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.

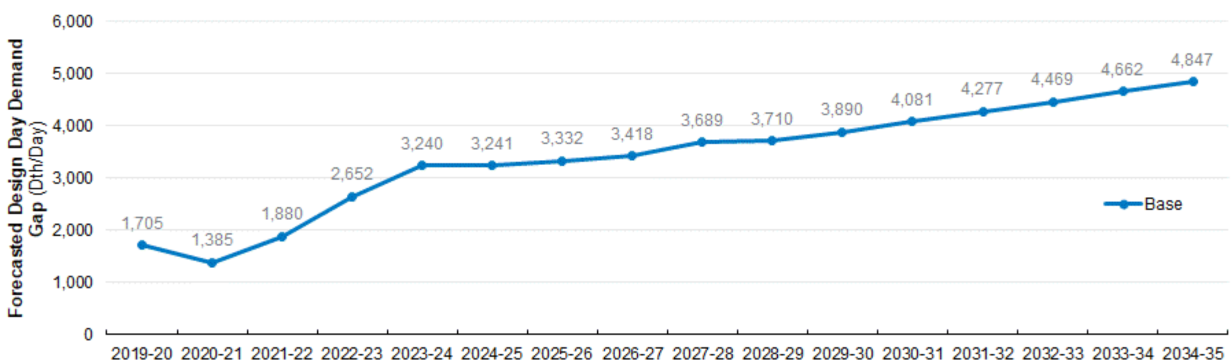
This change in approach effectively reduced the AGT capacity available to Aquidneck Island compared to the capacity available in the past. The lack of flexibility also created an immediate gas capacity constraint when projected demand is at its highest on the island under extreme cold conditions, including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

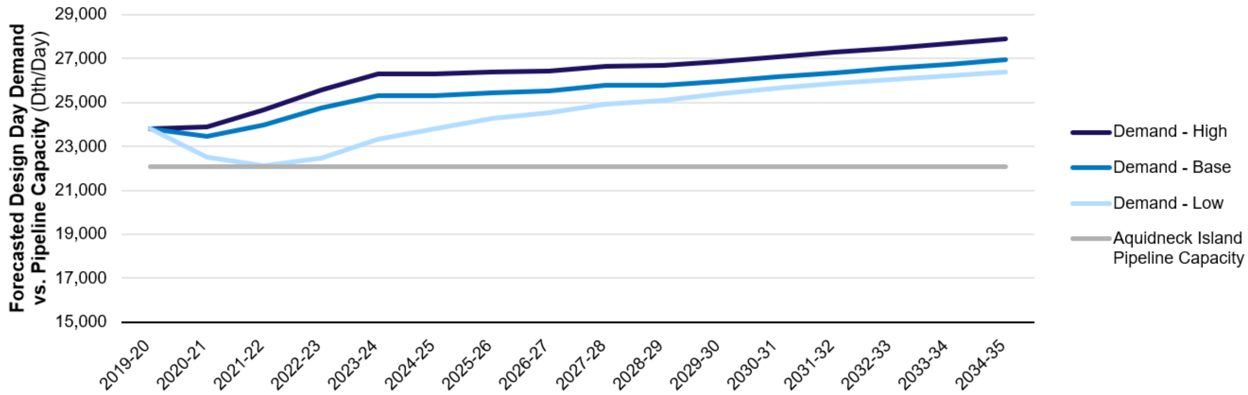
Rhode Island is a national leader in energy efficiency, ranked third in the nation in the most recent *2019 State Energy Efficiency Scorecard* report from the American Council for an Energy-Efficient Economy. The Company's long-term gas demand forecast reflects the effects of energy efficiency including 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.

