Testimony of

David G. Hill, Ph.D.

Energy Futures Group

Before the Rhode Island Energy Facilities Siting Board

On Behalf of Conservation Law Foundation

October 12, 2023

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I. EXECUTIVE SUMMARY

David G. Hill is a Managing Consultant with Energy Futures Group ("EFG"), Inc. He is testifying in this proceeding on behalf of the Conservation Law Foundation ("CLF") regarding The Narragansett Electric Company's (d/b/a Rhode Island Energy) ("Narragansett" or the "Company") Portable Liquefied Natural Gas ("LNG") Vaporization Project at Old Mill Lane in Portsmouth, RI ("LNG Vaporization Project" or "Project"). He testifies to provide information to the Energy Facility Siting Board ("EFSB") regarding the Company's application for a license to operate the LNG Vaporization Project as a more permanent installation, rather than its current seasonal and transient deployment. His testimony presents the findings of his high level review of the Company's petition, the alternatives presented, and the supporting analyses provided therein. His review finds that a license for the Company to operate Vaporization Project may be unnecessary to support demand on Aquidneck Island beyond the near term. His testimony presents these findings and recommendations for an improved outcome. Based on his expertise and experience, he testifies that licensing the LNG Vaporization Project, while needed in the near term, is not justified as a preferred long-term solution to resolve the capacity constraint or capacity vulnerability as presented by the Company in the instant application. He also testifies that the permanent siting of the LNG Vaporization Project, as opposed to continued seasonal operation of the equipment, may make achieving Rhode Island's emission reduction requirements more challenging. Thus, after review of the Company's application and supporting materials he recommends that should the EFSB grant a license to Narragansett to operate the LNG Vaporization Project, such a license be granted on the following conditions: (1) the Project should continue to be operated on a seasonal basis in support of actual and reported capacity constraints and capacity vulnerabilities; (2) the Company should be required to invest and deploy non-infrastructure solutions identified by the Company's analysis in the Long-Term Capacity Report from 2020[1] and the analysis supporting the instant application, to address demand on Aquidneck Island; and (3) within one year of the EFSB's decision the Company should be required to produce a plan for implementation of the non-infrastructure programs referenced above, with annual reporting documentation that shall include information on usage of the LNG facility; (4) the license should require a review for continued need prior to the 2026/2027 heating season, and should sunset after the 2030/2031 heating season. His testimony includes comments on the Public Utility Commission's ("PUC") Advisory Opinion in this matter issued on June 5, 2023.

David assisted and provided senior advice for his colleague, Earnest White, in the preparation of his testimony on behalf of CLF submitted to the Public Utility Commission ("PUC") on March 13, 2023, to support their review and development of an Advisory Opinion to the EFSB in this matter. Dr. Hill appeared at the PUC hearing on May 8th adopting Mr. White's testimony. Mr. White left EFG as an employee in May of 2023.

[1] National Grid, *Aquidneck Island Long-Term Gas Capacity Study* (Sep. 2020) ("Long Term Capacity Report" or "LTCR"), attached as Exhibit CLF-1-3.

II. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is David G. Hill. I am a Managing Consultant at EFG, located at 10298 Route 116, Hinesburg, Vermont, 05461.

Q. Please describe Energy Futures Group.

A. Energy Futures Group is a clean energy consulting firm established in 2010. EFG specializes in the design, implementation, and evaluation of energy efficiency and renewable energy programs and policies. EFG has worked on behalf of utilities and other program administrators, government and regulatory agencies, and environmental, low-income, and affordable housing advocacy organizations in 40 states and Canadian provinces, as well as several countries in Europe. EFG's recent work includes analysis of Rhode Island's investments in gas infrastructure, expert testimony on a proposed gas supply contract before the New Hampshire Public Utilities Commission, expert testimony on three proposed gas company pilots in Illinois, modeling and development of pathways for Vermont to achieve its emission reduction requirements, and analysis and strategic planning support for the Connecticut Energy Efficiency Board, the Rhode Island Energy Efficiency and Resource Management Council and the Massachusetts Energy Efficiency Advisory Council and Department of Energy Resources.

Q. Please summarize your professional and educational experience.

A. I joined EFG in January of 2020. My recent and current work includes several assignments relating to gas infrastructure, pilot programs, and planning. In early 2020, I led an EFG team and was the lead author for a critical assessment of National Grid's long-term needs assessment of gas supplies and proposed pipeline infrastructure investments for their downstate New York service territories. I was also the lead author for an expert report, prepared for CLF, which assessed critical issues for gas system infrastructure investments in Rhode Island.[2] In 2021, I filed expert witness testimony with the Illinois Commerce Commission on three proposed gas pilot programs in Illinois on behalf of Citizen's Utility Board, Environmental Defense Fund and the Natural Resources Defense Council.[3] Other recent work related to long-term energy planning and the future of gas include serving as a co-leader of the technical consultant team for the Vermont Climate Council as they developed and adopted a Climate Action Plan to meet the requirements of Vermont's Global Warming Solutions Act, and leading a team conducting building sector analyses and integrated scenario planning for the Massachusetts Decarbonization Roadmap.

In the electric sector recent work includes submitting and defending expert testimony on grid improvement plans in Illinois on behalf of Environmental Defense Fund and Citizens Utility Board, and in North Carolina on behalf of a coalition led by the Southern Environmental Law Center. I have also submitted testimony on the characterization and analysis of energy efficiency and demand response in Dominion Energy South Carolina's 2020 Integrated Resource Plan on behalf of the Southern Environmental Law Center and the Coastal Conservation League. In 2019, I presented at a technical workshop on efficiency portfolio diversification and submitted supporting testimony in Nova Scotia on behalf of EfficiencyOne. In 2018, I provided testimony on behalf of the Ecology Action

[2] Attached as Exhibit CLF-1-2.
[3] Illinois Commerce Commission, Dockets No. 21-0098 and 20-0722.

Centre to the Nova Scotia Utility and Review Board regarding NS Power's Advanced Metering Infrastructure project. From 2010 to 2020, I provided ongoing expert review and testimony on EmPOWER Maryland's energy efficiency portfolio on behalf of that state's Office of People's Counsel.

Prior to joining EFG, I worked for the Vermont Energy Investment Corporation ("VEIC") for 22 years, starting in 1998 as an analyst, subsequently holding several positions over the decades, and serving my last five years as Director of Distributed Resources and Policy Fellow. As the Director of Distributed Resources and a Policy Fellow at VEIC, I was responsible for advancing sustainable energy program design and evaluation. I have provided testimony in regulatory hearings on more than two dozen occasions and have participated in scores of technical workshops and working groups on behalf of many clients. I earned my Ph.D. in Energy Management and Policy Planning at the University of Pennsylvania. Further details on my work experience and education are provided in my professional resume, included as Exhibit CLF-1-1.

Q: Have you previously made an appearance before the EFSB?

A: Yes, in 2022 I made an appearance before the EFSB in Docket SB-2021-03, supporting the Direct Testimony filed by my EFG colleague Gabrielle Stebbins.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of CLF.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information to the EFSB as it considers the Company's Application for a License to Construct and Alter Major Energy Facilities

("Application") filed on May 19, 2021. The Company asserts that it currently operates the LNG Vaporization Project on a seasonal basis to support gas supply in the region during times of system stress in winter on an ad hoc basis. The Company submits this Applications in order to make certain improvements to the site used to deploy the LNG Vaporization Project on a more permanent basis. The Company asserts the improvements submitted for approval in the instant Application would improve the physical site where the LNG vaporization plant is deployed and increase the capacity throughput at Old Mill Lane, which the Company asserts will lead to faster and safer deployment of the LNG Vaporization Project in winter and when needed at other times of the year. The Company also states further improvements would decrease noise pollution for surrounding communities.

The Company asks the EFSB for a license to operate the LNG Vaporization Project itself, rather than through a third party on an as-needed basis, as is currently done. In support of its Application the Company asserts the following: (1) the LNG Vaporization Project is necessary to meet the needs of the state and Aquidneck Island's natural gas distribution system; (2) the LNG Vaporization Project is cost-justified; (3) the mobilization and operation of the LNG Vaporization Project will not cause unacceptable harm to the natural or social environment and will enhance the socio-economic fabric of the state; and (4) the site of the LNG Vaporization Project is the only viable location available for the Company to meet this need.

Q. How does your testimony relate to the testimony filed by Earnest White with the PUC on March 13, 2023?

A. The testimony I am submitting draws from the testimony submitted to the PUC by Mr. White. I provided senior advisor support and review for Mr. White during the development of that testimony, and due to Mr. White having a family emergency, I adopted his testimony and participated in the PUC hearing on May 8, 2023 on his behalf. Much of the material I present in my testimony is identical to Mr. White's previous testimony. My testimony also includes comments on the PUC Advisory Opinion issued on June 5, 2023 in Docket No. 22-42-NG.

III. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your key findings and recommendations.

A. After review of the Company's Application, I recommend that should the EFSB grant a license to Narragansett to operate the LNG Vaporization Project, and that such a license be granted on the following conditions:

(1) the Project should continue to be operated on a seasonal basis in the near-term to support planned or unplanned transmission supply interruptions or peak capacity constraints;

(2) Within one year of the EFSB's decision, the Company should be required to file an implementation plan, with target dates and milestones, for solutions focused on energy efficiency, demand management and electrification to reduce peak demand on Aquidneck Island. The plan should be required to reflect coordination and collaboration with other programmatic initiatives and incentives, such as the Clean Heat Rhode Island program

offered by the Office of Energy Resources.[4] Doing so will take advantage of the technologies, incentives and support networks that other entities are developing to help Rhode Island meet its greenhouse gas reduction mandates, and these are complementary to the the Company's initiatives and investments. A plan based on a coordinated effort should reduce program costs for the Company, while promoting the levels of gas to electric heat pump conversions necessary to reduce and eventually eliminate the capacity constraint conditions justifying the continued operation of the vaporization project. This recommendation for coordination does not eliminate the need for the Company to develop their own incentives and initiatives, but recognizes that activities beyond those directly delivered by the Company will contribute to reductions in gas demand and help alleviate the near-term capacity constraint. When considering the costs and benefits of non-infrastructure alternatives to reduce demand, I recommend the Company be directed to use appropriately discount rates and apply the Rhode Island Test.

(3) the Company should be required to report annually on implementation of the initiatives referenced above, and their impact on demand. The annual reporting should include information on usage of the LNG facility; and

(4) the license should sunset and the end of the 2030/2031 heating season as the Company's own analysis suggest that it could with an deployment of demand-side management ("DSM") and electrification. I also recommend a review of the continued need for operation of the plant be conducted prior to the 2026/2027 heating season.

