emissions is set by the RGGI states. Together, the RGGI states' individual emissions caps (or CO_2 budgets) are equal to shares of the regionwide cap. This cap sets a limit on the emissions from regulated power plants in the RGGI states' and declines over time in a planned and predictable way.

Since its conception, RGGI emissions have been reduced by more than 50% RGGI-wide and the RGGI program has contributed to the decarbonization of the electric sector. Fossil fuel-fired power plants with a capacity of 25 megawatts or greater must acquire enough RGGI allowances to cover their CO_2 emissions. Electric generation facilities in the RGGI states obtain allowances primarily through quarterly auctions. The RGGI states receive the proceeds from selling RGGI allowances and each state has discretion over how best to use their proceeds. Over $5 billion has been raised RGGI-wide from the allowance auctions. Generally, the proceeds have been invested by states back into their communities including funding of energy efficiency, clean energy programs, renewable energy deployment and direct rate relief for low-income consumers. As of September 2022, RI's proceeds from all auctions total approximately $116 million.

The RI Office of Energy Resources (OER) with guidance from RIDEM determines the allocation and distribution of RI's RGGI auction proceeds. In 2022, RI auction revenue supported numerous programs including the RI Commerce Corporation's Renewable Energy Fund (REF), LED *lighting in public schools, air-source heat pump incentives, RIDEM Energy-Savings Trees Program and RI Agricultural Energy Grant Program. Two programs directed towards low- and moderate- income (LMI) customers; the Affordable Solar Access Pathways Program (ASAP) and the Zero Energy for the Ocean State (ZEOS) were also funded by RGGI auction proceeds. In addition, approximately 5 million in electric bill credits to low-income customers were also supported by RGGI revenues.*

Priority Actions for the Transportation Sector

There are two ways to reduce emissions in the transportation sector: consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions and take action to incentivize lower-emissions mobility.

Table X. Summary of Priority Actions for the Transportation Sector

Action	Impact	Lead(s)	Select Considerations
Increase light-duty ZEV penetration to at least 10% by 2030.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	Administration (RIDOT, RIDEM, OER, DMV, Commerce, RIIB)	Incentive programs, interaction with electric vehicle charging infrastructure. State fleet transportation Lead by Example.
Implement Transit Forward RI 2040, Rhode Island's Transit Master Plan, to grow transit ridership from 53,000 to 87,000 daily passenger trips. Look to the Transit Master Plan and Bicycle Mobility Plan for next steps and consider committing resources to key projects.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIPTA, Division of Statewide Planning, RIDOT	This will mitigate 231,000 MTCO2e. [78] Projects in the TMP and BMP are planned on a conceptual level. The next step is to evaluate needs and connections.
Reduce RIPTA's carbon footprint by decarbonizing Rhode Island's transit fleet.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIPTA	This will mitigate 14,122 MTCO2e. [79]
Maintain increasing fuel economy and low-and zero-emission vehicle standards.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIDEM	Maintain adherence to Corporate Average Fuel Economy and GHG emission standards.

[78] Estimates are from the TCRP Land Use Benefit Calculator as provided by RIPTA.
[79] Estimates are from the TCRP Land Use Benefit Calculator as provided by RIPTA.

			Maintain adherence to California low-emission and zero-emission vehicle requirements. Includes amending existing rules to incorporate Advanced Clean Cars II. Adopt New Rules: California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers.
Incentivize electric mobility	Enables switch to electric vehicles	Office of Energy Resources	New and used, personal and fleet, BEV, PHEV and MHD, future expansion of incentives to e-bikes. Utilize Diesel Emissions Reduction Act (DERA) funds to provide incentives to RI entities to replace older diesel engines and vehicles with cleaner and zero-emission alternatives.
Model climate impacts of transportation demand (in Unified Planning Work Program)	Allows weighing climate impacts of transportation investment decisions among policy objectives	Division of Statewide Planning, RIDOT and RIDEM	This is not an issue only at the state level, but nationally and regionally. RIDOT and RIDSP will work together with other federal, state and regional partners to improve the GHG modeling capacities as this is a FHWA requirement for transportation capital projects and establish a model for decision-making.
Develop 'complete streets' state plan leveraging federal funding	Reduces fuel consumed through decrease in vehicle miles traveled and encourages lower-emissions mobility	Division of Statewide Planning, RIDOT and RIPTA	The IIJA resulted in specific formula funding set-asides for developing a Complete Streets plan and implementation strategy: RIDSP will be the lead but work closely with a robust group of partners and stakeholders. Anticipated completion in 2025.

Target 10% penetration of electric vehicles by 2030

In the latest Rhode Island Greenhouse Gas (GHG) Emissions Inventory report, the Transportation sector was responsible for the highest gross greenhouse gas emissions (39.7%) by economic sector in 2019. Emerging technologies in the transportation sector, such as electric vehicles, are paving the way for alternative fuels to be used as a solution for reducing GHG emissions. Clean transportation will also deliver substantial energy security and economic benefits as cleaner electricity derived from renewable energy and other low-carbon sources replaces imported gasoline and diesel as transportation fuels.

As of October 2022, Rhode Island has 6,275 registered electric vehicles, which is a 1,313% increase in EVs since 2015. In order for the transportation sector to meet its 2030 emissions reduction, Rhode Island will need to have roughly 43,000[80] registered EVs on the road. By having programs focused on Zero-Emission Vehicles, such as DRIVE EV, an electric vehicle rebate program available to Rhode Island residents and businesses, it will help increase the amount of registered electric vehicles on the road in Rhode Island as mandated by the 2021 Act on Climate, as well as paving the way for further expansion of EV penetration, post 2030.

Implement Transit Forward RI 2040

Implementing the plan will require an approximate average annual capital investment of $100-160M over 20 years. Operating costs will increase roughly $150M annually, from $130M (2020) to $280M). This action is estimated to grow transit ridership from 53,000 to 87,000 daily passenger trips and to mitigate 231,000 MTCO2e,

As resources are available, look to the Transit Master Plan (TMP) and Bicycle Mobility Plan (BMP) as well-vetted strategies for next steps

RIDOT, RIPTA, and RIDSP have all developed planning work tasks to support mapping, evaluation, and implementation of projects and priority corridors which were recommended in the TMP or BMP respectively. These agencies continue to prioritize projects advancing better connections for both transit and bicycle/pedestrian modes as the state looks to identify funding for the TMP and BMP. Some of the projects related to these steps include funding for long-range planning studies that take conceptual proposals and prepare design and cost details. In addition, staff resources are used to map the projects in the BMP and TMP to show where overlap may occur with existing planned projects, allowing incorporation of bike, pedestrian, and transit components into projects already programmed in the STIP.

Reduce RIPTA's carbon footprint by decarbonizing Rhode Island's transit fleet.

The full cost of fleet decarbonization is currently unknown. RIPTA is preparing an Action Plan for Electrification and Service Growth which will provide estimated annual decarbonization infrastructure, vehicle, and energy costs. This plan will be complete by June of 2023.

Adopt Advanced Clean Trucks rule

The federal Clean Air Act (CAA) grants the U.S. Environmental Protection Agency (EPA) original jurisdiction for establishing emission standards for new motor vehicles, including heavy-duty trucks. Section 209(a) of the federal Clean Air Act (42 USC § 7543) prohibits states (except California) or other political sub-divisions, such as local or regional governments, from establishing emission standards for new motor vehicles.

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[80] This estimate is based on an internal scatter model used by Rhode Island Energy (RIE).

Under CAA Section 177 (42 USC § 7507), however, states that choose to adopt vehicle emission standards that are more stringent than the federal standards for new vehicles may adopt standards that are identical to any standards adopted by California.

Rhode Island has previously adopted California's emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California's standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles.

Reducing emissions from the vehicles on our road is an important part of Rhode Islands' programs to meet and maintain the health-based National Ambient Air Quality Standards (NAAQS), reduce the risk of exposure to toxic diesel particulate matter, and reduce the GHG emissions that contribute to climate change. The adoption of California's emissions standards is an imperative piece of the puzzle to Rhode Island's response and action on climate change.

Adopt New Rules: California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers.

- ACT: The purpose of the ACT Rule is to accelerate the widespread adoption of ZEVs in the medium-and heavy-duty truck sector and reduce the amount of harmful emissions generated from on-road trucks. The ACT Rule applies to manufacturers of medium- and heavy-duty vehicles over 8,500 pounds gross vehicle weight rating (GVWR)8 which includes passenger vans, buses, pickups, vocational trucks, box trucks, and tractor trailer combinations used locally and for long-haul applications. The ACT Rule requires manufacturers to sell ZEV trucks as an increasing percentage of their annual sales from model years 2026 to 2035. (**MY26 or MY27 pending if we move forward in 2022 or 2023).

- HD Omnibus: The Heavy-Duty Engine and Vehicle Omnibus (HD Omnibus) Rule and associated amendments require NOx reductions from new on road heavy-duty engines and vehicles and ensure emissions reductions are maintained as those engines and vehicles are operated. The HD Omnibus Rule requires a 90% reduction in NOx emissions from model year 2027 engines.

- Phase 2 GHG: The Phase 2 GHG Rule sets standards to reduce GHG emissions associated with medium- and heavy-duty engines, vocational vehicles, heavy-duty pick-up trucks and vans (PUVs), and applicable tractors and trailers. The Phase 2 GHG Rule requires manufacturers to improve existing technologies or develop new technologies to meet the GHG emission standards. It also amends requirements for glider vehicles, glider engines, and glider kits. The Phase 2 GHG requirements would apply to model year 2026 and newer Class 2b to 8 medium- and heavy-duty vehicles with greater than 8,500 pounds GVWR and the engines that power them, except for medium-duty passenger vehicles already covered in the light-duty regulations. (**MY26 or MY27 pending if we move forward in 2022 or 2023).