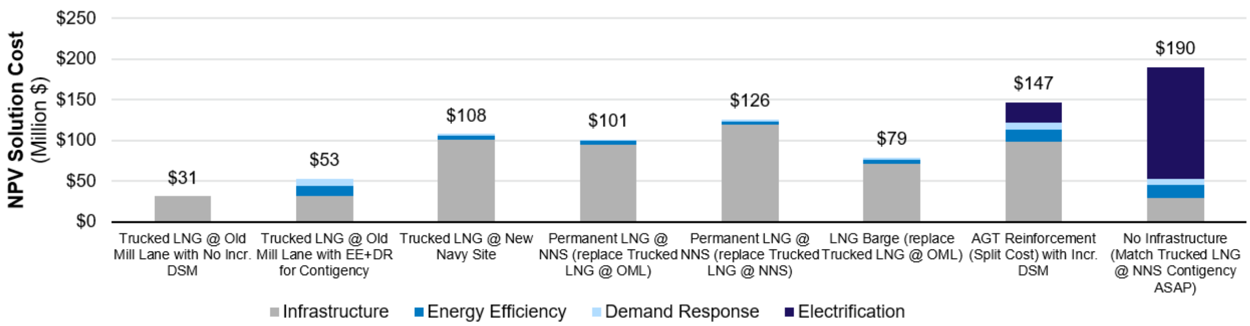
Figure 3 below presents the cumulative net present value (NPV) of estimated costs for the different approaches through the winter of 2034/35. For this cost analysis each of the infrastructure options has been paired with complementary incremental demand-side programs.[6]

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.

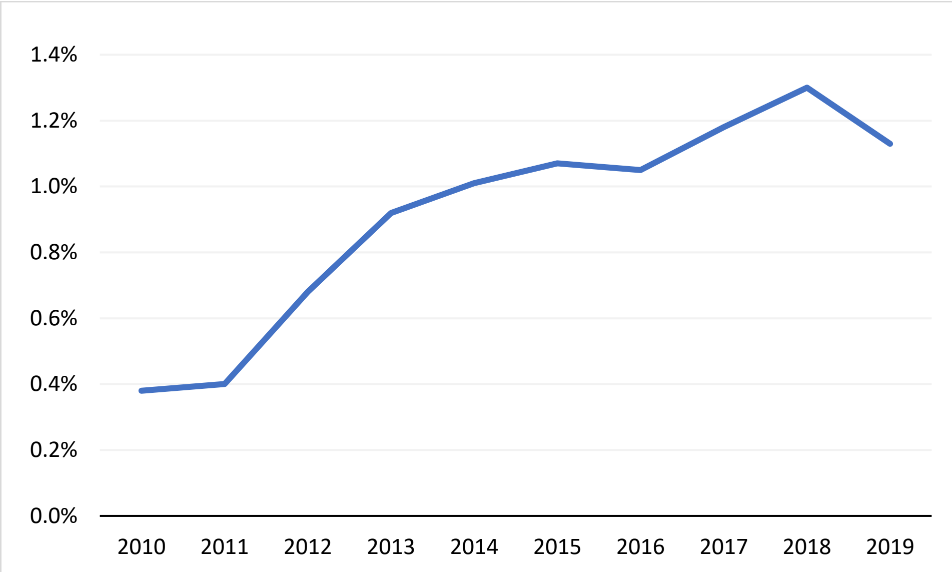
5. Projected Natural Gas Demand through 2034/35 on Aquidneck Island

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.

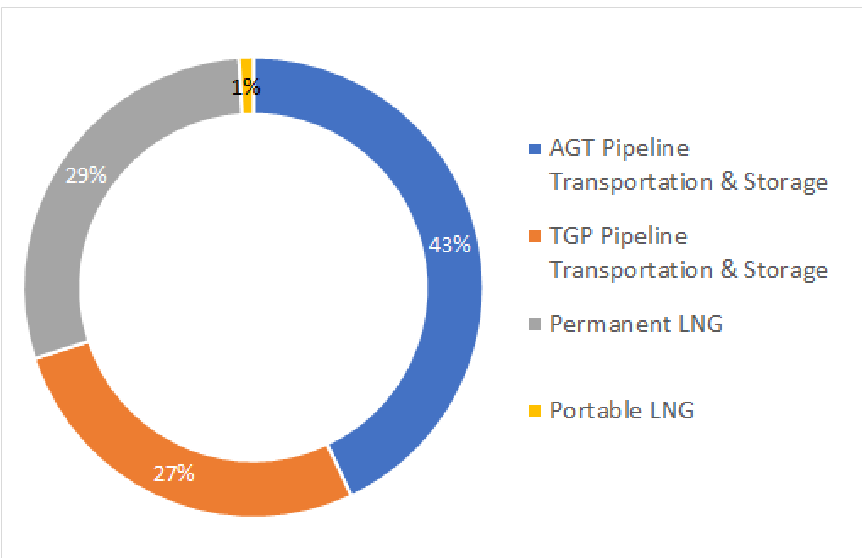
AGT is a Northeastern interstate natural gas pipeline that extends from New Jersey up into Massachusetts. The AGT G-system is a lateral that branches off of the AGT mainline in southern Massachusetts and extends south and east to serve parts of Rhode Island and