[4] *See* R.I. Office of Energy Res., *Clean Heat Rhode Island Incentives* (last visited Oct. 12, 2023), https://cleanheatri.com/resources/incentives/.

IV. NEED FOR THE LNG VAPORIZATION FACILITY

Q. Please summarize the Company's proposal and stated need for the LNG Vaporization Facility.

A. The Company asserts the need for the LNG Vaporization Project is driven by customer demand on its gas distribution system during what it calls "capacity vulnerabilities" and "capacity constraints." Capacity vulnerability is related to upstream interruptions in gas supply. A report produced by the U.S. Department of Transporation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") indicates that the 2019 capacity vulnerability event was a unique event caused by three simultaneous disruptions.[5] The PHMSA findings, as well as those of the Rhode Island Division of Public Utilities and Carriers ("DPUC")[6], indicate that the disruptions were not solely due to insufficient infrastructure, but were also related to and likely could have been avoided by operational decisions and processes that were in the Company's control. Furthermore, the Company acknowledged the proposed LNG facility, by itself, is not sufficient to eliminate capacity vulnerabilities.[7] These findings confirm that relying solely on infrastructure solutions, such as the proposed LNG facility, is not sufficient to address potential capacity

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[5] PHMSA, *Events Contributing to Natural Gas Outages on National Grid's Distribution System in Newport, Rhode Island* (August 2019), *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/regulatory-compliance/pipeline/accident-investigation-division/72801/rhode-island-natural-gas-outages-summary-report-web.pdf.

[6] DPUC, *Summary Investigation Into the Aquidneck Gas Service Interruption of January 21, 2019* 8-9 (2019).

[7] *See* Table 2-1 at page 10 of the Siting Report (indicating that in the event of a total supply disruption on a design day, 44% of customers on Aquidneck Island would experience service interruption even with the LNG Vaporization Project in place).

vulnerabilities. This underscores the importance and value of planning and deploying non-infrastructure solutions such as electrification, efficiency and demand management.

The capacity constraint is directly related to peak demands on Aquidneck Island. I provide analysis, conducted as part of Mr. White's testimony, illustrating that customers' demand on Aquidneck Island has not been more than the throughput to the island for some time. The Company's answers to discovery questions suggest the LNG Vaporization Project has been used for just four hours since the 2019 Event to support reliability on Aquidneck Island since 2019. The Company's analysis appears to suggest the LNG Vaporization Project would only be required through the 2030–2031 timeframe.

My recommendations to require the Company to plan for and implement initiatives to support higher levels of energy efficiency, demand management and electrification will shorten the timeframe in which the facility is needed to address capacity constraints. This course of action is consistent with the findings of the PUC's Advisory Opinion that while there may be an immediate and short-term need for the facility, non-infrastructure solutions can address capacity vulnerability in the longer-term. It is also consistent with the binding emissions reduction mandates of the Act on Climate.[8]

Q. Do you have any comments on capacity vulnerability and the 2019 Event?

A. Yes, my comments on this question draw directly from Mr. White's testimony before the PUC. Based on the findings of the DPUC and PHMSA investigations the 2019 event can be characterized as a low probability, high impact event – an event for which multiple

[8] *See* R.I. Gen. Laws § 42-6.2-2.

systemic and operational failures were required. PHMSA summarized the sequence of events leading to the outage on Aquidneck Island in its report on the incident.[9] Many, if not most, of the conclusions of the PHMSA report indicate that the Company had control of the factors leading to 2019 Event. As the PHMSA Report demonstrates, the 2019 Event required a cascade of operational errors and malfunctions. It is likely that had any one of these events not occurred the 2019 Event would not have occurred.[10] Many of the factors that would prevent a similar catastrophic incident in the future are within the Company's control. As suggested by the PHMSA report improvements in planning, operational control and communications would go a long way to addressing the asserted capacity vulnerability in a durable and long-term manner.

The results of the scenario modeling done by PHMSA illustrate how the required pressure of 100 pounds per square inch ("psig") was maintained across a series of scenarios isolating the major events, and is reproduced below as Table DGH-1.

[9] PHMSA Report at 24.
[10] "If any one of the three factors (overtakes, NG LNG ESD, Weymouth meter configuration error) had not occurred, there would have been adequate pressure to maintain customers on Aquidneck Island." PHMSA Report at 24.

	NG LNG	Weymouth Meter	NG Providence G System Takes	Others G System Takes	Pressure @ Portsmouth Inlet*	Significance
Base Case	Down	Error	Actual	Actual	38 psig	Actual conditions
Scenario 1 - What if NG LNG did not fail?	Operating	Error	Est. takes assuming NG LNG is operational.	Actual	109 psig	The impact of NG LNG had the third most impact to the pressures at Portsmouth.
Scenario 2	Down	Error	Contract Limit	Actual	151 psig	Scenario 2 and 3 are an inverse of each other. Impact from overtakes by NG (54% of the volume) is about the same as the overtakes by the rest of the customers on the G system.
Scenario 3	Down	Error	Actual	Contract Limit	151 psig	
Scenario 4 - What if Weymouth did not fail?	Down	No Error	Actual	Actual	158 psig	The impact of the Weymouth meter configuration error was the second most impactful to the pressure at Portsmouth.
Scenario 5 - What if there were no overtakes?	Down	Error	Contract Limit	Contract Limit	221 psig	The greatest impact is due to customer overtakes on the G-System.
Scenario 6	Operating	No Error	Est. takes assuming NG LNG is operational.	Actual	211 psig	Demonstrates the impact of the overtakes irrespective of the malfunction of NG LNG and Weymouth.

Table DGH-1. Results of PHMSA Scenario modeling of the 2019 Event[11]

Q. The Company also states that growth in demand necessitates the LNG Vaporization Project, do you have any comments on the demand for natural gas on Aquidneck Island?

A. Yes. According to the Company's response to discovery, the maximum contracted offtake at Algonquin is 1,045 DTH/hr.[12] Additionally, the Company provided the historic demand at the Portsmouth Gate. Figure DGH-1, below, provides the first quarter peak

[11] PHMSA Report at 22.
[12] TNEC Response to CLF Data Request 1-2 in PUC Docket No. 22-42-NG, attached as Exhibit CLF-1-4.

demand, which is the highest peak demand for the Company at this station, from 2015 through 2022. As can be seen the general trend in demand for natural gas at the Portsmouth Gate has been declining since the peak of nearly 1,400 DTH/hr in 2017.

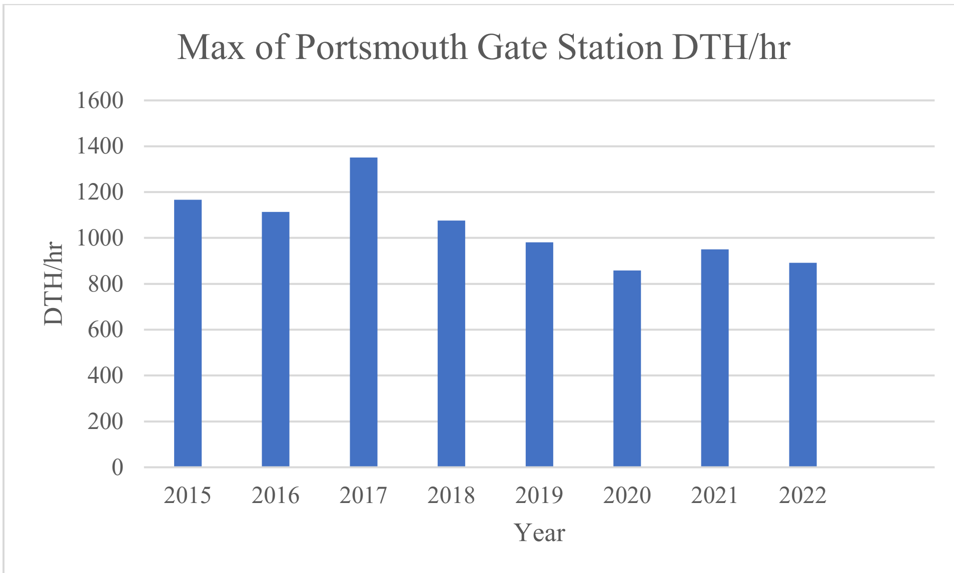

Figure DGH-1. Maximum Offtake at Portsmouth Gate Station 2015-2022

Since 2018, demand at the Portsmouth Gate has not exceed 1,000 DTH/hr – this includes the 2019 Event. This underscores that the operation of the LNG Vaporization Project may be very limited if only used during times of capacity constraints.[13] Additionally, when taken in the context of the DPUC Report and PHMSA Report, it calls into the question the capacity constraint as a singular threat to reliability on Aquidneck Island. Last, as the trend in peak demand appears to be decreasing generally, a focus on non-infrastructure

[13] The Company asserts the vaporization rate is driven by the need of approximately 181 Dth/hr for a projected supply shortfall based on its demand forecast starting in winter 2022/23. Siting Report at 12. The Company also states that some portion of the pipeline on Aquidneck Island is being uprated, from six-inch pipeline to twelve-inch pipeline. The Company asserts this will improve pressures in the pipeline between the Portsmouth M&R Facility on Old Mill Lane and its connection to the Algonquin Gas Transmission's system. *See* TNEC Response to Middletown Data Request 2-4 in PUC Docket No. 22-42-NG, attached as Exhibit CLF-1-5.

solutions could accelerate this trend, helping the state to accomplish its emissions reduction mandates, while decreasing the reliance on gas heating on the island over the long term.

Q. Do you have any comments on the Company's assessment indicating that a moratorium on new gas connections would result in additional greenhouse gas emissions?

A. Yes, the testimony of Ms. Porcaro cites the Company's assessment that given a moratorium on new gas connections customers "might opt for heating fuels that result in emissions that are greater than those produced by the burning of natural gas."[14] The Company's assessment is based on the faulty assumption that customers would adopt fuel oil or propane rather than cold climate heat pumps. Considering current market conditions, and the incentives and market support provided by Clean Heat Rhode Island program, and Federal funding through the Inflation Reduction Act, the Company's assessment that a moratorium on new gas connections would result in an increase in greenhouse gas emissions is not valid.