Avoided Medium- and Heavy-Duty Emissions, 2020-2040		
NOx (short tons)	PM2.5 (short tons)	CO2e (million metric tons)
4,740	25	1.96
Avoided Medium- and Heavy-Duty Emissions, 2020-2050		
13,080	76	5.59

Table: Cumulative emissions avoided with 2025 implementation of ACT, HD Omnibus, and Phase 2 GHG rules. [81]

Amend Existing Rules to incorporate California's Advanced Clean Cars II:

- Rhode Island Department of Environmental Management will also have the ability to amend our existing Advanced Clean Cars program to adopt California's Advanced Clean Cars II (ACCII). The ACCII ZEV regulation requires that all passenger car and light-duty truck vehicles delivered by manufacturers for sale in Rhode Island by 2035 meet the definition of zero-emission vehicle (ZEV). The ACCII regulation will reduce NOx, PM2.5, and GHG emissions. (**GHG reduction analysis pending)

Incentivize electric mobility

Rhode Island has a history of impactful planning and programming related to clean transportation programs. In the past, the Office of Energy Resources has successfully administered programs incentivizing electric mobility.

Program	Targeted Technology	Program Duration	% Increase
DRIVE	Electric Vehicles	January 2016 – July 2017	20-35% (254 EVs)
Electrify RI	Electric Vehicle Charging Stations	October 2019 – July 2021	83 Operational Charging Stations and 14 Pending Activation (as of August 24, 2022).

The success of the programs implemented in the table above provided several best-practices and mechanisms used to incentivize electric mobility. On July 7, 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program.

In the coming years, there will be opportunities to identify long-term, sustainable fundings sources to continue incentivizing electric vehicle adoption. An increased focus on providing additional incentives aimed at reducing the barrier-to-entry costs related to electric vehicles, as well as providing programs aimed at providing electric vehicle charging stations for non-homeowners, and those that live at multi-unit dwellings, as well as businesses looking to transition their fleet.

There are now programs, and incentive opportunities, available for e-bikes. The current DRIVE EV rebate program gives rebates for light-duty electric vehicles, and recently OER expanded the scope to include rebates for e-bikes.

Model climate impacts of transportation demand

Transportation accounts for the largest share of Greenhouse Gas (GHG) emissions in Rhode Island, with passenger vehicles being the largest contributor to pollution caused by transportation related emissions[82]. RIDOT and the Rhode Island MPO must adopt long-range transportation plans that reduce GHGs to set

[81] Source: ICCT Report "Benefits of state level adoption of MHDV Regulations" https://theicct.org/
[82] Per Transportation Emissions Dashboard | Rhode Island Department of Environmental Management (ri.gov)

reduction levels. Current air quality measurements and travel-demand models do not specify GHG levels as they pertain to transportation projects in the STIP, so a new model is needed.

To understand how projects of regional significance in the State Transportation Improvement Program (STIP) contribute to GHG emissions and to assess future policy options and investment strategies towards the reduction of those emissions, Rhode Island Department of Transportation (RIDOT) is working with other state partners to improve the modeling of GHG, establishing performance measures to help reduce emissions and creating a Carbon Reduction Plan per federal guidelines.

Investments in transportation capital projects are prioritized based on many factors, including asset management, readiness, risk levels, available funding and opportunities for partnership. Due to changes in both state and federal regulations and guidelines, this data-driven process now will include another layer that determines how regionally significant projects impact carbon emissions in the state. The state planning process determines these priorities so that adequate investments are made based on the proper funding sources and uses, and to meet mandates such as performance measures.

In addition, the Rhode Island Division of Statewide Planning (RIDSP) hosts and maintains the State's Travel Demand Model.

Develop 'complete streets' state plan leveraging federal funding

In addition to the state requirements around complete streets, Complete Streets law: http://webserver.rilin.state.ri.us/Statutes/TITLE24/24-16/24-16-1.HTM there is a federal requirement to develop a complete streets plan and design guidance. In December 2021, USDOT sent a letter to all state and regional offices to highlight new Planning Emphasis Areas (PEAs), which included Complete Streets as a focus for planning-level funds and projects. The IIJA requires that states and metropolitan planning organizations set aside 2.5 percent of their highway planning funding for designing "complete streets" projects and policies that will improve safety and accessibility for all users of the road.

USDOTs definition of "Complete Streets" as "Streets that are streets designed and operated to enable safe use and support mobility for all users. Those include people of all ages and abilities, regardless of whether they are travelling as drivers, pedestrians, bicyclists, or public transportation riders. The concept of Complete Streets encompasses many approaches to planning, designing, and operating roadways and rights of way with all users in mind to make the transportation network safer and more efficient. Complete Street policies are set at the state, regional, and local levels and are frequently supported by roadway design guidelines."

In Rhode Island, RIDOT and RIDSP have joined together to maximize the impact of that funding. RIDSP will lead a 2.5-year effort to invest more than $250,000 in combined planning funds into development of a Complete Streets Plan and Design Guidelines. This project has kicked off (fall 2022) with a draft RFP for consultant assistance, which RIDSP expects to complete and issue in spring 2023, in coordination with RIDOT and RIPTA. This project is included in the FY2023 Unified Planning Work Program (UPWP), is the annual RIDSP program of projects under development.

Electrifying Transportation Strategic Policy Guide [83]

In December 2021, '*Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island'* was released in response to S-0994 and H-5031, which directed numerous agencies to develop a coordinated plan to improve access to electric

[83] Please see the Electrifying Transportation Strategic Policy Guide for additional recommendations throughout the entire text of the report.

vehicle charging stations across the state. The policy guide highlighted the following key priorities for Rhode Island in the coming years:

- Reinvest in incentive programs for electric vehicles and charging infrastructure;
- Refine electric vehicle and charging infrastructure programs to align with priorities and to center equity such that benefits accrue to underserved and overburdened communities;
- Demonstrate progress in electrifying transit, school buses, and medium- and heavy-duty vehicles in order to reduce harmful emissions and improve public health;
- Conduct an analysis to understand transportation revenue impacts and develop recommendations for future action to ensure sustainable funding streams;
- Support a 100% Renewable Energy Standard to ensure electric transportation is truly decarbonized;
- Develop a clean transportation dashboard to track progress; and
- Demonstrate action through state agency commitments and accountability.

A number of these priorities have already been accomplished or are underway. A specific meaningful action item for all agencies represented by RIEC4 was included in the final guide. The RIEC4 should continue to track progress on all the agency specific action items and coordinate implementation across agencies to maximize impact. Looking ahead, the 2025 Climate Strategy will be able to revisit both the priorities outlined above and the agency specific action items and recommend changes as needed.

Climate and Buildings

Buildings are a significant source of greenhouse gas emissions and contributors to climate change. According to the American Council for an Energy-Efficient Economy (ACEEE), "residential and commercial buildings are responsible for approximately 40% of U.S. energy consumption and GHG emissions."[1] We live, work, and play inside buildings and the operations required to keep the lights on, operate our electronics and appliances, and keep our spaces comfortably heated or cooled require a lot of energy. Buildings also contribute to climate change through the construction process and the manufacturing of the materials necessary for construction. We create buildings to have very long lifespans, which means that how we choose to build or renovate them can have large impacts on the lifetime emissions of those buildings. Altogether, our built environment is both one of our largest contributors to climate change and one of our greatest opportunities for reducing our emissions.

Resilient buildings are important because buildings affect our climate, but our buildings are also impacted by our changing climate. In our coastal areas, flooding will become more common as sea levels rise. Across the state, storms will become more severe, and the number of high heat days that we have in the summer will increase. All of these changes mean that our buildings must also be constructed to be resilient in order to withstand these more intense impacts, and to keep the interiors of our buildings comfortable in more extreme weather conditions.

Decarbonizing the built environment is one way we can reduce GHG emissions of buildings. There are numerous considerations for decarbonizing the built environment that intersect across different sectors. For example, we typically use fossil fuels to heat our buildings, and we use electricity to power an increasingly wide range of appliances. One of the greatest uses of energy in buildings is for space heating and cooling. Switching to renewable sources for energy, heating and cooling our buildings can help to reduce the impact the built environment has on the climate.

Key considerations for the thermal sector and decarbonizing the thermal needs of buildings are issues addressed throughout this report.

We have a variety of tools available to us in Rhode Island to both reduce the emissions that come from our built environment and to strengthen the resilience and adaptability of our buildings.

Strengthen Building Energy Codes

> *Building codes are one of the tools available for improving our buildings. Building codes provide a baseline set of rules that all new construction projects must comply with to ensure the safety and energy efficiency of buildings. The State's building codes are generally updated every three years through a public process to raise the bar on the minimum standards of safety and efficiency. The State also has a stretch code in place, which is a more ambitious building code that developers can choose to comply with in order to build more efficient buildings. Building codes can help the State set the trajectory for net-zero green building standards, prepare our new buildings to be EV- and solar-ready, and prepare our buildings to be completely electrified.*

Implement the Updated Green Buildings Act Legislation and Continue to Assess and Recommend Opportunities for Improvement

> *The Green Buildings Act was signed into law in 2009 to require public agencies to design and construct projects and renovations to meet a LEED-certified of equivalent high performance green building standard. In 2022, the Green Buildings Act was amended to specify that these requirements apply to all new construction projects and renovations of 10,000 square feet or larger. The Green Buildings Act is administered by a Green Buildings Advisory Committee comprised of State agency representatives and members of the public. The Committee will continue to assess and evaluate the implementation practices of the Green Buildings Act, including conducting studies as needed, to provide recommendations for achieving the State's goals related to public facility emissions. By ensuring improved compliance with the Green Buildings Act, the State can help reduce emissions from public buildings and facilities throughout the state.*

Coordinate Climate Considerations with New Housing and School Investments that Use Public Money

> *There are many efforts being made to use public funds to reduce harmful climate impacts in the state, including with new housing and school investments. One program is the Zero Energy for the Ocean State (ZEOS) program, which is a partnership between the Office of Energy Resources and RI Housing. This program provides Regional Greenhouse Gas Initiative (RGGI) funding to affordable housing developments to create net-zero energy housing for low- and moderate-income residents. The State's School Building Authority is also able to leverage its funding to ensure that school construction projects are built to high energy and environmental standards. School districts looking to renovate existing buildings or construct new facilities can receive 30 to 98 percent in funding reimbursements for those projects, if the projects are constructed to meet the New England Collaborative for High Performance Schools criteria (NE-CHPS). State agencies continue to seek additional opportunities to leverage federal funding for reducing emissions from Rhode Island's built environment. These efforts will allow new building stock to advance climate mandates and deliver non-energy benefits to all.*

Priority Actions for the Thermal Sector

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island. Because of the variety of energy sources, emissions accounting for the thermal sector is spread across different categories in the state's greenhouse gas reporting. Over the next decades, the fuel sources we use for the thermal sector will begin to shift as we transition to lower emissions fuels.