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

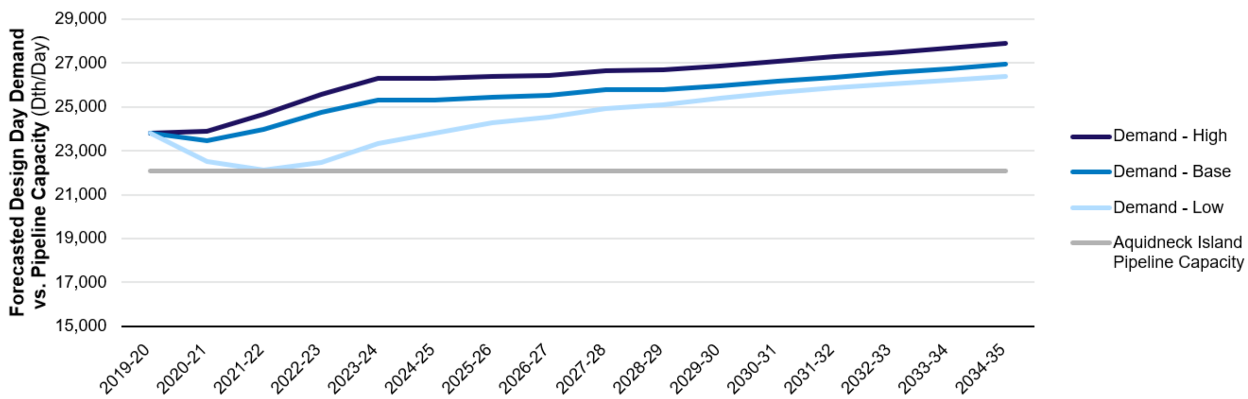
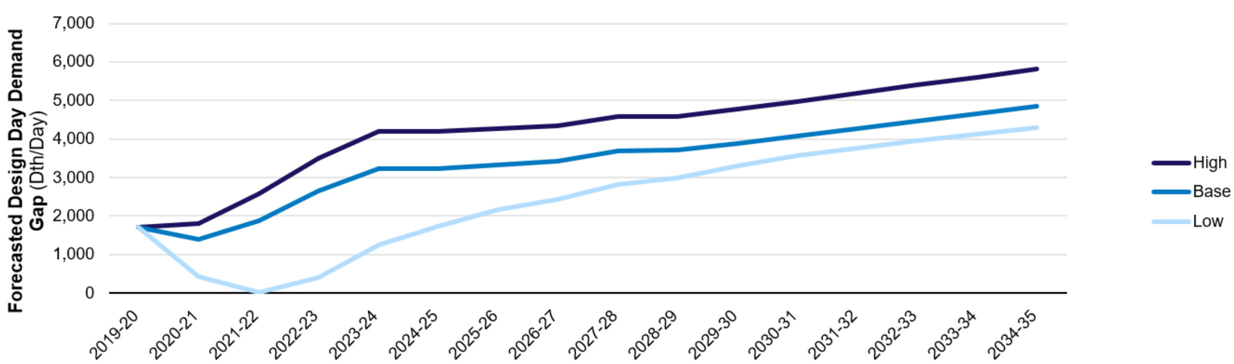


Figure 8: Forecasted Gap Between Design Day Demand and Available Pipeline Gas Capacity for Aquidneck Island