V. ALTERNATIVES TO PERMANENT SITING OF THE VAPORIZATION PROJECT

Q. Please describe the alternatives the Company considered to the permanent siting of the LNG Vaporization Project.

A. In the Siting Report, the Company provided an analysis of the following peak shaving alternatives to the proposed LNG Vaporization Project: (1) Seasonal Portable LNG

[14] Testimony of Julie M. Porcaro at 14.

operation at a New Navy Site; (2) Permanent LNG at a New Navy Site; (3) LNG Barge; (4) Algonquin Reinforcement Project; (5) Non-Infrastructure Solution; (6) Non-Infrastructure solutions to address capacity constraint only; (6) the Company also considered several other alternatives that were ruled out.[15]

Q. Do you have any comments on the Company's analysis of potential alternatives to the permanent siting of the LNG Vaporization Project?

A. Yes, I have several concerns with the way the non-infrastructure options were evaluated and presented. The direct testimony of Company witness Ms. Porcaro indicates that the alternatives considered were all "*more expensive than the Project, did not provide the operational advantages of being located next to the take station where the distribution system can accept and effectively distribute the vaporized LNG being injected into it, or would take several years to implement during which the proposed project would be needed*."[16]

Beyond this cursory dismissal, Ms. Porcaro's testimony does not provide estimates of the costs for alternative solutions. For more details on alternative solution costs one needs to refer to the Siting Report and the LTCR. Figure DGH-2 presents a summary comparison of the non-infrastructure cost estimates and their wide variation. The first 6 columns on the left side of the Figure illustrate estimates from sections 4.7 and 4.8[17] of the April 2022 Siting Report. The two bars on the right side of the graphic illustrate cost estimates

[15] Siting Report at Section 4.
[16] Testimony of Julie M. Porcaro at 12, lines 11-15.
[17] Section 4.7 of the Siting Report assesses Non-infrastructure solutions to Address Capacity Constraints and Provide Contingency for Capacity Vulnerability. Section 4.8 assess non-infrastructure solutions that address capacity constraints only.

from the LTCR report. The figure illustrates how the Company's inconsistent approach (on use of discounted costs) and tests (utility cost test or Rhode Island Test), creates a broad and confusing range of estimates for non-infrastructure alternatives.

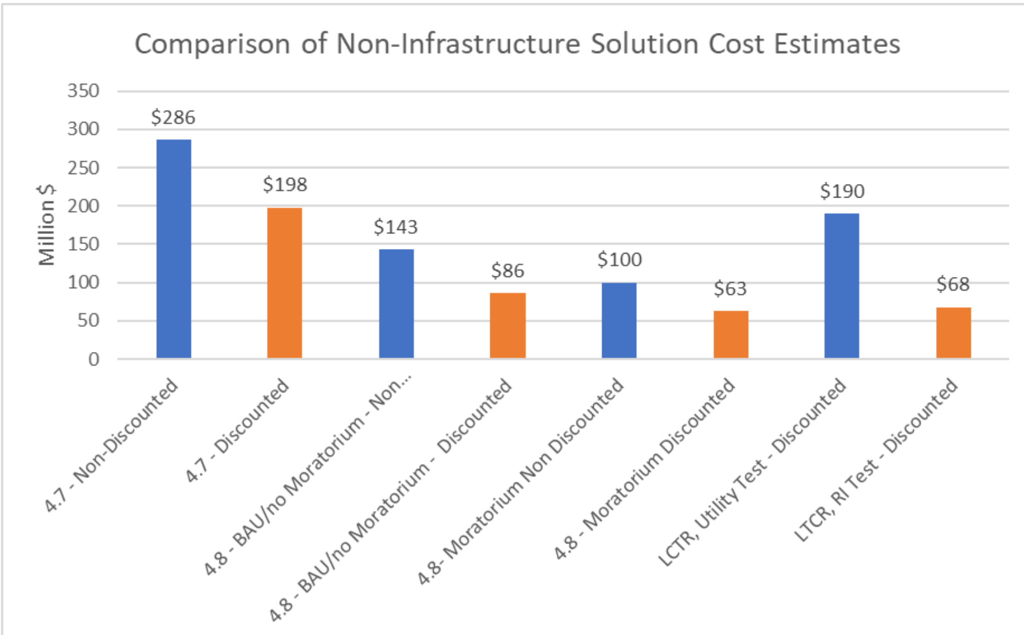

Figure DGH-2. Comparison of Company's Non-Infrastructure Cost Estimates

In their narrative presentation and comparison of non-infrastructure alternatives the Company consistently focuses on the higher estimates, which are based on non-discounted costs, and the utility cost test.[18] These higher estimates are represented by the blue columns in Figure DGH-2.

Both cause concern. When comparing alternatives with future year savings and costs, it is fundamental and appropriate to use discounted costs and benefits. In the Siting Report,

[18] *See, e.g.*, Section 4.7.1, p. 34 of the Siting Report, and Table 4-1 on p. 38, both highlight the highest cost estimate of $286 Million.

the Company relegates the discounted cost results to footnotes.[19] The Company's presentation and primary use of non-discounted results muddies the water, and it is not a helpful or valid basis for comparison.

Second, to properly understand and evaluate the comparative value of long-lived energy investment alternatives the Rhode Island Benefit Cost Test ("RI Test") should be used instead of the utility cost test. As the names imply, the RI Test provides a more comprehensive comparison of the societal costs and benefits of alternatives by including both customer and utility costs and savings. The Company is required to use the RI Test for Efficiency Program Plan Filings[20], and the RI Test is used and discussed in the 2020 LTCR study. However, the more recent 2022 Siting Report (columns labeled 4.7 and 4.8 in Figure DGH-2 above) only examines alternative costs based on the utility cost test.

Q. What is the impact of using discounted values and the RI Test to compare the costs of non-infrastructure alternatives?

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[19] *See* Siting Report, footnotes 19, 20, and 21.
[20] *See, e.g.*, 2019 Rhode Island Test Description, http://rieermc.ri.gov/wp-contednt/uploads/2018/08/2019-eepp-attachment-4-ri-test-first-draft-external.pdf; 2020 Rhode Island Test Description, http://rieermc.ri.gov/wp-content/uploads/2019/09/2020-eepp-attachment-4-ri-test-third-draft.pdf

A. Using discounted costs and benefits and the RI Test results in consistently and significantly lower costs for the non-infrastructure alternatives. This is illustrated in Figure DGH-2 by the orange columns representing the Company's own estimates of non-infrastructure costs, which are significantly lower when discounting and the appropriate cost test are applied.

Q. When discounted costs and the RI test are applied does the non-infrastructure alternative become the least-cost solution?

A. No, but as the cost for the non-infrastructure solutions become closer to those for the permanent development of the Vaporization Facility at the Old Mill Lane site, it becomes more important to further examine how the alternatives can limit the time horizon over which the facility will be necessary and to make decisions to maximize the flexibility and optionality of future use of vaporization at the site.

Q. What other concerns does the Company raise over the non-infrastructure alternatives?

A. As mentioned above, the current filing's discussion of alternatives is very limited. Looking back, in the LTCR report the Company identifies a number of potential issues and barriers to non-infrastructure solutions, but these are mostly general in nature, and not backed up by analysis. For example, the Company identifies a concern that ramping up efficiency, demand response and electrification on Aquidneck Island could undermine efforts elsewhere in the state and undermine the ability to meet gas demand reduction goals.[21] This assumes that the level of demand response and efficiency across the state is a zero-sum game and that increasing activity in one region must be balanced by a decline in activity elsewhere. This is a faulty premise, pre-supposing that the need, ability and opportunity to grow electrification, demand response and efficiency statewide are not feasible.

Other potential barriers discussed in the LTCR include the potential transfer payments to customers on Aquidneck Island from elsewhere in Rhode Island, the potential need for electric distribution system upgrades, workforce development, and customer economics for electrification and weatherization. These are legitimate planning considerations, but the Clean Heat Rhode Island Program, the Inflation Reduction Act ("IRA") and the Infrastructure Investment and Jobs Act ("IIJA") create significant potential to overcome these issues through Federal tax credits and direct incentives supporting efficiency, electrification, infrastructure development, and workforce development. Increased implementation of the efficiency, demand response, and electrification elements of the non-infrastructure alternative are consistent with the State's policy goals related to reduction of greenhouse gas emissions.[22]

Q. Does the Company acknowledge the potential for LNG at Old Mill Lane as a temporary solution along with increased non-infrastructure investments to meet needs in a flexible manner?

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[21] Siting Report at 35.
[22] In Rhode Island's 2022 Climate Plan Update, the state's Executive Climate Change Coordinating Council ("EC4") ("EC4 Report") listed increased energy efficiency, increased use of electric heat pumps, and pursuit of other non-pipe alternatives which "seek alternative ways of providing thermal service to Rhode Islanders, rather than expanding and enforcing the fossil gas network" as priority actions for the thermal sector. EC4, Rhode Island 2022 Climate Update (2022), attached as Exhibit CLF-1-6.

A. Yes. Quoting from the LTCR study, the Company states: "*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*." [23]

Moreover, the Company also states that the capacity constraint can be mitigated by a variety of non-infrastructure solutions in its Siting Report.[24]

VI. COMMENTS ON THE ADVISORY OPINION FROM THE PUC

Q. Have you reviewed the PUC Advisory Opinion issued on June 5, 2023 in Docket No. 22-42-NG.

A. Yes.

Q. Do you have comments or recommendations to the EFSB based on your review of the Advisory Opinion?

A. Yes. My first set of comments addresses the need for the project. I agree with the Advisory Opinion finding that there is a current and short-term need for the vaporization plant to meet capacity constraints. I also agree with the Advisory Opinion finding that the capacity constraint may be addressed by non-infrastructure solutions in the longer term. As the Advisory Opinion states: "RI Energy has not shown that there is a permanent need for LNG varporization on Aquidneck Island.[25]" The Advisory Opinion also finds that the

[23] LTCR at 5.
[24] Siting Report at 34-38.
[25] Docket No. 22-42-NG, In RE: The Issuance of Advisory Opinion to the Energy Facilities Siting Board Regarding the Narragansett Electric Company d/b/a Rhode Island Energy Application to Construct an LNG Vaporization Facility on Old Mill Lane, Portsmouth, Rhode Island, at 5.

Company's "assertion that LNG vaporization is needed on the island for as long as the gas system is in operation is not supported by the record".[26]

Q. Do you agree with the Advisory Opinion's recommendation to issue a license with a mandate for periodic reviews to ensure continued need?

A. Yes, I agree with the PUC Advisory Opinion's recommendation of periodic review to determine continued need. I recommend that the periodic review require the Company to demonstrate that it has made reasonable efforts to identify and implement, through their own initiatives or in collaboration with others, activities that reduce or eliminate the capacity constraint. Even while the facility is still in use and necessary, demand side measures lower overall demand and therefore the number of customers that could be left without heat in the event of a total upstream supply disruption. I would recommend and support a directive that the design of the periodic review explicitly acknowledge, as an objective, the elimination of the need for continued operation of the LNG vaporization facility to meet the Island's capacity needs.