At a high level, the two primary ways to reduce emissions from the thermal sector are to, 1) consume less fuel, and 2) to consume lower emissions fuels. Consuming less fuel means optimizing efficiency and reducing wasted fuel or heat that does not get used for its primary purpose or providing heating or cooling to Rhode Islanders. The ways we can use lower emissions fuels are summarized in Figure X and generally involve two over-arching pathways: strategic electrification and decarbonized fuels.

<table>
<tr><td rowspan="5">Thermal Processes</td><td rowspan="3">Strategic electrification</td><td>Air Source Heat Pumps (ASHPs)
-e.g., air to air, air to water heat pumps</td></tr>
<tr><td>Ground Source Heat Pumps (GSHPs)
-e.g., ground to air, water to air heat pumps, and geothermal district systems</td></tr>
<tr><td>Thermal Energy Storage
-e.g., heat batteries</td></tr>
<tr><td rowspan="2">Decarbonized Fuel</td><td>Renewable Liquid Fuels
-e.g., biodiesel, ethanol</td></tr>
<tr><td>Renewable Gases
-e.g., renewable natural gas, hydrogen</td></tr>
</table>

Figure X. Thermal Decarbonization Pathways (adapted from the Heating Sector Transformation Report)

Table X summarizes priority actions for decarbonizing the thermal sector. The priority actions focus on consuming less fuel, consuming lower emissions fuel, or a combination of both.

Table X. Summary of Priority Actions in the Thermal Sector

Action	Impact	Lead(s)	Select Considerations
Energy Efficiency			
Continue Energy Efficiency and Weatherization	Efficiency standards can continue to be improved for heating equipment, and weatherization incentives and programs can further be enhanced by the utilities and the state.	Utilities and State Agencies	Extensive federal funding for electrification is expected in coming years; weatherization programs should ramp up to use funding effectively

Strategic Electrification			
Target 15% penetration of energy efficient electric heating by 2030	≈ 0.19MMTCO2e reduction in greenhouse gas emissions (in 2030)	OER and RIE	Workforce training, consumer education, utility coordination
Pursue district geothermal	Pilot most efficient electric thermal system	OER and RIE	Utility coordination, community involvement, integrated systems and planning
Incentivize efficient electric heating technologies	Increases affordability of technologies and spurs market growth	State and federal government	Funding streams and associated limitations, consumer and contractor trust and awareness
Decarbonized Fuels			
Increase biofuel blending in accordance with the 2021 Biofuel Heating Oil Act	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	Industry	Equipment compatibility, cost and quantity of supply, life cycle carbon intensity and environmental impact
Continue to abandon leak-prone gas pipes and pursue non-pipe alternatives	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIE DPUC + PUC	Evaluate whether replacement is consistent with climate mandates
Pursue hydrogen demonstration projects in coordination with the Northeast Regional Hydrogen Hub	Creates opportunities for decarbonization of hard to electrify areas, such as high-heat industrial processes	State of RI, led by OER; Northeast Hydrogen Hub state and private sector partners	Technology research and development, workforce development, zoning, codes, safety regulations
Continue to pursue solutions to reduce emissions from solid waste	Lowers direct emissions from waste, creates source of renewable methane	OER in coordination with relevant waste facilities	Overlap with biofuels and biogas planning, ideally solid waste amounts decrease in future, consider implications on renewable gas supply
Future of the gas distribution system	Enables cost-effective decarbonization, planning, and aligning utility business model	PUC	Trimming branches of the distribution system where we can electrify, strengthening branches where we can't electrify
Begin developing a renewable thermal standard	Progressive scale down of thermal sector emissions	Legislature	Interplay of all different decarbonization technologies, cost effectiveness, jobs impacts, rethinking role of the utility

Prioritize Efficiency to Decrease Fuel Usage

The first way to reduce emissions from the thermal sector is to improve energy efficiency, so we use less fuel. This can be done by improving the efficiency of appliances and by improving the weatherization of buildings.

Continue Energy Efficiency Programs and Weatherization

Weatherization of buildings is key to ensuring a successful transition to decarbonized heating and cooling, because it helps to decrease our overall energy demand. While the utilities' efficiency programs support a number of weatherization programs and appliance efficiency standards, these should continue to be expanded.

Strategic Electrification

One pathway to thermal decarbonization is through strategic electrification. Converting thermal processes from fossil fuel power to energy efficient electric appliances can reduce emissions immediately. Air source heat pumps, for example, are three times more efficient at providing heat than fossil fuel heating systems, resulting in an immediate increase in fuel efficiency. The emissions of electric appliances for thermal processes will continue to decrease to zero, as we move toward the state's 100% Renewable Energy Standard by 2033.

Converting fossil fuel technologies to electric power will pose new challenges for our electric grid. According to the Heating Sector Transformation Report, 100% electrification of the thermal sector is not only unlikely, but also not cost effective.[84] Electrification is not appropriate for certain components of the thermal sector, such as high-heat industrial processes. Additionally, we must be cognizant of the impacts heat pump conversions will have on our electric distribution system. As we design incentives and other mechanisms to support the market for electrification, we need to remain strategic in how we plan for necessary changes to the electric system and simultaneously support other decarbonization technologies to reach our emissions reductions targets.

Target 15% penetration of energy efficient electric heating by 2030

A conversion of 15% of Rhode Island's buildings from fossil fuel heat to efficient electric heating by 2030 is an aggressive, but attainable and necessary target. This rate of conversion will reduce thermal sector emissions by an estimated 0.19MMTCO$_2$e[85]. While the market for efficient electric heating—including a variety of heat pump technologies—is relatively nascent in Rhode Island, the next several years will be used to build a strong foundation for the market to expand at a quicker pace in the last two decades as we approach 2050. The priority actions below, will help us reach this 15% target and plan for further expansion, in tandem with other decarbonized thermal technologies, post 2030.

Efficient heat pump incentives

There are several mechanisms for incentivizing efficient heat pumps that are expected to be used in the coming years. First, the Office of Energy Resources will be launching the High Efficiency Heat Pump Program (HHPP)[86] in 2023, which will combine federal funding from the American Rescue Plan Act (ARPA) with existing incentives provided by Rhode Island Energy's energy efficiency programs. The aim of the program is to create a robust incentive program, extending greater financial incentives to more Rhode Islanders who want to convert to efficient heat pumps. The program will also emphasize education

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[84] https://energy.ri.gov/heating-cooling/heating-sector-transformation

[85] Please see "Meeting our 2030 Mandate" and Acadia Center's Technical Appendix at the conclusion of this report for additional details.

[86] https://energy.ri.gov/heating-cooling/high-efficiency-heat-pump-program

and workforce development to build a sold market for this efficient, and ultimately emissions-free, thermal technology.

Second, the Inflation Reduction Act, recently passed by the U.S. Congress, will provide a suite of incentives including tax credits and rebate programs for heat pumps and other electric thermal appliances, such as induction stoves. The State will work diligently to ensure that the maximum benefits are easily accessible to Rhode Islanders and that federal incentives for heat pumps compliment State offerings.

Third, in the coming years, there will likely be opportunities through policy and regulation to identify long-term, sustainable funding sources for efficient electric heat that go beyond one-time federal stimulus funding. While federal funding can provide a very solid basis for standing up efficient electric heating programs, there may be a need to craft novel funding mechanisms that can carry electrification efforts well into the future.

Pursue district geothermal

District geothermal systems are being piloted in neighboring states as a solution for providing extremely efficient electric-powered heating and cooling that is delivered by a thermal utility company. Traditionally, gas utilities have delivered fossil fuel to customers connected to the gas distribution system to fuel heating appliances. Geothermal systems (a.k.a. ground source heat pumps) use the least amount of energy to deliver space heating and cooling, of all the electric thermal technologies currently available. Drawbacks to geothermal include high upfront costs, and disruptive installation practices, which involve drilling, and/or laying pipe in the ground or a body of water. Once geothermal systems are installed though, they have an extremely long lifespan and very low operating costs—providing clean, affordable, and reliable heating and cooling to customers.

The challenges with geothermal systems make it difficult for many homeowners to install these systems themselves; gas utilities, however, are uniquely well-positioned to carry the high upfront costs and engineering challenges given their experience with large scale infrastructure projects. In the next 1-3 years, OER will work together with the utility to assess the opportunities for district geothermal.

Decarbonized Fuels

Priority actions in this category mainly focus on using lower emissions fuels and using them more efficiently, but also contain actions to consume less fuel, by avoiding emissions caused by wasted fuel.

Increase biofuel blending in accordance with the 2021 Biofuel Heating Oil Act

The 2021 Biofuel Heating Oil Act requires that, by 2030, all No. 2 distillate heating oil sold in Rhode Island, "shall at a minimum meet the standards for B50 biodiesel blend and/or renewable hydrocarbon diesel."[87] This means that by 2050 all heating oil in the state will contain at least 50% biodiesel, significantly decreasing the carbon intensity of home heating oil.

As the state moves incrementally toward the 2030 biofuel mandate, it will be necessary to consider the impacts on customers, heating oil companies, and emissions. In the next two to three years, as biodiesel blending mandates increase, it will be important to anticipate and monitor potential implications of using higher biodiesel blends with existing heating equipment. Generally, biodiesel is considered a "like-for-like" swap with heating oil, because it can be used with existing oil boilers and furnaces. There are, however, concerns that higher biodiesel blends can wear on existing heating systems and may require retrofits.

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[87] http://webserver.rilin.state.ri.us/BillText/BillText21/HouseText21/H5132A.pdf p. 3

Additionally, in the next two to three years, compliance plans for the mandate should be made. Currently, there is no robust system for monitoring compliance with the blending mandate, nor are there requirements for biodiesel feedstocks and sourcing, both of which greatly impact the emissions profile of biodiesel. At this time, there is a very limited supply of bio-based fuels and in the context of significantly increasing global demand, future biodiesel prices are a concern. Therefore, we must consider strategies for mitigating the impacts of supply-side cost increases on local business.

While biodiesel has fewer greenhouse gas emissions than fossil diesel, using biodiesel and other bio-based fuels for heating still results in emissions. Biodiesel and other biofuels have a wide range of potential feedstocks, and numerous additional supply chain factors impact the emissions intensity of biodiesel. In order to effectively track our state's emissions, it will be necessary to understand the different emissions profiles of biodiesel and require biodiesel blending with the lowest emissions. Beyond the 2030 biodiesel blending mandate, there will need to be solutions for fully decarbonizing oil heating by 2050.