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

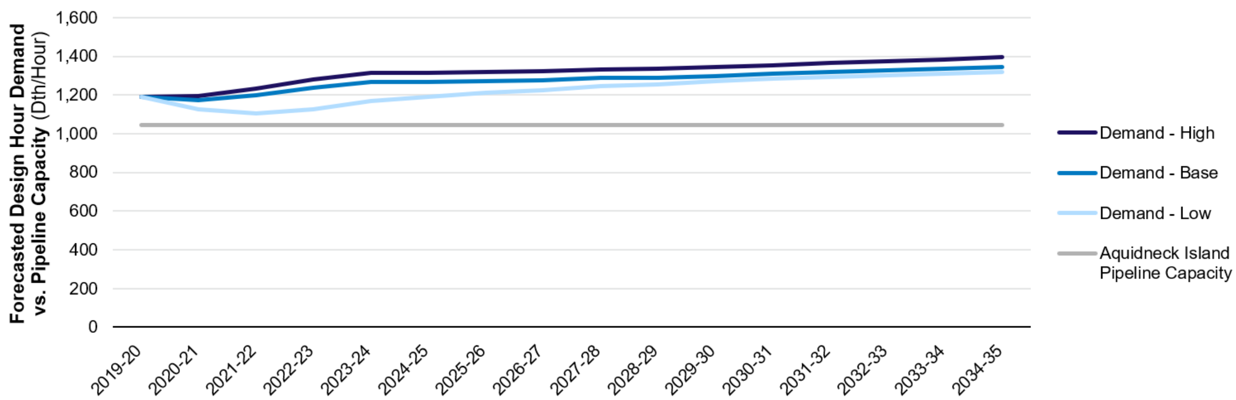
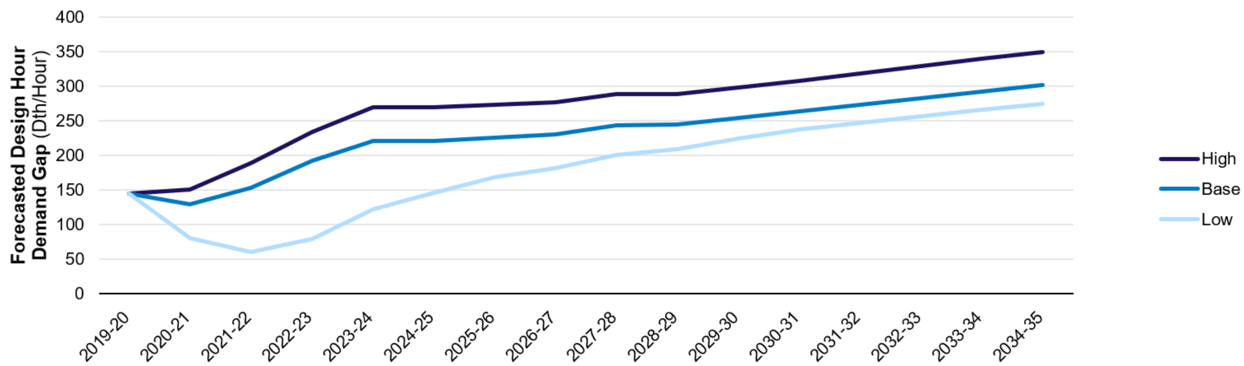


Figure 10: Forecasted Gap Between Design Hour Demand and Available Pipeline Gas Capacity for Aquidneck Island



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 CO_2. 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.