Q. **Do you have comments on the Advisory Opinion's position with respect to leasing versus ownership of the LNG facility?**

A. I do. The Advisory Opinion indicates the finding there is a short-term need for the project should not be substituted as a finding tht the ownership model or the sizing of the unit and its proposed costs are appropriate for rate-making or cost recovery decisions. I agree with Advisory Opinion on this position. The facility has operated on a temporary

[26] *Id.* at 5, note 17.

seasonal basis under leasing agreements for many years. At a time when the finding regarding need is that the short-term capacity constraint should not be considered as permanent, shifting to a long-term capital investment to be placed in rate base is inappropriate. It would place an undue risk on ratepayers that over time the plant is no longer needed to meet capacity constraints and yet the costs must still be recovered. Even if there is a higher short-term cost associated with the operational expense of leasing the facility, there is a value to the flexibility provided by not locking in a commitment to the infrastructure.

Q. Do you have comments on the Advisory Opinion findings related to the cost justification?

A. Yes. The Advisory Opinion finds "the proposal to operate LNG facilities at Old Mill Lane represents the least cost solution to meet the need compared to the alternatives examined by the Company."[27] I agree with this finding, noting however, that when the Company used the Rhode Island Test, and discounted results in the 2020 Long-Term Gas Capacity Study, the costs for non-infrastructure alternatives are significantly lower than those from the 2022 Siting Report.

Furthermore, I recommend any license granted by the EFSB be conditioned on a requirement the Company conduct further analysis on the ability of any Company initiative to complement and build upon efforts such as the Clean Heat Rhode Island Program which is providing incentives and other programmatic support for strategic electrification and clean heat adoption. The activities of the Clean Heat Rhode Island

[27] Advisory Opinion at 8.

Program are designed to help the state meet its greenhouse gas emission reduction requirements, and are consistent with the recommendations from the Rhode Island Executive Climate Change Coordinating Council (RIEC4), and the Heating Sector Transformation in Rhode Island Report prepared by the Brattle Group for the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Office of Energy Resources. My recommendation is that it is entirely reasonable to direct the Company, to identify and evaluate non-infrastructure alternatives, including increased gas efficiency, demand management, limitations and or moratorium on new connections, and strategic electrification that when combined with the complementary efforts of the Clean Heat Rhode Island Program, eliminate the ongoing need for the vaporization facility.

Q. Do you have any comments regarding the Advisory Opinion's recommended timing of the periodic review of continued need?

A. Yes, the Advisory Opinion indicates conducting the first review in 2028, after the Company files its next Long Range Gas Supply Plan.[28] Given the critical Act on Climate Milestones in 2030, I would respectfully recommend against allowing five years to lapse, by waiting until 2028 for the periodic review. Instead, I recommend the first periodic review be conducted prior to the 2026/2027 heating season, and that it be based on a directive for the Company to identify and evaluate the Company directed and collaborative non-infrastructure alternatives that will eliminate the ongoing need for the LNG vaporization facility.

[28] Advisory Opinion at 8.

VII. CONCLUSION

Q. Can you please summarize your recommendations?

A. Yes, I recommend that should the EFSB grant a license to Narragansett to operate the LNG Vaporization Project, and that such a license be granted on the following conditions:

(1) the Project should continue to be operated on a seasonal basis in the near-term to support planned or unplanned transmission supply interruptions or peak capacity constraints;

(2) within one year of the EFSB's decision, the Company should be required to file an implementation plan, with target dates and milestones, for solutions focused on energy efficiency, demand management and electrification to reduce peak demand on Aquidneck Island. The plan should be required to reflect coordination and collaboration with other programmatic initiatives and incentives, such as the Clean Heat Rhode Island Program;

(3) the Company should be required to report annually on implementation of the initiatives referenced above, and their impact on demand. The annual reporting should include information on usage of the LNG facility; and

(4) a review of the continued need for the plant and the operating license should be conducted prior to the 2026/2027 heating season and the license should sunset after the 2030/2031 heating season.

Q. Does this conclude your testimony?

A. Yes.

David Hill
Managing Consultant

CLF-1-1

ENERGY FUTURES GROUP

Professional Summary

David Hill joined EFG as a Managing Consultant at the start of 2020, after 22 years of employment with VEIC, most recently as Director of Distributed Resources and a VEIC Policy Fellow. He is known nationally for his advancement of sustainable energy program design and evaluation, and renewable energy policy. David has been the principal investigator and led analysis teams for multi-year stakeholder informed studies on solar market and decarbonization pathways and scenarios. David provides expert testimony and regulatory support; participates in international, national, and state boards; leads policy committees and conferences; provides comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming; and supports program budget planning and implementation. He has led or significantly contributed to the design and development of efficiency and renewable energy programs with annual budgets of $100+ million for initiatives in New Jersey, Washington DC, New York, Vermont, Arizona, and Maryland. Recent work includes expert testimony and whitepaper analyses related to gas infrastructure investments, pilot programs and planning. He has clients in more than a dozen states and six countries; several of them are international organizations.

Experience

January 2020 – present: Managing Consultant, Energy Futures Group, Hinesburg, Vermont (VT)

2014 – 2019: Director, Distributed Energy Resources, Policy Fellow, VEIC, Burlington, VT

2010 – 2014: Managing Consultant, VEIC, Burlington, VT

2008 – 2010: Deputy Director, Planning and Evaluation, VEIC, Burlington, VT

2000 – 2008: Senior Consultant, VEIC, Burlington, VT

1998 – 2000: Consultant, VEIC, Burlington, VT

1993 – 1998: Research Associate, Tellus Institute and the Boston Center of the Stockholm Environment Institute

Testimony as Expert Witness

Expert witness and reports for technical working groups and before commissions on renewable energy, energy efficiency, and gas infrastructure, in Illinois, Vermont, New York, Rhode Island, New Jersey, Maryland, Pennsylvania, North Carolina, South Carolina, for the Federal Energy Regulatory Commission, Nova Scotia and Ontario.

Energy Futures Group, Inc

PO Box 587, Hinesburg, VT 05461 – USA | 802-482-4874 | dhill@energyfuturesgroup.com

2023 In the Matter of Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolia and Performance-Based Regulation, Docket No. E-2 Sub 1300, on behalf of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Sothern Alliance for Clean Energy and Vote Solar. March 27, 2023.

2022 In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rate Schedules and Charges Docket No. 2022-254-E, on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Vote Solar, South Carolina Public Service Commission, December 1, 2022.

2022 In the Matter of the Merger of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc. in Docket No. GM22040270, on behalf of Environmental Defense Fund, State of New Jersey Board of Public Utilities, November 10, 2022.

2022 *GTN Xpress Project: A Critical Review of Need, Cost and Impacts*, prepared for the Washington State Office of the Attorney General, and filed with the Federal Energy Regulatory Commission in Docket No.CP22-2-00, on behalf of the States of Washington, California, and Oregon.

2022 In the Matter of Avoided Costs for EfficiencyOne's 2023-2025 Demand Side Management Plan Application, before the Nova Scotia Utility and Review Board, on behalf of EfficiencyOne. February 11, 2022.

2022 Appearance before the Rhode Island Energy Facilities Siting Review Board, Docket SB-2021-03, regarding a declaratory Order filed by Sea 3 Providence. LLC. Hearing appearance in support of Direct Testimony of Gabrielle Stebbins of Energy Futures Group, on behalf of the Conservation Law Foundation.

2021 Nicor Smart Neighborhood and Total Green Pilots. Expert witness testimony on behalf of Citizens Utility Board, Environmental Defense Fund and Natural Resources Defense Council, Docket 21-0098 before the Illinois Commerce Commission.

2021 Nicor Renewable Natural Gas Pilot. Expert witness testimony on behalf of Citizens Utility Board and Natural Resources Defense Council, Docket 20-0722 before the Illinois Commerce Commission.

2020 *NH Saves 2021-2023 Triennial Plan.* Expert witness testimony reviewing joint gas and electric triennial efficiency plan before the New Hampshire Public Service Commission submitted on behalf of Clean Energy New Hampshire, DE 20-092.

2020 *Dominion Energy South Carolina, 2020 Integrated Resource Plan*. Expert witness testimony before the South Carolina Public Service Commission submitted on behalf of Southern Alliance for Clean Energy and the South Carolina Coastal Conservation League on the characterization and analysis of energy efficiency and demand response in Dominion's 2020 IRP. Docket No. 2019-226-E.

2019 *Efficiency One 2020-2022 DSM Plan: Portfolio Diversification and Lighting Transition*. Expert Witness Testimony submitted on behalf of Efficiency Nova Scotia, to the Nova Scotia Utility and Review Board, Matter 09096.

2018 *In the Matter of an Application by Nova Scotia Power for Approval of its Advanced Meter Infrastructure Project*. Expert Witness Testimony submitted on behalf of Ecology Action Center, to the Nova Scotia Utility and Review Board, Matter 08349.

2018 *Becoming an Advanced Solar Economy.* Testimony before the Vermont House Committee on Energy and Technology, Montpelier.

2017 Maryland Public Service Commission. On behalf of Office of People's Counsel on EmPOWER Maryland Utilities 2018-2020 plans. Presentation and testimony, October 25-26, 2017.

2016 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual (Q3 and Q4) Review.* Presentation and testimony, May 4, 2016.

2015 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual Review.* Presentation and testimony, October 14-15, 2015.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015-2017 Utility Proposed Plans.* Presentation and testimony, October 21-22, 2014.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. Evaluation of Semi-Annual Reports - Case Nos. 9153-9157. Presentation and testimony, April 7, 2014.

2013 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petitions of the Pennsylvania Power Company for Approval of its Act 129 Phase II Energy Efficiency and Conservation Plan (Docket Nos. M-2012-2334395 and M-2012-2334392); Petition of Metropolitan Edison Company (Docket No, M-2012-2334387); and Petition of West Penn Power Company (Docket No. M-2012-2334398). Written testimony. January 8, 2013.

2013 Maryland Office of People's Counsel, EmPOWER Maryland. *Written comments on 2012 Q3-Q4 Semi-Annual Report.* Presentation and testimony, October 2-3, 2013.

2011 Maryland Office of People's Counsel. *Utility-Specific Comments on the 2012-2014 EmPOWER Maryland Program Plans*. Case Nos. 9153-9157. Written testimony. October 19, 2011.