Continue to abandon leak-prone gas pipes and pursue non-pipe alternatives

Public Utilities Commission Docket No. 5210, "National Grid's FY 2023 Gas Infrastructure, Safety and Reliability (ISR) Plan," contains the Leak Prone Pipe Replacement Program which replaces leak-prone gas mains throughout the Rhode Island gas distribution network. Since the program's beginning in 2012, 537 miles of leak-prone pipe have been replaced and an additional 951 miles are expected to be completed by the program's end in 2035.

While the avoidance of methane leaks along the gas system is extremely important to reducing our state's emissions, the efficacy of the Leak Prone Pipe Replacement Program, in light of the goals of the Act on Climate, needs to be evaluated. Gas mains that are replaced through this program have an expected lifespan between 50-100 years, locking in gas infrastructure well beyond the target date for an emissions-free state. Currently, there are extremely limited supplies of decarbonized gases, and the ratepayer cost impacts of future decarbonized gas supplies must be considered. It would be imprudent to continue to reinforce and expand gas infrastructure that could not be easily and affordably decarbonized by 2050. Therefore, in the coming years, more emphasis should be placed on non-pipes alternatives (NPA). NPA seeks alternative ways of providing thermal service to Rhode Islanders, rather than expanding and enforcing the fossil gas network. The gas utility has already formed a working group to discuss developments in NPA.

Continue to pursue solutions to reduce emissions from solid waste

Waste streams, such as landfills and water treatment facilities, produce highly penetrative greenhouse gases that result from the breakdown of biological material. If not captured, these greenhouse gases are released directly into the atmosphere and contribute to global warming. One method of decreasing direct emissions from waste is to capture these gases and use them as a source of renewable gas.

The future of the state's solid waste streams should be considered in the context of thermal decarbonization opportunities as well. There are numerous technologies that could be explored, but the climate and environment impacts must also be critically examined.

Future of the gas distribution system

Just over half of Rhode Islanders are connected to the gas system for heating, cooking, and various other household appliances. Gas is also used for high-heat industrial processes. At this time, Rhode Island is supplied with fossil gas that, while cleaner than other fossil fuels like oil and coal, still emits greenhouse gases and contributes substantially to climate change. The gas system in Rhode Island relies on extensive physical infrastructure in the form of pipelines and supporting facilities. Pipelines and other gas infrastructure have been, and continue to be, built with decades to centuries-long time horizons. There is an urgent need to reconsider the existing gas infrastructure and planning in our state to avoid burdening consumers with the cost of stranded fossil gas assets, as the state transitions to carbon neutrality.

In August 2022 the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG, "Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate."[88] This docket will serve as an important first step in beginning to plan for the gas system's transition to carbon neutrality. There are many options for decarbonizing the thermal sector, and as the HST Report notes, it is unlikely that one single technology will prevail. Instead, to optimize costs and emissions reductions, a mix of solutions will need to be pursued. Other states are looking to transform their gas systems to work cohesively with a mix of decarbonized thermal technologies. In light of the Act on Climate, it will be important to engage in a very robust planning process that ensures a viable future for the thermal sector with a mix of different technologies. The utility company is uniquely positioned to tackle large decarbonization challenges and substantially help move the state toward our emissions reduction goals.

Begin developing a renewable thermal standard

Similar to the recently enacted 100% Renewable Energy Standard, the state should begin to plan for a renewable thermal standard to phase thermal emissions down at intervals that align with the Act on Climate Mandates. The results of Docket 22-01-NG "The Future of Gas" may provide a good foundation to begin planning for such a standard. Additionally, other states with drafted renewable thermal standards could be looked to for best practices and guidance.

Table X. Summary of Remaining Recommendations for the Thermal Sector from Select Recent and Relevant Studies

Report Title	
Status	Recommendation
Heating Sector Transformation Report	
Priority action[89]	Ensure: Increase efficiency and reduce carbon content of all fuels to zero over time – ensures progress no matter which technologies are used
Priority actions[90]	Learn: Data collection, R&D, pilot projects to understand technologies, infrastructure, and customers
Underway[91]	Inform: Educate stakeholders – customers, installers, policy-makers – about pros and cons of options, system interactions, etc.
Priority Action[92]	Enable: Facilitate deployment with incentives; target natural investment opportunities; align regulation, rules, codes; expand workforce
Priority Action[93]	Plan: Expand planning horizon; develop long-term, high-level contingency plans now (don't commit yet) and use to guide near-term policy

[88] https://ripuc.ri.gov/Docket-22-01-NG

[89] Our priority action to begin the development of a renewable thermal standards is responsive to this recommendation.

[90] Two priority actions are responsive to this recommendation: pursue district geothermal, and pursue hydrogen demonstration projects in coordination with the Northeast Regional Hydrogen Hub.

[91] This recommendation is central to all new and upcoming thermal policies led by OER. For example, the High-efficiency Heat Pump Program will have a consumer and workforce education component.

[92] Priority actions to incentivize heat pumps, the future of gas docket, and planning for the renewable thermal standard are responsive to this recommendation.

[93] Future of gas docket and planning for the renewable thermal standard are priority actions responsive to this recommendation.

Energy Efficiency Market Potential Study	
Underway[94]	Electrifying oil and propane-based systems offers the bulk of the economic opportunity for heating electrification.

Climate and Food Systems

A food system represents the interconnected parts of the food supply chain such as production, consumption, distribution, processing, consumption and disposal, all of which creates greenhouse gas emissions and significantly impacts water resources and biodiversity. Globally, the food and agriculture sector are responsible for one-third of greenhouse gas emissions [95] 70% of water withdrawals and 60% of biodiversity loss. At the same time, climate change threatens our long-term food security due to greater frequency of extreme and erratic weather events which impact crop yield, disrupt natural ecosystems and weaken national and global food supply chains.

The majority of food-related GHG emissions comes from agriculture and land-use such as methane from cattle production, nitrous oxide from fertilizers on crop production and carbon dioxide from clear-cutting for food production as well as refrigeration and management of food waste. Despite all of those impacts and high emissions, according to the EPA, one-third of food produced in the United States is never eaten and, food waste is the single most common material in landfills. When food is wasted all the resources, land, fertilizer, capital and energy that went into producing it is wasted, too. In RI, 20% of waste that goes to the Central Landfill is food and organics waste [96] (2017).

Fortunately, food systems and agriculture hold potential to sequester greenhouse gas emissions while regenerating biodiversity and ecological systems. In fact, according to "Project Drawdown" scientists and policymakers estimate that the top two solutions to staying below the critical 2 degrees Celsius necessary for survival are reducing food waste and eating plant-rich diets [97].

In order to better understand the impacts of climate change on our food systems, the following actions should be considered:

1. Establish metrics to set a baseline of GHG emissions derived from the food system throughout the value-chain from agriculture/aquaculture to manufacturing, processing, consumption and food waste disposal. The EPA's GHG emissions by economic sector fails to capture the complexity of food systems-related emissions which is why it is imperative that we better align climate, land-use, transportation, and food systems planning and policies in Rhode Island. Most of the emissions related to food consumption are derived from activities outside of the state because we import some 95% of the food we consume. However, these Scope 3 emissions[98] will

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[94] Current and upcoming heat pump incentive programs sponsored by OER and RIE incentivize the switch from oil and propane heating to efficient electric heat pumps.
[95] Cippa, Solazzo et al. *Nature* (2021)
[96] RI Food Policy Council (2017)
[97] Project Drawdown (2022)
[98] Scope 3 emissions are defined by the USEPA: "Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain. Scope 3 emissions include all sources not within an organization's scope 1 and 2 boundary. The scope 3 emissions

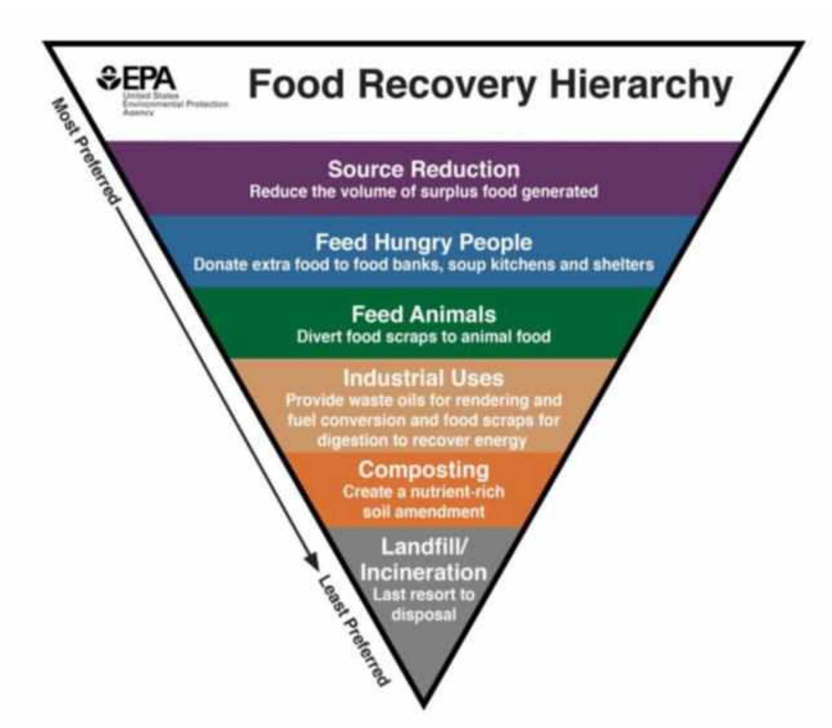
provide the greatest opportunity to drawdown emissions and should be considered as part of the Act on Climate mandates (ex: emissions related to the food purchased by State agencies for corrections and K-12 school meals could be quantified and goals could be set to shift menus towards more climate-friendly, nature positive foods for a healthy planet and healthy people)

2. Quantify the current and potential carbon sequestration of our working lands and waters (e.g. agricultural lands, coastal areas zoned for aquaculture, etc.)