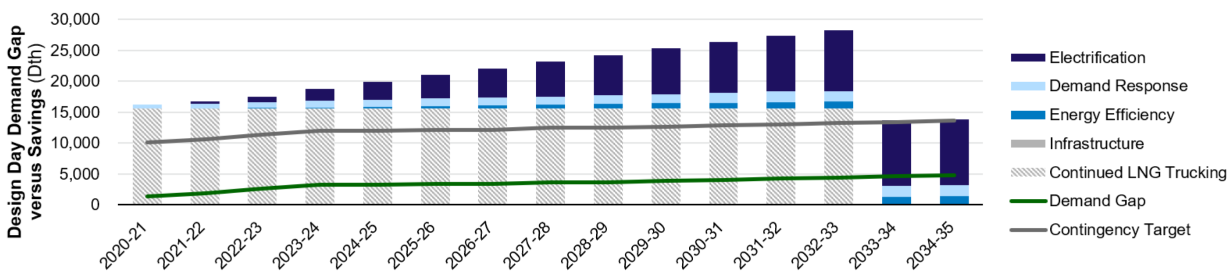
Only gas demand reductions on Aquidneck Island itself can help address the capacity constraint need. Without an AGT project implemented, gas demand reductions elsewhere in Rhode Island supplied from AGT cannot free up gas to deliver to Aquidneck Island owing to the inability to flow more gas to Aquidneck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

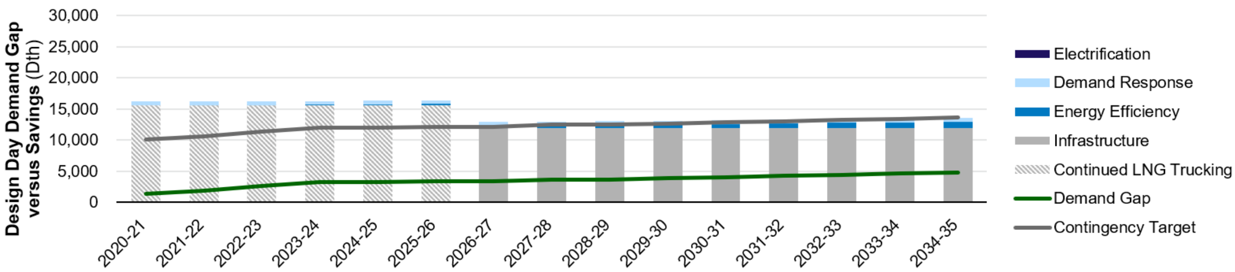
- A portable LNG solution on an indefinite basis – this option would create the infrastructure needed to support portable LNG at the new Navy site and rely on that portable LNG solution indefinitely in lieu of the portable LNG at Old Mill Lane
- A portable LNG solution on an interim basis to be replaced 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

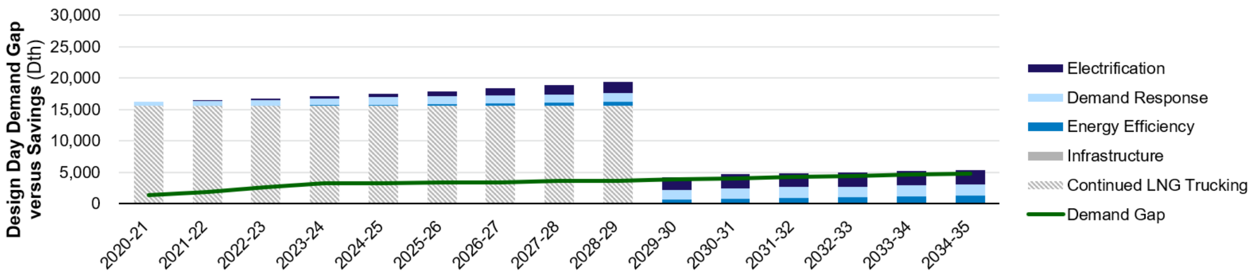
The details of an AGT project are yet to be determined and could range from a more narrowly targeted system reinforcement project to address needs on Aquidneck Island to a broader system expansion project that would address regional needs of multiple gas utilities. The scope of the project would determine 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 contigency Trucked LNG at the New Navy Site would provide upon completion in 2024-25, held constant with forecasted growing demand.