2011 Maryland Office of People's Counsel. *Written Comments on 2010 Annual Reports, and Q4 2010 reports*. Case Nos. 9153-9157. Presentation and testimony. March 31, 2011.

2011 Maryland Public Service Commission. On behalf of the Maryland Office of People's Counsel. *Comments on the 2012-2014 EmPOWER Maryland Utility Program Plans.* October 2011.

2009 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petition of Duquesne Light Company for Approval of Its Energy Efficiency and Conservation and Demand Response Plan, Docket No. M-2009-2093217. August 7, 2009.

2005 Ontario Energy Board. On behalf of Green Energy Coalition, regarding Hydro One Networks and Brampton Conservation and Demand Management Plans. February 4, 2005 (written comments) and February 17-18, 2005 (testimony).

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future, regarding net metering standards. Written comments and testimony. June 2005.

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future. Written testimony and comments on interconnection standards. April 2005.

2005 Testimony to the Vermont State Legislature House Committee on Energy and Natural Resources on Vermont's Solar and Small Wind Incentive Program. February 9, 2005.

Selected Projects (from more than 100)

Vermont Agency of Natural Resources. Co-leader of Vermont Pathways Analysis team providing technical support and quantitative modeling to the Vermont Climate Council, leading to adoption of Vermont Climate Action Plan.

Conservation Law Foundation. Lead author, for "*Rhode Island's Investments in Gas Infrastructure A Review of Critical Issues*", discussing renewable gas potential, gas planning in relation to greenhouse gas reduction goals and, depreciation periods for gas new infrastructure.

Institute for Energy Economics and Financial Analysis. Lead author, for "*Critical Elements in Short Supply: Assessing the Shortcomings of National Grid's Long-Term Capacity Report*", study calling into question proposed natural gas pipeline investment for New York City region.

Massachusetts Executive Office of Energy and Environmental Affairs. Senior advisor for team creating Low Emissions Analysis Platform (LEAP) integrated scenario modeling to inform Massachusetts efforts to reach greenhouse gas reduction targets.

Pennsylvania Department of Environmental Protection. Led team creating scenario modeling using the Low Emissions Analysis Platform (LEAP) model in support of two- and half-year study "*Pennsylvania's Solar Future*". Presentations for modeling review and collaborative stakeholder feedback at more than half a dozen stakeholder meetings and webinars.

U.S. Department of Energy. Principal Investigator for a three-year SunShot Initiative Solar Market Pathways study, investigating the technical, regulatory, and business model implications of getting 20 percent of Vermont's total electric supply from solar by 2025.

Sun Shares. Created and launched, and responsible for management and business development of, a community solar business subsidiary to provide "Easy and Affordable Solar for Employers and their Employees," 2015 – present.

New Jersey Clean Energy Program. Program design and policy advisor for the renewable energy program for more than a decade.

Rhode Island Office of Energy Resources. Strategic Advisor on State Energy Plan and System Reliability Procurement and Distributed Generation programs.

Alaska Energy Authority. Principal consultant for two studies on renewable and energy efficiency financing and funding strategies.

New York State Energy Research and Development Authority (NYSERDA). Twice led the renewable energy analysis for 20-year forecast of energy efficiency and renewable energy potential, 2003 and 2012.

World Bank. Expert consultant on a short-term study of efficiency and micro- / mini-grid opportunities in Tanzania, 2014.

Arizona Public Service. Managed a rapid assessment and redesign of PV and solar hot water incentives, 2009.

Selected Presentations

2017 Sun Shares, Easy and Affordable Solar for Employers and their Employees, American Solar Energy Society, Solar 2017, Denver.

2017 Vermont Solar Market Pathways, American Solar Energy Society, Solar 2017, Denver.

2016 *Oxymoron: Harmonizing Distributed Energy Integration Realities with Policy Frameworks*. Solar Power International.

2015 World Bank, International Conference on Energy Efficiency in Cities, Puebla New Mexico. Invited Panel speaker on Efficiency Vermont and Third-Party Administration Model. February, 2015.

2015 *Vermont Solar Market Pathways.* Presentations at Solar 2015 (State College, Pennsylvania), and Renewable Energy Vermont Conference.

2014 New York State Energy Research and Development Authority (NYSERDA), Renewable Energy Potential Study Results, Albany, NY.

2013 *Transformative Energy Planning*. Invited speaker at Innovations in Renewable Energy Symposium, Metcalf Institute for Marine and Environmental Reporting, Narragansett, Rhode Island.

2012 World Renewable Energy Forum, 2012 – Welcome Address and Introduction of Keynote Plenary Speakers. American Solar Energy Society, Denver.

2012 *Efficiency Vermont: A Successful Statewide Clean Energy Utility Model.* Presented at the 2012 Business of Clean Energy in Alaska Conference, Anchorage.

2011 Nova Scotia Feed In Tariff Forum: Invited speaker for two panels addressing Regional Coordination and Export Potential and International Feed-in Tariffs.

2011 *Integrating Renewable Energy and Efficiency Services.* Presentation to the Clean Energy States Alliance Fall 2011 Meeting, Washington, DC.

2010 *The Potential for Energy Efficiency and Renewables as Resources in Wholesale Capacity Markets,* Presentation at EUEC 2010 Conference, Phoenix, AZ.

2008 "Technology and Policy; Getting it Right." Solar Power International, Invited panel speaker. San Diego, California.

2008 *Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth*. Solar 2008, American Solar Energy Society.

2008 *Review of Efficiency Vermont Administrative Structure and Experience*. Penn Future 2008 Clean Energy Conference, May 2008.

2006 *Scoping Analysis of Potential Photovoltaic Contributions Towards Offsetting Transmission System Upgrades in Southern Vermont.* Solar 2006, American Solar Energy Society.

2006 *Growing New Construction Markets for Photovoltaics: Recent Strategies and Activities from LIPA's Solar Pioneer Program.* Solar 2006, American Solar Energy Society, 2006.

2005 *Market Response to Photovoltaic Incentive Offerings: An Analysis of Trends and Indicators*. Presented at the International Solar Energy Society Solar World Congress, 2005.

2003 *Solar Energy Value and Opportunities in Vermont*, Invited Session Panel Moderator and Speaker, 2nd Annual Power for a New Economy Conference, Burlington, Vermont, October 8, 2003. Renewable Energy Vermont.

2003 *Renewable Energy Case Studies: Redefining the Models, Refining the Messages, and Getting the Word Out*, Invited Session Panel Moderator, Solar 2003 National Solar Energy Conference, Austin, Texas June 22, 2003. American Solar Energy Society.

2002 *Transforming Markets for Customer Sited Clean Renewable Energy: Connecting Field Experience with Lessons from the Efficiency World*, Invited Session Panel Moderator, Solar 2002 National Solar Energy Conference, Reno, Nevada June 18, 2002. American Solar Energy Society.

1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change.* Software and paper prepared for the United Nations Industrial Development Organization, presented at the 1997 ACEEE Summer Study on Energy Efficiency in Industry.

1997 *E2/FINANCE: A Software System for Evaluating Industrial Eco-Efficiency Opportunities*, sponsored by the U.S. Department of Energy. ACEEE 1997 Summer Study on Energy Efficiency in Industry.

1995 *Process Evaluation of Three Gas Utility Commercial Industrial Demand Side Programs.* Prepared for the Colonial Gas Company, and presented at ACEEE 1995 Summer Study on Energy Efficiency in Industry.

Selected Publications

2017 Smart Electric Power Alliance, 51st State Initiative, *Role of Utilities in the Transforming Energy Economy of the 51st State*, September 2017.

2016 *Vermont Solar Market Pathways: From a Developed to an Advanced Solar Economy*. A Phase II Roadmap document prepared for the *Smart Electric Power Alliance 51st State Initiative*.

2016 *Vermont Solar Market Pathways,* Vols. 1-4. U.S. Department of Energy, Sun Shot Initiative, Office of Energy Efficiency and Renewable Energy. Award DE-EE-0006911. www.Vermontsolarpathways.org.

2016 *Energy Efficiency Program Evaluation and Financing Needs Assessment*. Report prepared for the Alaska Energy Authority, May 2016.

2015 *Michigan Renewable Resource Assesment*. Final Report, prepared for the Michigan Public Service Commission Staff under agreement with the Clean Energy States Alliance. April 2015.

2012 *Renewable Energy Grant Recommendation Program: Process and Impact Evaluations.* Principal in Charge for comprehensive two-volume study. Alaska Energy Authority.

2011 "Solar in Nepal: Small Systems, Big Benefits." *Solar Today.* July / August 2011.

2011 "National Clean Energy Standard: Congress Needs to Design It Properly." Perspective with Shaun McGrath and Jeff Lyng. *Solar Today.* July / August 2011.

2010 "National RPS Now!" *Solar Today*. July / August 2010.

2009 "Carbon Regulation: What's the Most Effective Path?" *Solar Today*. June 2009.

2009 "Policy Recommendations for the 111th Congress: Tackling Climate Change and Creating a Green Economy." Prepared by the American Solar Energy Society Policy Committee.

2008 "Pennsylvania Solar Assessment." Final Report, November 25, 2008. Incorporated into American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency, Demand Response, and Onsite Solar Energy in Pennsylvania.* ACEEE Report No. E093. Washington, DC: ACEEE, April 2009.

2008 "Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth." *Proceedings of Solar 2008*, American Solar Energy Society.

2004 "Cost Effective Contributions to New York's Greenhouse Gas Reduction Targets from Energy Efficiency and Renewable Energy Resources." *Proceedings of 2004 ACEEE Summer Study on Energy Efficiency in Buildings.*

2002 "The Ten Percent Challenge: A Participatory Community Scale Climate Campaign." *Proceedings of 2002 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, (with Tom Buckley, Jennifer Green, and Debra Sachs).

2000 "Implementing and Monitoring Community-Based Climate Action Plans." *Proceedings of 2000 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, pp. 149-160 (with Tom Buckley, Mark Eldridge, Debra Sachs, and Abby Young).

1998 *Eco-Efficiency Financing Resource Directory*. Electronic web-site, and printed directory prepared for the Environmental Protection Agency, Region I, New England.

Regulatory and Other Governmental / NGO Documents

2000 – 2012 *New Jersey's Clean Energy Programs – Honeywell Team Program Plans.* Led team on designing and implementing of Renewable Energy Program plans and initiatives. Many program plans and strategies for transition to market-based incentives.

1998 – 2008 *Long Island Power Authority's Clean Energy Initiative.* Lead Technical and Senior Advisor on Renewable Energy Plans, including the Solar Pioneer Initiative and Residential Energy Efficiency Programs.