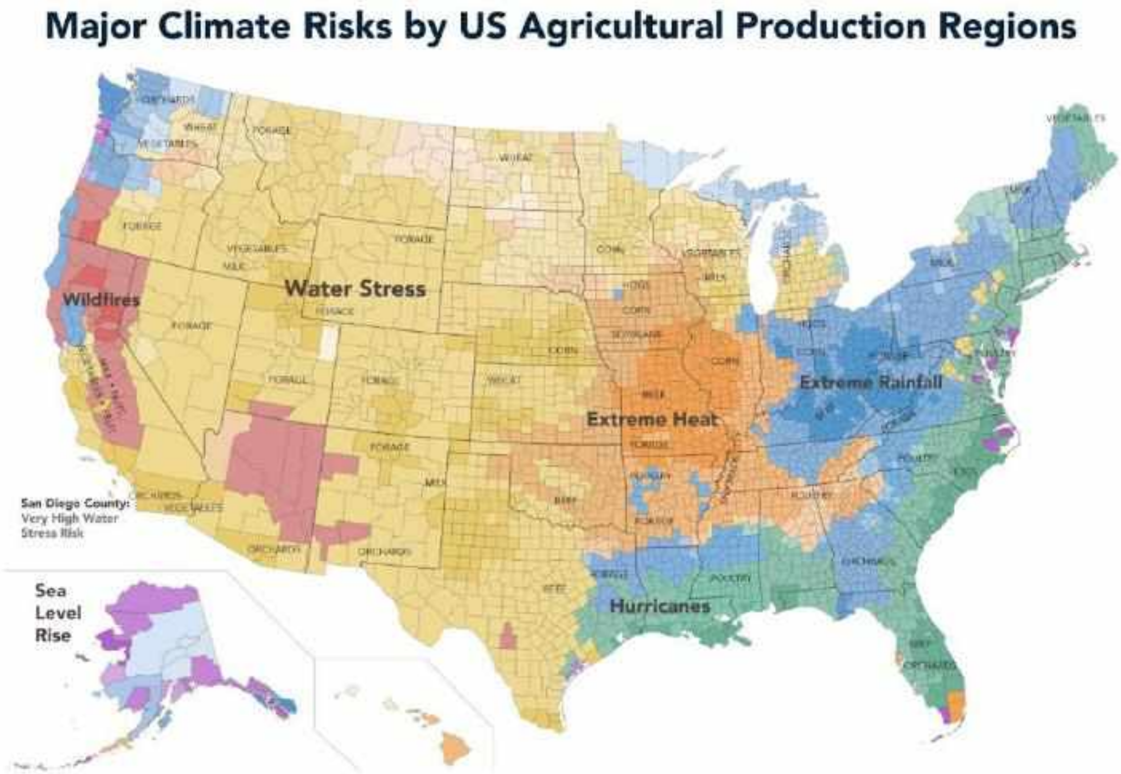
3. Evaluate policies for increasing food waste diversion and food recovery including more supports to help commercial waste generators comply with the 2017 "Food Waste Ban" and support municipalities with residential food/compost collection.

4. Support the development of the state's update to the 2017 food strategy "Relish Rhody" in order to strengthen regional food supply chains to better combat climate change disruptions to food producing and regions outside of New England

5. Explore alternative pathways to decarbonization which minimize trade-offs between renewable energy production and regional food production and harvesting.



for one organization are the scope 1 and 2 emissions of another organization. Scope 3 emissions, also referred to as value chain emissions, often represent the majority of an organization's total GHG emissions.



Source: *Every Country Has Its Own Climate Risks. What's Yours?*
https://www.nytimes.com/interactive/2021/01/28/opinion/climate-change-risks-by-country.html (2021)

Priority Actions to Address Climate Justice

As highlighted earlier in this report, since 2016, we've collectively seen vast growth in understanding about equity generally and climate justice specifically. This understanding should have already been a priority, and our level of understanding today is still deficient. However, we are making some progress. While the 2016 Plan omits mention of equity or justice, we have centered these concepts in the recommendations stemming from our more recent studies and we will integrate explicit consideration of equity and justice not only in this report, but throughout development of all future climate strategies and activities of the RIEC4.

In direct response to needs and calls for accountability, RIDEM and OER onboarded new staff in the fall of 2022 who will assist each respective organization to better understand and incorporate the needs of overburdened and underserved populations across the state. Bringing these voices to the front of the many conversations happening about mitigation and resilience will help to address community needs, build trust and incorporate new perspectives into Rhode Island's fight against climate change. This work began in 2022 with an inaugural 'Climate Justice Hour' in November 2022 with additional sessions planned in 2023 and beyond.

TABLE X: Summary of Priority Actions for Centering Climate Justice

Action	Impact
Create space for meaningful conversation – continue climate justice conversations in communities and with a new climate justice advisory board	Raises up new voices about climate justice and community needs into the RIEC4 and future climate plans, programs and policies
Better align work of RI's Health Equity Zones (HEZs) with the resilience and mitigation work being undertaken by RIEC4 agencies	Strengthens the efforts of the various HEZs to serve its members and provide tangible community benefits on issues related to climate change
Better coordinate state and local investments in urban tree programs	Provides health, social and environmental benefits for urban communities; increased tree canopies in RI's urban core
Provide technical assistance to communities for climate related issues	Allows communities to better address the climate/environmental/energy issues they have defined as priorities
Promote research into the impacts of climate change on overburdened and underserved communities	Provides a clearer understanding of direct impacts; better alignment of funding to address climate impacts and improve community resilience

Priority Actions Related to Land Use

Plants on our lands and in our oceans can absorb carbon dioxide, acting as a sink for emissions. However, removing natural elements of our land to develop our built environment (for roads, renewable energy resources and other uses) can take away the land's ability to sequester carbon dioxide. Beyond impacts on emissions – or climate change *mitigation* – how we use our lands is of critical importance in relation to climate change *adaptation* – our ability to reduce damages from and recover from the impacts of climate change like intense storms, extreme heat, and flooding.

These critical issues are being debated in RI, regionally in many states' climate plans and internationally. The Intergovernmental Panel on Climate Change (IPCC) published its Special Report on Climate Change and Land in August 2019[99]. It analyzes the existing science to date on how greenhouse gases are released and absorbed by land-based ecosystems, and the science on land use and sustainable land management in relation to climate change adaptation and mitigation, desertification, land degradation and food security. The findings are of great importance to decision-makers across the US and the world.

In terms of climate justice and equity, the way we use our lands will have a much bigger impact on the quality of life of Rhode Islanders than most other emissions reduction strategies. Land use policies that increase access to open public spaces and encourage the development of healthy communities while promoting the development of renewable energy resources is a balancing act RI must continue to explore in future legislation, regulation and policies.

[99] IPCC Report on Climate Change and Land Use (2019) https://www.ipcc.ch/srccl/

TABLE X: Summary of Priority Actions for Land Use

Action	Impact
Explore improvements to siting guidance and incentives that push solar development away from forests and agricultural lands towards previously disturbed sites	Streamline support for investments in renewable projects that minimize impacts on forest and agricultural lands
Identify a more stable and predictable funding stream for land conservation	Allow the state/municipalities/land trusts to develop longer-term land use protection strategies
Coordinate state and local investments in urban tree programs	Health, social and environmental benefits for urban communities
Expand existing programs that promote local agriculture	Increased local food security; reduce the carbon intensity of food
Promote research and policies that invest in regenerative agriculture practices	Allows agricultural lands to store more carbon to help mitigate the effects of climate change

Climate and Health

Climate change, health, and equity are inherently intertwined. Climate change acts as a risk multiplier, meaning vulnerable populations face more of its effects. Many of the environmental and social determinants of health, such as housing, proximity to traffic, tree canopy cover, and vulnerability to flooding, are related to climate. For this reason, improving community resilience is a key strategy to help keep a focus on equity and environmental justice. As incidences of heat-waves and flooding increase, we must address immediate health impacts and build resilience among Rhode Islanders.

Climate Change worsens the health effects from urban heat, flooding, severe weather and sea level rise, food and water borne diseases, vector-borne diseases, and poor air quality. Our efforts to cut greenhouse gasses, plant trees, reduce air pollution, build green infrastructure, and support healthy food systems will create huge gains in public health across the state. When we focus this work with equity and justice in mind, we will see the biggest gains among our most vulnerable populations. We should also use our decarbonization efforts to undo past harms and ensure that our youth are poised to take on the challenges of the work we know we need to do in our communities.

Extreme Heat

Extreme heat is an increasing threat across Rhode Island as the average temperature has already risen three degrees in the last century. Since 1980, there has been an average of 10 days above 90 degrees in the Providence area each summer, but already in the last several years, we have seen closer to 20 days. Extreme heat is the leading cause of weather-related injury and can lead to health harms such as cardiovascular events and dehydration. In the Providence area, studies have shown that some neighborhoods can be up to 12 degrees warmer on hot summer days. These neighborhoods also tend to stay warmer at night. In the last several years, the Department of Health (DOH) and the Department of Environmental Management (DEM) have teamed up to support urban forestry and better understand urban tree canopy across our cities.

Air Quality

Air quality also degrades when it is hot. Ozone is formed from air pollution and sunlight on hot days. While DEM measures air pollution and issues air quality alerts on high ozone days, it is the very localized, everyday emissions that we also must consider. For example, many schools and neighborhoods are close to heavy traffic and truck routes putting residents and children at a higher risk. Schools also lack proper air filtration and air conditioning creating poor indoor air quality. As spring and fall warms, learning suffers in hot classrooms. Asthma is also a large driver of school absenteeism and can affect learning. As we remove fossil-fuel burning appliances from homes and provide efficient air conditioning to urban families, the health of children will greatly improve as will their success in school.

Emergencies

During emergencies, people who are already vulnerable suffer the most. RIDOH has worked with senior living facilities to make sure they have shelter-in-place plans for their residents and adequate supplies during events. The Rhode Island Special Needs Registry allows those who need additional help to make sure they are prioritized during a storm. Restoration of power for those who need electricity for medical reasons is prioritized, but more can be done to help folks with assistance for back-up power and batteries for their medical devices. RIDOH is also working on supporting cooling shelters and community spaces that can serve as information centers and gathering places.

Mental Health

Mental health is affected by climate change in multiple ways. People who are taking certain medications are more prone to heat stroke and have a hard time regulating body temperature. Heat can also increase anxiety and levels of violence and can affect sleep and mental functioning. Extreme weather events also increase anxiety and can lead to post-traumatic stress when lives are disrupted. Working with communities on building social cohesion and supporting a local resilient economy can help people bounce back from disturbances faster. Working with youth on climate solutions lowers their sense of anxiety and gives them a place to be part of the conversation.