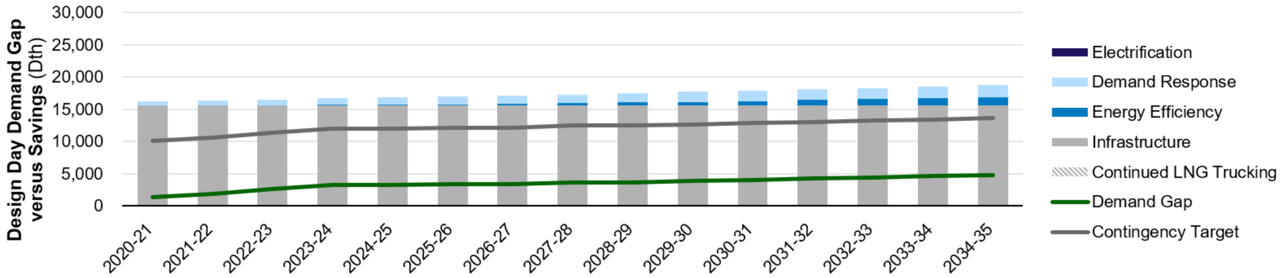
9.5. Continue to Use Old Mill Lane Portable LNG

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.

		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 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.	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.

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.

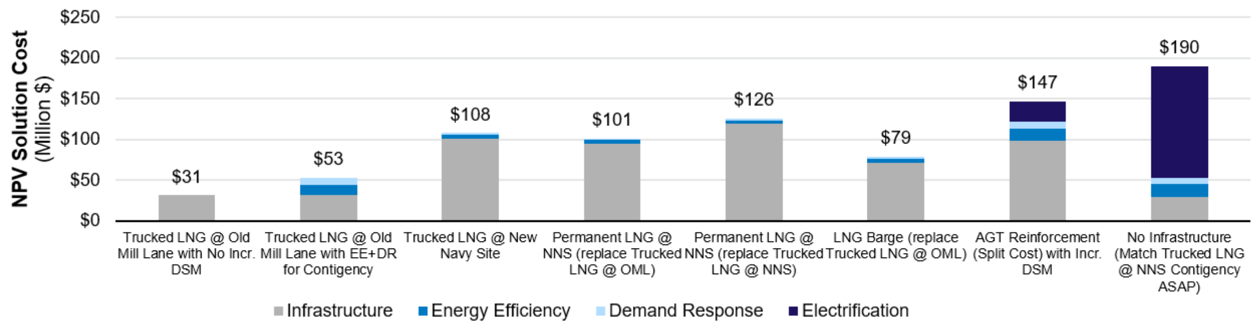
The Company also looked at the cost of the options under the high and low long-term gas demand scenarios but found no material change in the relative costs.

[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%

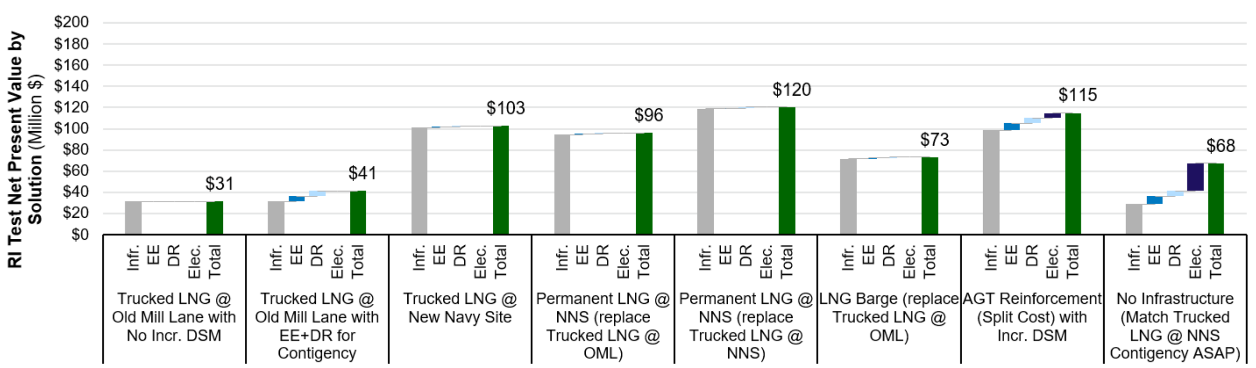
Non-Infrastructure	Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification	$63	3.7%

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

<u>High Efficiency Boilers & Furnaces: Replace on Burnout (ROB)</u>

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