2000 *The Climate Action Plan: A Plan to Save Energy and Reduce Greenhouse Gas Emissions*, Lead author for the Burlington (Vermont) Climate Protection Task Force.

1998 *Home Weatherization Assistance Program Environmental Impact Analysis*. Prepared for the Ohio Department of Development, Office of Energy Efficiency.

1997 *Achieving Public Policy Objectives Under Retail Competition: The Role of Customer Aggregation*. Prepared for the Colorado Governor's Office of Energy Conservation.

1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change*, software and paper. For the United Nations Industrial Development Organization.

1997 *Review of the Swaziland Energy Information System and Report on LEAP Training Activities*. Prepared for the Ministry of Natural Resources and Energy, Government Kingdom of Swaziland.

1996 *Evaluation of the IDB's Policies and Practices in Support of Renewable Energy and Energy Efficiency: A Report to the Inter-American Development Bank*. Brower and Company and Tellus Institute.

1996 *Action Plan for the Massachusetts' Industrial Services Program (ISP)*, prepared for the Sustainable Industries Initiative of the Corporation for Business Work and Learning.

1995 *Framework for National Energy Planning: Mission Report*, The Republic of Maldives. United Nations Department for Development Support and Management Services.

1994	*The SEI / UNEP Fuel Chain Project: Methods, Issues, and Case Studies in Developing Countries. Venezuela Case Study*.
1994	*Future Energy Requirements for Africa's Agriculture (Sudan Case Study)*. Report to the African Development Bank by the UN Food and Agriculture Organization.
1994	Report to the Idaho Public Utility Commission on Suggested Cost Allowances for the Idaho Power Company's DSM Programs. Prepared for the Idaho Public Utilities Commission, Tellus Report No. 94-177.
1994	Review of Pennsylvania Electric Company's 1995 Demand Side Management Filing. Prepared for: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-071.
1994	Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings. Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300.
1994	*Incorporating Environmental Externalities in Energy Decisions: A Guide for Energy Planners*. A Report to the Swedish International Development Agency. SEI-B Report No. 91-157.

Leadership

2017 – 2019	Energy Coop of Vermont, Board Member and Treasurer.
2013	Solar 2013, "Power Forward, Baltimore Maryland." Chair of Conference Advisory Committee responsible for recruiting and coordinating four main conference plenary sessions.
2012 – 2013	American Solar Energy Society (ASES), Chair of the Board.
2012	Policy Track Chair for the World Renewable Energy Forum, Denver, Colorado, May.
2009 – 2012	ASES Policy Committee, Board Member and Chair.
2007	Vermont Governor's Climate Change Committee, Member of the Plenary Working Group.
2000 – 2010	Renewable Energy Vermont, Founding Board Member, Past Board Chair.

Education

Ph.D., Energy Management and Policy Planning, University of Pennsylvania, Philadelphia, Pennsylvania (PA), 1993.

- Fulbright Scholar: Research on energy decision-making in rural Nepal, 1991 – 1993.

Master's, Appropriate Technology and International Development, University of Pennsylvania, Philadelphia, PA, 1989.

B.A., Geography and Political Science, Middlebury College, Middlebury, VT, 1986.

Other Qualifications

Nepal, Himalayan Light Foundation. Installed solar lighting systems in 3 remote health clinics and 3 homes, 2010.

Advanced PV Installation certificate. Solar Energy International, 2010.

Peace Corps volunteer. Sierra Leone, 1984 – 1986.

Languages

- Nepali: ILR Level 3, speaking; ILR Level 2, reading
- Krio and Mende (Sierra Leone): ILR Level 2, speaking

Software competency

- LEAP (Low Emissions Analysis Platform), Stockholm Environment Institute. Former trainer and current Principal Investigator of team using scenario modeling on three projects.
- NREL System Advisor Model. Financial and technical modeling tool for renewable energy systems.

Rhode Island's Investments in Gas Infrastructure

A Review of Critical Issues

Conducted by:

David G. Hill, Ph.D., Energy Futures Group

Chris Neme, Energy Futures Group

Prepared for:

Conservation Law Foundation Rhode Island

February 26, 2021

This whitepaper was prepared by David Hill of Energy Futures Group with review and support from Chris Neme of EFG, and James Crowley of CLF Rhode Island. Any omissions or errors are the responsibility of the primary author. Questions for the author should be directed to dhill@energyfuturesgroup.com

Table of Contents

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EXECUTIVE SUMMARY

Rhode Island's planning and investments in future energy infrastructure and resources need to consider how each decision contributes to, or possibly hinders, meeting of the state's greenhouse gas emissions reduction targets. Capital investments with long-lasting impacts deserve scrutiny to make sure they serve the public's best interests and that they are compatible with policy and legislated goals.

To meet their regulatory obligation to serve customers, gas utilities invest in capital assets, such as pipelines, meters, and compression stations, and recover the just and reasonable costs of those investments from gas consumers over time. The utility will typically recover such costs from gas consumers over a time horizon, established by the utilities commission, that is intended to be the time-period over which the asset will be used and useful. If an asset becomes obsolete and no longer provides useful service, before the costs of that asset have been fully recovered, those remaining costs are said to be a "stranded cost". Stranded costs may be borne by gas customers, if they are asked to continue paying for an asset even though it is no longer being used, or they may be borne by utility shareholders if the recovery of the stranded costs is not permitted by the utility commission. Stranded costs reflect an inefficient use of utility and consumer resources and are sought to be avoided by ensuring that the period of cost recovery for an asset is aligned as closely as possible with the lifetime over which an asset will be used and useful. Stranded costs are of particular concern at a time when states are developing and implementing plans to transition away from fossil fuels to mitigate climate damage, as the stranded costs risk slowing the transition and burdening consumers with additional costs.

This whitepaper discusses the importance of the depreciation period and other key issues related to the planning and regulatory review of investments in Rhode Island's gas infrastructure. Factors we review at a high level in the whitepaper include:

- Current and historic gas use by sector.
- Gas infrastructure safety and reliability plans.

- Rhode Island's statewide and corporate greenhouse gas goals.
- Pathways for decarbonized energy economy.
- The resource base and costs for renewable gas (RG) production.
- Other issues with reliance on RG.
- Analysis and comparison of alternatives to gas infrastructure investments, including strategic retirement and "pruning" of system assets, and
- The highest value future uses for gas and RG.

Based on our review of these policy, market, and resource conditions, and particularly in a state and region in which climate change policy and regulation are fast evolving, we urge utility commissions to bring especial rigor to their review of gas infrastructure depreciation schedules and to estimations of the useful life of such assets. We further recommend that, the likelihood of more rigorous climate regulation utility commissions should apply shorter depreciation periods for gas infrastructure investments, and in no case longer than 20 years. A shorter depreciation period reduces the risk of stranded costs to gas consumers and shareholders, better ensures a lower-cost transition to clean heating and it provides a better basis for comparing gas infrastructure investments with other alternatives.

Figure ES-1 illustrates the impact of a 20 versus a 33-year depreciation period, using a declining balance method and based on an investment of $180 million and a 10% salvage value. At the end of twenty years the shorter depreciation schedule (blue bars) will have recovered all costs. To do so, it has higher annual cost recovery for each of the first ten years in comparison to the 33-year deprecation period (orange bars). At the end of 20 years, the case with the longer (33 years) depreciation period has $26.7 million of unrecovered costs equivalent to 15% of the initial investment.

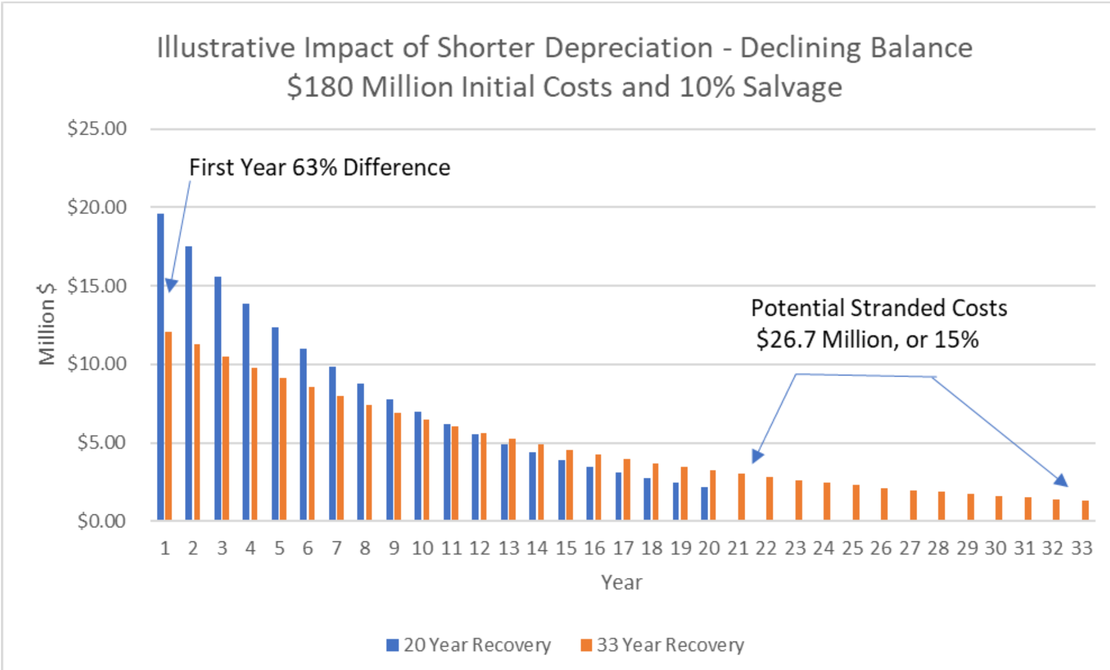


Figure ES-1: Comparison of 20 and 33-Year Depreciation Period

The longer depreciation period spreads costs over a longer time, but it also inherently carries more risk of stranded costs if the asset is retired or becomes obsolete. In this whitepaper we discuss how meeting Rhode Island's greenhouse gas targets, the cost and resource potentials for RG, and the benefit of targeting any future RG use to highest value applications all point towards reduced reliance on gas infrastructure. We therefore recommend a 20-year depreciation period be used to help reduce the risk of stranded costs, and to more accurately reflect the near-term rate impacts of investments that are undertaken.

The future of gas and electric infrastructure planning and investment is complicated. Its scale and associated economic and environmental impacts are significant, and it deserves thoughtful and inclusive planning processes and analyses. We support emerging and ongoing efforts along these lines. The shorter depreciation period we recommend in this whitepaper is just one of the steps that will help improve decision making and planning on gas infrastructure investments to better align them with climate change policy and objectives in Rhode Island.