Health Care

The health care system should be an important part of implementing climate change solutions. Doctors and other health care providers are becoming more attuned to the effects of climate change on their patients. Medical students are asking to have climate change taught in medical school. Many health care systems are focusing on social determinants of health, the environment being one of them. The medical system also produces a large amount of waste and uses a large amount of energy. Hospitals should be part of the conversation about electrification and decarbonization as they provide critical community services. Sustainability efforts at hospitals are being supported more and more by medical professionals and should be part of state-wide efforts.

Looking Ahead to the 2025 Climate Strategy

When the legislature passed the Act on Climate and it was signed by Governor McKee in April of 2021, the sense of urgency for the State's response to climate change increased dramatically. Goals became enforceable mandates and clear priorities were set for equity, justice, and workforce development. These priorities were to be central to all our work on reducing emissions. Regular reporting, metrics, and dashboards, as well as strategic plans were required to ensure we stayed on track to meet our goals and clearly communicate status and progress. The *2022 Update* is the first of the plans required by the Act on Climate.

Beginning in September 2021, the RIEC4 initiated a comprehensive public involvement strategy to provide transparency and opportunities for engagement on the development of the *2022 Update*. The RIEC4 met more often – bimonthly versus quarterly – and held meetings across the state to allow more Rhode Islanders to participate in critical conversations about climate change. The RIEC4 held over 20 public listening sessions and workshops to gather public input for the *2022 Update*. The RIEC4 also worked closely with Governor McKee to make appointments to both the RIEC4 Advisory Board and the Science and Technical Advisory Board, started work to create a Climate Justice Advisory Group, and OER and DEM have both onboarded additional staff to assist with the state's numerous climate programs, including staff members in both agencies focused on climate justice. This *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead. We have reviewed the 2016 plan, reflected on the substantial work that has been done in Rhode Island over the past six years, and provided an interim path forward based on work being done across state government.

Much has changed in the world, the country, the region, and Rhode Island with respect to attitudes, actions, and science related to climate change since 2016. Key changes since 2016 include new emissions reduction targets directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate, in hope these priorities will be well established by 2025. The 2025 Climate Strategy will then build out workplans for each sector to meet our mandates and set us on a viable path to reach net-zero emissions by 2050.

During the dialogs with stakeholders, it became clear that the development of the *2022 Update* was also an opportunity to reconsider and confirm technical aspects of modeling. Current emissions inventory processes, methodologies, and tools were reviewed in detail and, in many cases updated and modernized to use better local data. We also include explicit actionable recommendations for additional analysis in support of the development of the 2025 Climate Strategy.

In terms of progress and where we stand, Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Since 2016, the State has conducted several in-depth studies deepening our understanding of decarbonization activities and enabling actions. The *2022 Update* includes a list and summary of over a dozen major studies that either directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning. The list of studies in the *2022 Update* is not complete but is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy.

Additionally, the Rhode Island General Assembly has debated and passed several bills addressing different aspects of our response to climate change. The most significant legislation was the 2021 Act on Climate, which set statewide, economy-wide climate goals that are both mandatory and enforceable.

In 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil.

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2022, the RI legislature passed a bill, subsequently signed by Governor McKee, to commit the state to 100% renewable energy by 2033.

In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. In 2022, the legislature authorized procurement of up to an additional 1000 MW of power generated from offshore wind.

Obviously, action is needed to meet the upcoming emissions reduction targets that are now enacted in Rhode Island law. While the details, modeling, and balancing of these actions across the sectors of our economy will be done as part of the 2025 Strategic Plan, many actions are underway by several agencies, funded by both federal grants and state investments, and they must continue.

In the electric sector, we must take action to both consume less electricity and meet electricity needs using decarbonized energy resources. Critical to this will be meeting the 100% Renewable Energy Standard by 2033. The 100% Renewable Energy Standard is expected to grow demand for renewable energy resources; this, in turn, will require strategic investments in our electric grid to enable timely and efficient integration of these resources, as well as bolstering cost effective renewable energy within Rhode Island's portfolio through procurement of offshore wind. All actions must be considered within the larger fabric of policy objectives, and should be refined to improve affordability, equity, land use, and other policy objectives. This report outlines seven priority policies and actions for the electric sector to meet our goals and more detailed options, plans, and metrics will be developed as part of the 2025 Strategic Plan. Upcoming discussions on the use of smart meters and modernization of our electric grid will be critical to formulate state policies and investments moving forward.

In the transportation sector, priority actions must be taken to both consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Critical to all this is the development and construction of a convenient and robust charging infrastructure across Rhode Island and pushing the adoption of more and more low-emission and zero-emission electric vehicles. Strategies outlined in the *2022 Update* those focusing on passenger vehicles, public transportation, and school bus transportation. More work is needed to develop a plan for commercial fleet conversion. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions in transportation infrastructure and take action to incentivize lower-emissions mobility. The modeling to done in support of the 2025 Strategic plan will balance these options and provide us with the degree of implementation and penetration needed to meet our goals.

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island. Our initial action on this will be a large state investment supporting the conversion of heating systems to heat pumps, moving from fossil-fuel based heating to electricity. An upcoming discussion on the future of natural gas in Rhode Island will also be very important to inform our strategies and plans for the building and heating sector. As Rhode Island makes significant investments in both housing and school construction, climate considerations must be incorporated into those design and construction plans.

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with the Rocky Mountain Institute (RMI) and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by the Acadia Center utilizing the RMI's Energy Policy Simulator (EPS). By modeling a short list of key policy scenarios as outlined in the report, it is projected that Rhode Island slightly misses the Act on Climate's 2030 reduction mandate. This is a very simple, preliminary model that verifies Rhode Island is moving in the right direction but is not quite at the point where we can be confident in our success. More scenarios must be considered, with input from a wide variety or experts and stakeholders, and the modeling needs to be further refined to develop and balance different implementation strategies to increase that confidence. That will be the crux of the 2025 Strategic Plan.

On that note, the RIEC4 will immediately turn attention to the 2025 Climate Strategy, which will include a set of "strategies, programs, and actions to meet economy-wide enforceable targets for greenhouse gas emissions" due by December 31, 2025. The 2025 Climate Strategy will be developed via a robust stakeholder process modelled closely on the process used for the *2022 Update* and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The 2025 Climate Strategy will be a comprehensive working document that will be updated every five years thereafter.

The public involvement strategies for the *2022 Update* were generally well received and effective in soliciting comments and feedback from a broad range of stakeholders. Thank you to everyone who participated in the listening sessions, attending our RIEC4 meetings, and for providing comment through the online portal. A huge change from 2016 is the degree of public engagement and interest, and it is clear that people want more - both in terms of more opportunities to participate and more action. Looking forward to starting the next process on developing the 2025 Strategic Plan, we will continue some of the best practices from this effort with a specific eye towards bringing in more voices to the conversation. In particular, our engagement with disadvantaged and underserved communities has just begun and there is much more work necessary to ensure that those voices are heard in our policy and program discussions. Similarly, we need to develop systems to effectively engage with municipalities and Rhode Island's business communities. Their voices and contributions will also be critical to meeting our greenhouse gas emissions reduction goals. Concurrently with these additional outreach efforts, we must expand our communications channels to effectively tell our story and get broader engagement across the State.

The agencies in the RIEC4 will focus on implementation of the action items outlined in this report. The RIEC4 will continue to work with the Advisory Board, as well as the Science and Technical Advisory

Board and Climate Justice working group, to refine policies and develop metrics and the public dashboard called for in the Act. The metrics and dashboard will show the progress made and the status of our efforts.

Discussions of identifying and allocating resources to these efforts will continue. The decarbonization and transition of our economy must be done carefully, and deliberately, to meet the goals set forth in the statutes. This will require both internal and external expertise and support for all the agencies. In the near term, prospects for federal support in many areas looks strong, particularly from the federal Bi-Partisan Infrastructure Law and the Inflation Reduction Act. However, these federal funds will not provide complete support needed for our efforts and state funds will be needed.

We look forward with enthusiasm to working with all partners as we chart our path forward to implementing solutions and achieving the goals of the Act on Climate.

Appendix: Stakeholder Engagement

Summary

A goal from the outset of the development of this report was to prioritize stakeholder involvement to inform the priorities and actions outlined for next steps to meet the goals of the Act on Climate. Over the course of 12-months between November 2021 and November 2022, over 20 listening sessions and workshops addressed the following topics, and in many instances multiple sessions were hosted for each topic:

1. Scoping the *2022 Update*
2. How to Define Net-Zero Emissions by 2050
3. Understanding RI's Greenhouse Gas Inventory Process
4. Priority Actions for the Electric Sector
5. Priority Actions for the Transportation Sector
6. Priority Actions for the Thermal Sector
7. Priority Actions for Land Use
8. Health & Climate
9. Buildings & Climate
10. Food Systems & Climate
11. Climate Justice

The first seven sessions listed above are further summarized in the following pages of this appendix. We highlight issues heard from participants and actions identified to help the state meet its near-term climate goals.

In addition, we further highlight the issues of health and climate, buildings and climate, food systems and climate, and climate justice in special sections in the report. A copy of the slides from these sessions can be found online at: https://climatechange.ri.gov/act-climate/attend-event [100]

Throughout the development of this report, the RIEC4 utilized an online comment portal called Smart Comment to collect and review additional comments submitted by interested parties. Over 390 sets of comments were received from November 2021 through early December 2022. The vast majority were submitted on behalf of individuals, with additional sets of comments submitted on behalf of local/regional organizations active in RI's climate change conversation. Additional public comments were offered verbally at RIEC4 meetings between December 2021 and December 2022.

[100] Note: The November 'Climate Justice Hour' did not utilize slides. It was intended to be a conversational session. Additional 'Climate Justice Hours' will be held in 2023 and beyond to ensure continued conversations with communities disproportionately impacted by environmental and climate burdens.

Scoping the 2022 Update Sharing Session (#1) Stakeholder Appendix

The 1st series of public sharing sessions was held in November 2021 and discussed the scope of the *2022 Update to the 2016 Greenhouse Gas Emissions Reduction Plan*. During this first public sharing session, 89 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the clean energy industry.

The goal of the discussion was to reach consensus on the scope of the *2022 Update* and was framed by four discussion points to generate participation and input from all groups represented.

The first discussion point was for each attendee to describe their objectives for the update. After attendees expressed their opinions on the matter, the following objectives were recorded: be responsive to the 2021 Act on Climate, center equity and be developed using a meaningful public participation process, leverage lessons learned since 2016, build a foundation for the *2025 Climate Strategy*, reconsider and confirm technical aspects of modeling while promoting reliance and being action oriented, and focus on near-term actions to achieve the 2021 Act on Climate's 2030 mandate.

The next discussion point was focused on the major changes and lessons learned since the last Greenhouse Gas Emissions Reduction Plan was published in 2016. Some of the changes that were highlighted include new learning from analyses, reports, progress on actions, and advances in science, technology, and business over the last few years. There was also a mention of lessons learned from intense weather events that renewed a sense of urgency to act on the issues posed by the changing climate.

Given these objectives and changing conditions, attendees collaborated with one another to come up with updates to specific components of the *2016 Greenhouse Gas Emissions Reduction Plan*. This scope includes technical updates, updates to pathways, policy, and implementation strategies, as well as specific action items. The technical updates include modernizing the greenhouse gas emissions reduction targets to comply with the 2021 Act on Climate, defining the goal of reaching net zero emissions by 2050, and review modeling to ensure the 1990 baseline is sound and the data and modeling assumptions are reasonable. Under the update pathways, policy and implementation strategies, there were a few more recommendations. This included providing progress updates, as well as coordinating emissions sectors with policies from the *2016 Plan*, adding and refining policy and implementation strategies from more recent studies that also comply with the 2030 mandate, and consider new funding opportunities. There were also recommendations to review the entire *2016 plan* with equity appropriately centered, identify and engage key stakeholders, develop a climate dashboard that tracks progress on community-prioritized outcomes, and identify and address the prerequisite needs or the *2021 Climate Strategy* and preview the work ahead.

The last discussion point was centered around which stakeholder groups should be included in future conversations, and attendees were encouraged to help connect the project team to their contacts within these groups and to continue to recommend stakeholders with whom to engage.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Defining 'Net-Zero Emissions by 2050' Sharing Session (#2) Stakeholder Appendix

The 2nd series of public sharing sessions was held in January 2022 and discussed how the 2021 Act on Climate's ultimate mandate of 'net-zero emissions by 2050' should be defined. Over the span of two identical sessions, held on January 11th and 13th, 102 people participated from a range of stakeholders including, interested individuals, environmental advocates, policymakers, and representatives of the clean energy industry.

The scope of the discussion was framed by three different prompts whose aim was to increase understanding surrounding considerations and preferences for how we define 'net-zero by 2050'. This was facilitated through a brief background information discussion before diving into the prompts.

The first prompt asked attendees which emissions should be included when defining the term 'net-zero emissions by 2050'. Attendees generally supported continuing to track the same four greenhouse gases already tracked by the IPCC and US EPA, which include Carbon dioxide, Methane, Nitrous oxide, and Fluorinated gases. A few concerns were raised including timeframes regarding global warming potentials, biogenic versus anthropogenic emissions, tracking for methane leakage from pipelines, considerations for land use changes, emissions from biodiesel and bioheat, the importance of consistency throughout states and with the IPCC, the role of education and messaging, developing mitigation strategies tailored for each type of emission, and prioritizing action.

The second prompt was centered around how we should net emissions. There were two net options given, one was net each greenhouse gas first and the second was to net MMTCO2e last by subtracting the sinks from the sources of MMTCO2e. Attendees were a bit more divided in this discussion, but the overall preference was towards netting MMTCO2e last, which is the current practice and capability. Some considerations that were raised included but were not limited to understanding the consequences of offsets versus sinks, the role of transparency regarding climate dashboards, and definitions to account for changes in technology and science.

The third and final prompt encouraged attendees to discuss the timeframe over which emissions should be netted. The current practice is to net emissions over an annual timescale, but attendees debated over whether annual or sub annual time frames would be more beneficial. It was roughly split 50/50 with slightly more attendees supporting the current annual timeframe but made sure to raise important points regarding the potential value in supplementing annual netting with sub-annual netting and considering the best timeframe for each type of sector. Other considerations included prioritizing action, focusing on reaching short term mandates, prioritize mitigating sources, highlighting success stories in conjunction with quantitative metrics, and identifying impactful near-term actions.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Greenhouse Gas Inventory Methods and Tools Sharing Session (#3) Stakeholder Appendix

The 3rd series of public sharing sessions was held in March 2022 and discussed the different greenhouse gas inventory methods and tools. During the session, 76 people participated from a range of stakeholders including, interested individuals, environmental advocates, policymakers, several state administration representatives, and representatives of the clean energy industry.

There were three objectives of the discussion: (1) provide a tutorial to improve understanding of how we inventory greenhouse gas emissions, (2) understand considerations and preferences for how / when we re-estimate greenhouse gas emissions changes due to land use, land use change, and forestry, and (3) understanding preferences for comparing apples-to-apples across years versus maintain an unchanging baseline against which to compare contemporary emissions.

The sharing session began with RIDEM expert Allision Archambault presenting a brief overview of how RIDEM inventories greenhouse gas emissions. After the overview, a facilitated discussion took place, using two discussion prompts that were meant to help attendees understand considerations and preferences for updating greenhouse gas emissions accounting.

The first prompt asked attendees what considerations they saw for how frequently Rhode Island estimates emissions reductions due to land use, land use change, and forestry (LULUCF). Attendees generally supported estimating emissions from LULUCF every five years, which is in line with Rhode Island's Comprehensive Climate Strategy beginning in 2025. There were some suggestions, including working to better understand trends and changes in LULUCF emissions and accounting methodologies. In doing this, we might strategically estimate emissions from LULUCF when certain indicators are met. The second prompt encouraged attendees to discuss considerations for how frequently we update the 1990 baseline. Three considerations were given: the first was to never change the baseline, the second was to update somewhere in between / strategically, and the third was anytime updated science is available. The attendees generally recommended that re-estimation should occur whenever major updates to climate science occur, such as those identified in IPCC Assessment Reports. Another recommendation made includes consideration of administration burden and costs when determining the frequency of update estimations.

Finally, attendees had an opportunity to voice other considerations for greenhouse gas emissions inventorying. The first included reiterating the importance of accurate accounting of and reduction of methane emissions, specially from the gas pipeline system. The second consideration was whether and how we track 'Scope 3' emissions, which are the emissions that result from activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Electric Sector Sharing Session (#4) Stakeholder Appendix

The 4th series of public sharing sessions was held in April 2022 and discussed the priority actions for the Electric Sector with regards to the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan*. Over the span of three identical sessions, 58 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the electric sector.

There were three objectives of the discussion: (1) provide a refresher on key recommendations from the 2016 Plan and update with the most relevant recent reports, (2) brainstorm actions needed over the next 1-3 years to set Rhode Island on a path to meet the 2030 mandate, and (3) understand preferences and considerations to inform how actions are prioritized.

Dr. Gill provided significant background information Rhode Island's electric sector emissions and how emissions would change if Rhode Island went 100% renewable. Some progress that was described included the extension of Rhode Island's Least-Cost Procurement statute, expansion of appliance and equipment energy and water efficiency standards, costs versus benefits measurement of pathways to decarbonize the electric sector in *The Road to 100% Renewable Electricity by 2030 in Rhode Island*, and two programs offered through the Renewable Energy Fund called ConnectedSolutions and Solar+Storage Adder Pilot Program that support the development of energy storage systems. Following the background information, several policy and programmatic recommendations were made, as well as planning, enabling, and equity recommendations.

The attendees then participated in a facilitated discussion, which allowed them to express their opinions on priority actions needed over the next 1-3 years within the electric sector to aid Rhode Island in meeting its goals for the 2030 emissions reduction mandate. The framework that was used in this segment fell under three categories: ensure decarbonization, enable decarbonization, and refining our actions. One clear priority action is to pass a 100% Renewable Energy Standard, and attendees also recommended bolstering energy efficiency and demand response programs, encouraging, and educating renewable energy practices in preferred locations, continuing to improve building standards and codes, modernizing the electric grid, and deploying smart meters. Some refining actions that were suggested by the attendees include improving affordability, improving equitable access to programs and public participation in program design, balancing land use priorities, and ensuring equitable investments in communities. Actions that would enable this include building relationships between customers and utilities, programmatic and process evolution, building community partnerships through regional collaboration, and systematic planning for energy storage.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Transportation Sector Sharing Session (#5) Stakeholder Appendix

The 5th series of public sharing sessions was held in May 2022 and discussed priority actions for the transportation Sector with regards to the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan*. Over the span of three identical sessions, 54 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the transportation sector.

There were three objectives of the discussion: (1) provide a refresher on key recommendations from the 2016 Plan and update with the most relevant recent reports, (2) brainstorm actions needed over the next 1-3 years to set Rhode Island on a path to meet the 2030 mandate, and (3) understand preferences and considerations to inform how actions are prioritized.

Dr. Gill provided background information on the greenhouse gas emissions from the transportation sector and said that most of the emissions come from on-road vehicles, which was one of the main focuses of the discussion. She also noted that there is an overall reduction in the transportation sector when (1) we consume less fuel and (2) we consume lower-emissions fuels. These pathways are what framed the facilitated discussion later in the presentation. Dr. Gill also reviewed Rhode Island's efforts to decrease carbon emissions in the transportation sector and named a few key areas of progress: encouragement of electric vehicle use in the state, electrification of the public transport buses, and enacting more stringent air regulations. In relation to decarbonizing the transportation sector, Dr. Gill highlighted two key studies conducted since 2016 that provide meaningful templates and information for states to use. The *Clean Transportation and Mobility Innovation Report* and the more recent *Electrifying Transportation Report* both provided significant information on recommendations for creating a healthier environment through more updated an efficient transportation use.