Introduction

Utilities regularly make capital investments in assets required to provide services for their customers. They recover the costs for such investments from their customers over time. A depreciation period defines the length of time over which the utility recovers capital investment costs from consumers. There are many details, and variations making the accounting and rate design for cost recovery a complex, interesting, and sometimes contentious field for regulators, utilities, consumer advocates, and other stakeholders.

At the risk of simplifying some of this complexity, depreciation periods are fundamentally based on how long an asset is expected to be used and useful. A longer depreciation period spreads the cost recovery over more years. In comparison to a shorter depreciation period, the longer horizon will result in lower initial amounts of cost recovery (since costs are being recovered over a longer time). This can be favorable if the asset remains used and useful for the anticipated depreciation period, and future ratepayers receive services from the asset for which they are paying. However, there are risks if a depreciation period extends cost recovery too far into the future. If the asset becomes technically obsolete, unusable, or uneconomic before the end of the depreciation period, there are likely to be stranded costs to be borne either by ratepayers or by utility shareholders.

This whitepaper examines critical issues related to investment and planning decisions for gas infrastructure in Rhode Island. The first section gives a brief overview of how important gas has been in meeting Rhode Island's energy needs. Looking forward the future of gas and gas infrastructure in Rhode Island needs to be considered in relationship to many factors. These include greenhouse gas reduction targets, potential pathways for decarbonization, the potential costs and resource base for renewable gas, and the alternatives to investments in gas infrastructure. We provide a high-level analysis and discussion of the implications for each with respect to determining an appropriate depreciation period for gas infrastructure investments. Finally, we present our recommendation that shorter depreciation period (at most 20 years) is prudent and give an illustrative comparison to depreciation over 33 years.

Gas Consumption in Rhode Island

Gas is an important energy resource for Rhode Island. Figure 1 illustrates historic consumption in trillion British Thermal Units (Tbtu) per year. In 2018, the last year in this data series Energy Information Administration (EIA) data indicate gas accounted for more than 53% of Rhode Island's total energy consumption across all sectors of 195 TBtu. EIA estimates Rhode Island's 2019 gas consumption to be 97.6 TBtu, a decline of almost 7% from 2018.

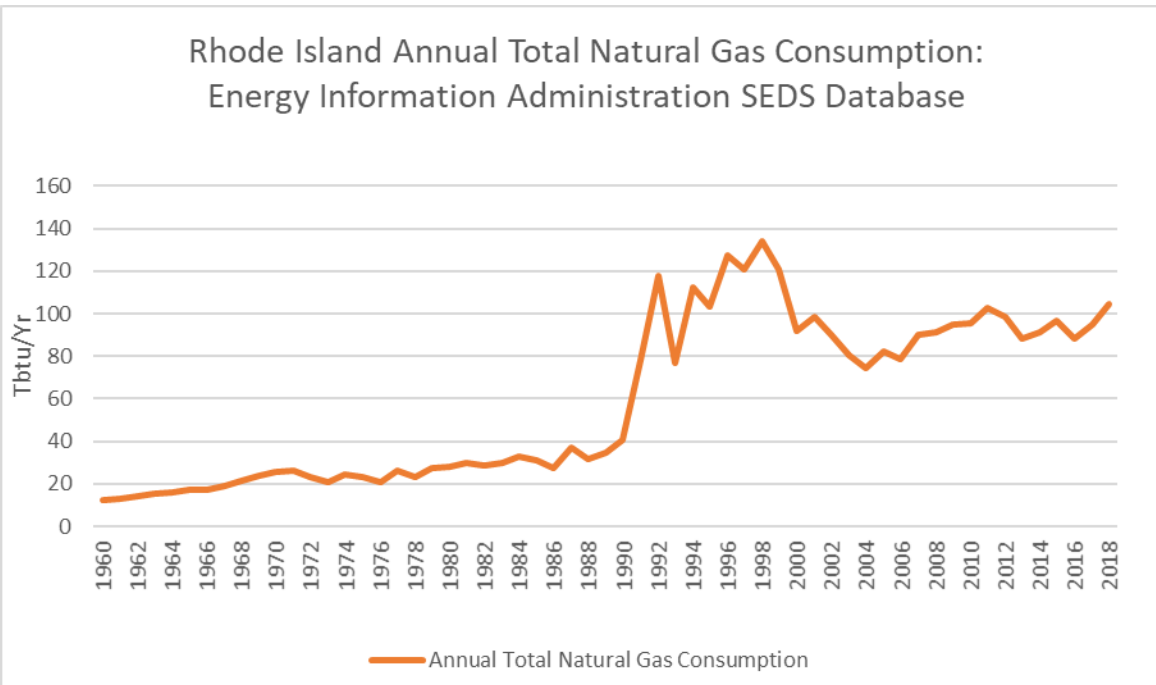


Figure 1: Historic Gas Consumption

The electric power sector is the largest consumer of gas in Rhode Island, accounting for more than half of the gas consumption in the state.[1] More than half of all Rhode Island households use gas as their primary heating fuel and residential heating accounts for roughly 20% of the total gas consumption. Commercial heating is the third largest consumer of gas accounting for about 13% of the total. Together, electricity generation, residential heating, and commercial heating account for 90% of total gas use. Figure 2 presents EIA data illustrating the shares of gas delivered

[1] https://www.eia.gov/state/analysis.php?sid=RI

to the electric power industry (green), residential consumers (blue), commercial consumers (orange), and total deliveries (yellow).

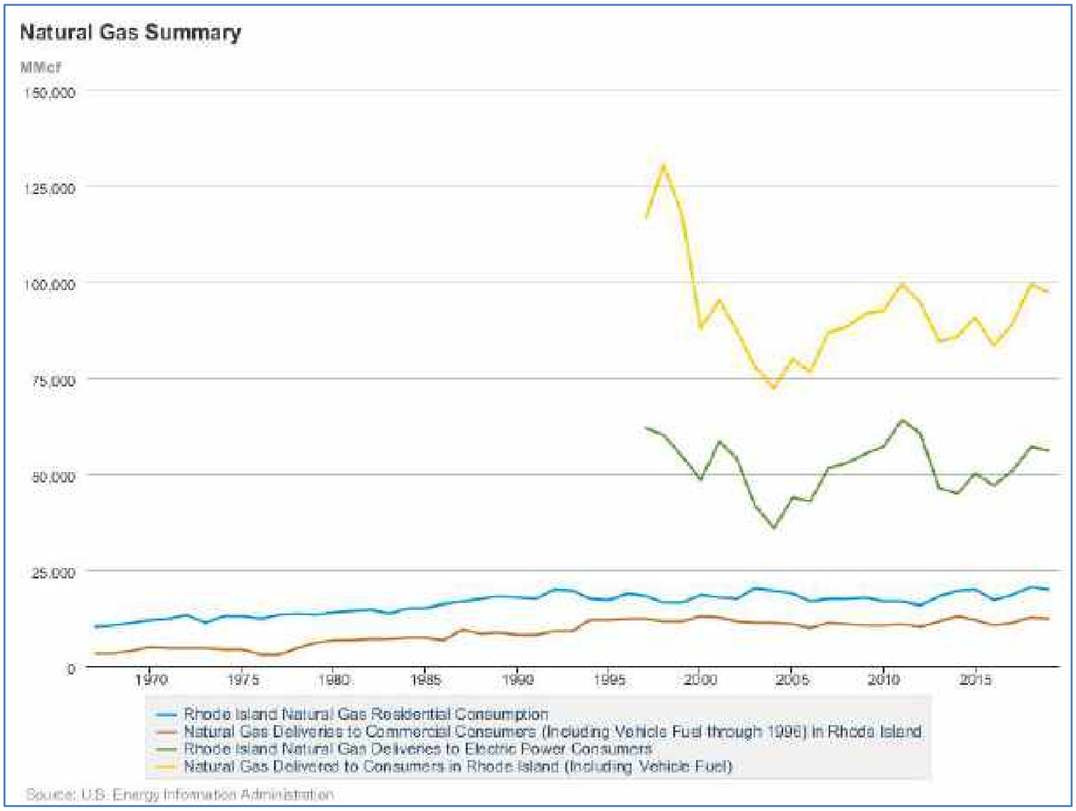


Figure 2: Rhode Island Gas Consumption by Sector

Gas Infrastructure Safety and Reliability Plans

In December 2021 National Grid submitted its proposed FY 2022 Gas Infrastructure, Safety and Reliability Plan (ISR Plan) to the Rhode Island Public Utilities Commission, in Docket No. 5099. The ISR Plan is designed to protect and improve the gas delivery system. It proposes a total of $180.15 million in discretionary and non-discretionary investments in the proactive replacement of leak-prone pipe, upgrading of system components, and addressing emergency leak situations and coordination of infrastructure investment with other construction projects.

Maintaining and improving the safety and reliability of the gas infrastructure system is unquestionably important. The National Association of Regulatory Utility Commissioners (NARUC), and the U.S. Department of Energy have issued recent whitepapers reviewing current activity, plans and cost-recovery issues related to maintenance and upgrading of gas infrastructure.[2] [3] Planning and potential investments in gas infrastructure need to consider the scale and span of future gas system needs, and the appropriate length of time for recovery of costs from ratepayers.

As detailed further below, meeting Rhode Island's greenhouse gas reduction targets will require drastic shifts in the volumes and uses of gas. The review and approval of proposed ISR plan investments should proceed based on careful consideration of the future gas system, and how this may be very different from the legacy infrastructure. Addressing factors such as the depreciation period for new gas infrastructure investments and considering strategic alternatives to infrastructure upgrades including the strategic retirement and pruning of system elements from the gas system will help reduce the risks of potentially redundant investments and stranded costs.

[2] National Association of Regulatory Utility Commissioners, Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs, January 2020.

[3] U.S. Department of Energy, Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations, Office of Energy Policy and Systems Analysis, January 2017.

Rhode Island's Greenhouse Gas Reduction Goals

The Resilient Rhode Island Act of 2014 established the Executive Climate Change Coordinating Council (EC4). It also set specific greenhouse gas emissions reduction targets; established an advisory board and a science and technical advisory board to assist the Council; and incorporated consideration of climate change impacts into the powers and duties of all state agencies. The targets for reductions the EC4 is charged with developing and tracking the implementation of a plan to achieve are represented in Figure 3.