The attendees then participated in a facilitated discussion, which allowed them to express their opinions on priority actions needed over the next 1-3 years within the transportation sector to aid Rhode Island in meeting its goals for the 2030 emissions reduction mandate. The framework that was used in this segment was split into two conversations consistent with the two pathways we must reduce emissions from the transportation sector: reducing fuel consumed, and consuming lower-emissions fuel. The priority actions included reducing high-emissions driving, increase low-emissions mobility, and refining our actions. To reduce high-emissions driving, attendees suggested making driving less attractive while making transit more attractive, consider lower-emissions biofuels, and enact stricter emissions regulations on vehicles. As a suggestion to increase low-emissions mobility, attendees recommended making active mobility more attractive, such as support for the Bicycle Master Plan. In terms of refining our actions, attendees suggested learning from others, as well as balancing climate impacts of transportation investments among other policy objectives such as safety. The second conversation prompted attendees to suggest priority actions to encourage electric vehicle usage as well as charging infrastructure availability. In terms of actions to encourage people to switch to electric vehicles, attendees suggested incentive programs with sustainable and substantial funding streams, as well as broadening incentive programs to include other modes or transportation such as e-bikes. Attendees also discussed requiring maintenance strategies and standards for charging stations for actions to expand electric vehicle charging. Finally, under the section titled "refining our actions" attendees recommended tailoring strategies based on use cases and needs, as well as integrating equity into program design.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Thermal Sector Sharing Session (#6) Stakeholder Appendix

The 6th series of public sharing sessions was held in June 2022 and discussed emissions reductions in the thermal sector. Over the span of three sessions, 47 people participated from a range of stakeholder groups including, interested individuals, environmental advocates, fuel sector advocates, policymakers, and representatives of the utility company. The scope of the discussion was framed by two guiding emissions reductions principles: to reduce our thermal sector emissions, we can, 1) consume less fuel, and 2) consume lower emissions fuel.

Throughout the three sharing sessions, stakeholders had a range of comments, including numerous ideas to both enhance existing mechanisms for thermal decarbonization and to push beyond current structures which would enable novel approaches to decarbonizing our thermal sector. Ideas for thermal decarbonization also loosely formed a timeline of when to pursue certain measures, starting with low-hanging fruit while simultaneously planning for larger-scale and more complex projects that are not yet feasible in the short term.

Building codes, workforce development, and the implications of various decarbonization pathways and regulatory frameworks on energy costs, were some of the most highly discussed topics. Numerous stakeholders see building codes as a powerful lever for lowering the carbon intensity of heating and cooling in buildings. Stakeholders would like to see stronger, more enforceable energy codes that require buildings to lower the amount of energy needed for heating and cooling, and to require technologies that will be carbon-free. Ensuring that Rhode Island has the labor force needed to construct and install technologies in buildings that meet ambitions efficiency standards and decarbonization standards is essential. Furthermore, stakeholders see a need to start planning for the emissions and price impacts of various decarbonization pathways that could be pursued. Several stakeholders argued that a mix of centralized and decentralized approaches will likely be needed to meet the Act on Climate mandates, and given the scale of these potential project ideas, and the significant potential impacts on costs to consumers, it is urgent to think about how to manage these scenarios.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Land Use Sharing Session (#7) Stakeholder Appendix

The 7th series of public sharing sessions was held in July 2022 and discussed how natural vegetation can absorb greenhouse gasses, resulting in lowering emissions, and how we use our land can also help adapt to a changing climate and build community resilience. Over the span of three sessions, 43 people participated from a range of stakeholder groups including, interested individuals, environmental advocates, land use advocates, policymakers and renewable energy. The scope of the discussion was framed by two guiding questions: what do we need to do to decrease emissions resulting from how we use and develop land? and; what do we need to do to increase the amount of carbon our land can sequester?

Throughout the three sharing sessions, stakeholders had numerous comments, including clarifying what policies are in place to reduce solar development of forests and agricultural land (e.g. redirecting solar development to previously disturbed sites), promoting transit-oriented development, adopting a no-net loss of forests policy, prioritizing forest management to increase sequestration, promoting reforestation, increasing available state funds for land protection (including agricultural lands), prioritizing urban trees, and the need for a broader state discussion to address competing land uses.

Solar development, no net-loss policies, agricultural land protection (including healthy sols), and forest conservation (both urban and rural) were some of the most highly discussed topics. Numerous stakeholders see the competition between renewable energy development and land conservation as one of the most pressing on-going discussions in Rhode Island related to climate change. Stakeholders would like to see more regulations and policies in place to prevent future forest loss. Several stakeholders argued that issues related to food security and organics diversion need to be considered as well.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Technical Appendix: Energy Policy Simulator GHG Emissions Avoided Modeling Analysis

Technical analysis conducted by Acadia Center, in collaboration with RIDEM, was used to inform the estimates of avoided greenhouse gas (GHG) emissions associated with individual actions and the collective suite of actions described in previous sections of this report. Specifically, Acadia Center leveraged the Rhode Island Energy Policy Simulator (EPS) model developed by Energy Innovation and RMI. The EPS was originally designed at a national scale with the intention of discovering the most effective policies to decarbonize America's economy at the lowest cost and empower decision makers to find the best course toward a low-carbon U.S. economy. In recent years, state-level versions of the EPS have been publicly released in select states. The version that has been customized for Rhode Island, referred to as the Rhode Island EPS (RI EPS), is scheduled to be released in early 2023 and will serve as a free, open-source, peer-reviewed model that allows users to estimate climate and energy policy impacts through 2050 on emissions, the economy, jobs, and public health using publicly available data. Technical documentation associated the EPS, detailing the specifics of how the model works, can be found at: https://us.energypolicy.solutions/docs/.

The RI EPS uses a "base year" starting point of 2020 and then projects emissions out to 2050 under a pre-loaded "Business as Usual" (BAU) scenario that incorporates existing policy, scheduled power plant retirements, some improvement in building and transportation efficiency, and economic adoption of electric vehicles (EVs). It's important to note that, due to some methodological differences, the base year 2020 GHG emissions in the RI EPS likely will not match the 2020 Rhode Island GHG emissions inventory (to be released in December 2023). For this reason, the RI EPS is not intended to provide precise projections of how a specific suite of actions will impact future emissions in Rhode Island as measured by the state's official GHG accounting standards, but rather is intended to provide high-level insight by estimating approximate GHG emissions reductions trajectories for the state.

Actions that have already been formally adopted in state legislation – including Rhode Island's Renewable Energy Standard and Biofuel Heating Oil Act – are included in this BAU Scenario. Building off of this BAU scenario, Acadia Center leveraged input and data from various Rhode Island state agencies to develop a customized emission modeling scenario for the *2022 Update* with the intent of developing high-level, preliminary estimates of the GHG emissions avoided by 2030 from both 1) Individual actions in this draft plan and 2) The collective suite of actions in this draft plan. Evaluating multiple policies simultaneously through the RI EPS captures the interactive effects of these policies. Ultimately, the 2022 Draft Climate Plan Update Scenario details how actions outlined in this plan would reduce Rhode Island's GHG emissions in 2030 beyond the reductions already captured in the BAU Scenario.

The table below provides a list of the actions analyzed for GHG emissions reduction potential by Acadia Center using the RI EPS and briefly describes the analysis approach for each action. In some instances, the analysis approach is "bottom up": For example, estimating vehicle miles travelled (VMT) avoided in the year 2030 as a result of the collective suite of actions and programs outlined in Transit Forward RI 2040 to reduce VMT in the state. In other instances, the analysis approach is "top down": For example, setting an aspirational target of 15% of space and water heating demand in all buildings served by efficient electric appliances by 2030. For "top down" measures, the specifics of the policies and programs needed to achieve these aspirational targets will require further detailed conversation and analysis.

Table X: List of Actions Analyzed in the Rhode Island Energy Policy Simulator "Customized Emission Modeling Scenario for the 2022 Update" & Analysis Approach by Action

Action	Analysis Approach
Enact a 100% Renewable Energy Standard	In accordance with the Renewable Energy Standard, assumes 72% of total electricity generated to be from qualifying renewable energy sources by 2030 (on course for 100% by 2033). This action was incorporated into the RI EPS BAU projections as the policy is already formally adopted in legislation.
Increase Adoption of Electric Vehicles (Light Duty)	Assumes state adopts Advanced Clean Cars II Regulations, taking effect starting model year 2027.
Increase Adoption of Electric Vehicles (Trucks)	Assumes state adopts Advanced Clean Trucks and Phase 2 GHG regulations, taking effect starting model year 2027.
Increase Decarbonization of RIPTA's Bus Fleet	Assumes 17.7% of total RIPTA bus fleet miles are driven by EVs by 2030 based on estimated projections from RIPTA staff assuming 1) Three pilot Proterra buses in service; 2) R Line electrification; 3) Electrification of five Newport routes; and 4) Route 78 service electrification.
Expand RIPTA Ridership to Reduce Light Duty VMT	Assumes a 4.8% reduction in statewide single occupancy vehicle miles travelled (VMT) below 2020 levels by 2030 based on estimated projections from RIPTA staff assuming 1) Full funding for TMP implementation; 2) Sufficient labor resources (drivers, mechanics, etc.) to implement at recommended service levels; 3) Timely implementation of all new routes and span/frequency recommendations; 4) Ridership growth at estimated rates; and 5) Land use changes consistent with TCRP calculator assumptions.
Strengthen Building Energy Codes	Assumes continuous adoption of the most recent International Energy Conservation Code (IEEC) model energy code for residential buildings and continuous adoption of the most recent American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Standard 90.1 for commercial buildings for all code cycles falling between 2021 and 2030.
Increase Efficient Electrification of Building Space and Water Heating	Assumes achievement of 15% of space and water heating demand in all buildings, both residential and commercial, in the state being provided by efficient electric appliances (e.g., heat pumps) by 2030.
Increase Biofuel Blending in Heating Oil	In accordance with the 2021 Biofuel Heating Oil Act, assumes that a percentage of biofuel is blended into the heating oil supply at rates of 15% by 2024, 20% by 2025, and 50% by 2030. In accordance with the current RI GHG emissions inventory lifecycle emissions associated with biofuel production and biofuel combustion were not assumed to result in GHG emissions attributable to Rhode Island. This action was incorporated into the RI EPS BAU projections as the policy is already formally adopted in legislation.
Maintain Current Amount of Forested Land	Assumes that Rhode Island adopts a policy or set of policies that results in maintaining the existing amount of total forested land currently in the state (approximately 361,000 acres) through the year 2030. This is an increase in amount of forested land in 2030 in comparison to the BAU Scenario which assumes a 2.3% decline in 2030 levels of forested land relative to 2020 levels of forested land based on analysis conducted by RIDEM.