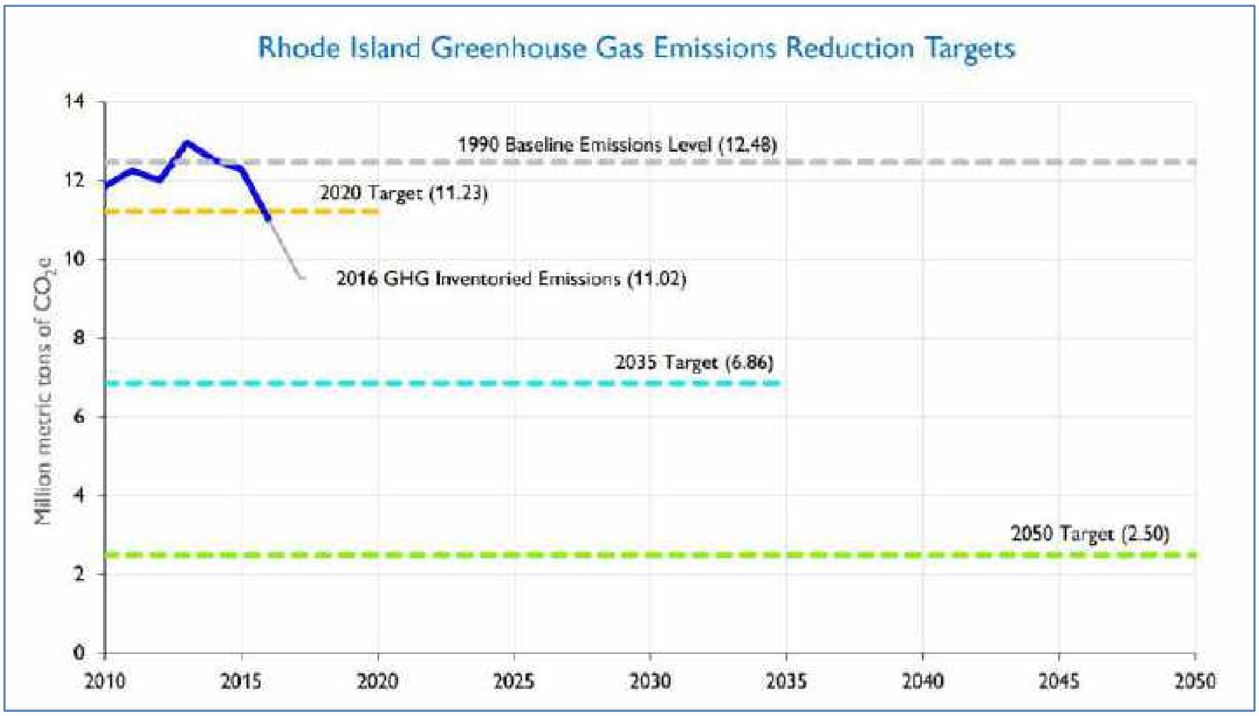


Figure 3: Resilient Rhode Island Greenhouse Gas Emissions Reduction Targets[4]

The 2016 Greenhouse Gas Emissions inventory indicates emissions from the three largest gas consuming sectors to be:

- Electric Generation - 2.84 MMTCO2e
- Residential Heating - 1.84 MMTCO2e
- Commercial Heating - 0.86 MMTCO2e

[4] http://www.dem.ri.gov/programs/air/documents/righginvent16d-pres.pdf

While these sectoral emissions are not exclusively from gas it is the predominant fuel source for each one. The combined 2016 emissions from these three sectors 5.54 MMTCO2e is more than 50% of the Rhode Island's total greenhouse gas emissions of 11.2 MMTCO2e. They are also more than 80% of the 2035 target (which is only 14 years away), and they are more than two times higher than the 2050 target (which is 29 years away). The 2016 inventory does not account for gas leakage, which one study estimates if properly accounted could raise total state emissions by 45%.[5] This brief overview makes it clear that strategies for reducing emissions from gas are essential elements for meeting Rhode Island's current GHG emissions reduction targets.

Furthermore, the best available science indicates we need to achieve zero net emissions by 2050 to avoid worst impacts of climate crisis from exceeding warming of 1.5 degrees Celsius.[6] With that in mind, legislation to increase the emissions reduction target to net zero by 2050 has been introduced in Rhode Island.[7] At the corporate level, National Grid, which owns and operates most of the gas and electric distribution infrastructure in Rhode Island also has its own zero by 2050 goal.[8]

Decarbonization Pathways

Meeting the already established Resilient Rhode Island greenhouse gas reduction targets for 2035 (only 14 years away) or for 2050 (29 years from now) will require significant shifts in the use of gas compared to the historic and current figures presented in Figures 1 and 2 above. Significant increases in electricity produced by renewable electric generation including solar, on- and offshore wind, imported hydropower, and other resources will result in a substantially decreased role and production from gas-fired electric generation, likely limiting their role to, at most, helping to balance intermittent renewable generation.

[5] Stockholm Environment Institute and Brown University Climate & Development Lab, *Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study*, September 2019.
[6] https://www.ipcc.ch/sr15/
[7] Rhode Island General Assembly, 2021 Act On Climate
[8] National Grid Net Zero by 2050 Plan

Emissions reductions in the space and water heating realm will likely be most cost-effectively achieved through electrification, using air and ground source heat pumps. Important analysis and planning undertaken in Rhode Island includes the "Heating Sector Transformation in Rhode Island" (HST) study.[9] Figure 4, from the Executive Summary of the HST illustrates estimates of annual space heating costs for a single-family residence, comparing projected costs in 2050 for fossil fuels with the 2050 decarbonized alternatives that will be required to meet GHG emissions reduction targets.

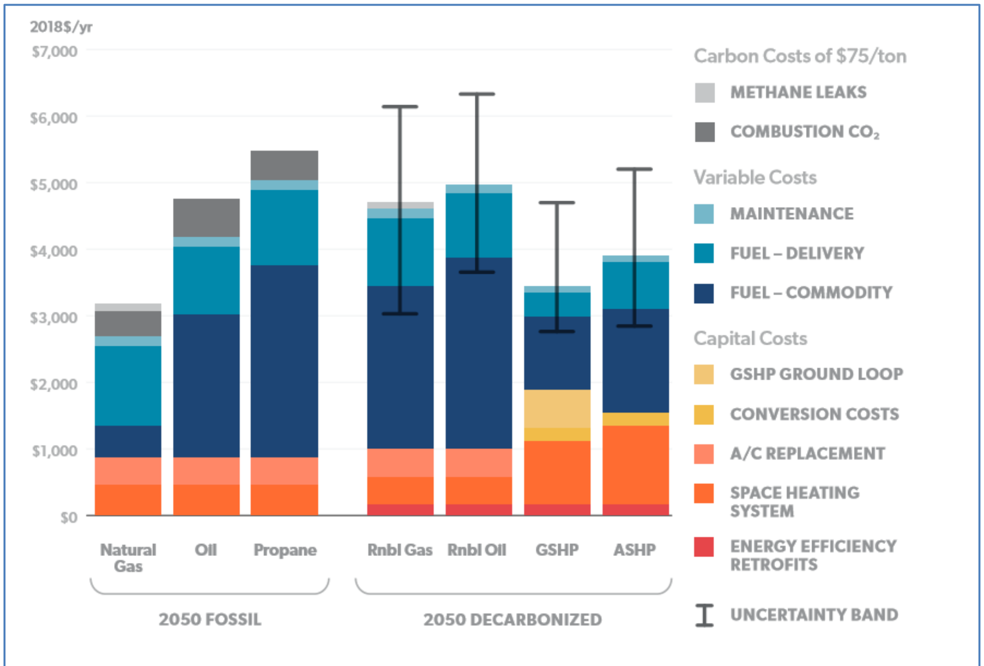


FIGURE ES 1: ANNUALIZED COST OF SPACE HEATING IN 2050, REPRESENTATIVE SINGLE-FAMILY HOME, BOOKEND SCENARIOS, 2018$

Figure 4: Economics of Residential Space Heating Decarbonization Options[10]

While there is some potential overlap in the estimated cost ranges, when considering the uncertainty bands, we observe the central cost estimates for the electrification options (GSHP and ASHP) are significantly lower than the renewable gas and oil options. The electrification options also have somewhat narrower uncertainty bands. The HST analysis and findings are consistent

[9] The Brattle Group, Heating Sector Transformation in Rhode Island, Prepared for the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Office of Energy Resources. Available here.
[10] The Brattle Group, HST Study, Executive Summary, page 2.

with other studies. In this light, planning and investment anticipating that renewable gas will be the sole, or even the dominant, pathway for decarbonization of space heating is not prudent.

Future heating shares by fuel type in 2050 as estimated by the HST study are further illustrated in Figure 5. Note that only the "Fuel Bookend" scenario results in an expansion of the share for renewable gas in comparison to the current share (54%) of fossil gas. In the bookend GSHP and ASHP scenarios the share of heating provided by renewable gas drops to zero, and in the "mixed scenario, the share of heating provided by gas drops to one half of the current share. Gas infrastructure planning and investment decision making should be informed by and account for these potential declines in the share of space heating provided by gas.

FIGURE 22: HEATING SHARES BY FUEL (NUMBER OF BUILDINGS) CURRENT SHARES VS MIXED SCENARIO (2050)

Figure 5: Economics of Residential Space Heating Decarbonization Options[11]

The next section provides additional detail related to the resource base, and estimated costs for renewable gas.

Resource and Costs for Renewable Gas

A 2019 Study conducted by ICF International for the American Gas Foundation includes national and state-level estimates of RG potential by 2040 under low and high development

[11] The Brattle Group, HST Study, Executive Summary, page 2.

scenarios.[12] Table 1 summarizes Rhode Island's estimated 2040 potential as presented in Appendix A of the study.

Table 1: Estimated Rhode Island RNG Achievable Potential 2040

	Anaerobic Digestion				Thermal Gasification				
	LFG	Manure	WRRF	Food Waste	Ag Res	Forest Res	Energy Crops	MSW	Total
2040 Low	1.447	0.008	0.103	0.128	0.001	0.126	0.007	1.037	2.857
2040 High	2.357	0.016	0.15	0.224	0.003	0.251	0.007	2.337	5.345

The values in Table 1 do not represent economic potential. They are technical achievable potential estimates accounting for resource base, adoption rates and conversion technologies. It is notable that Rhode Island's technically achievable potential is heavily concentrated in two resource categories, with more than 85 percent of the identified potential in both the high and low cases coming from the combination of landfill gas and thermal gasification of municipal solid waste.

The high and low scenario results in the AGF study also indicate that thermal gasification is only expected to make meaningful contributions to the RG potential after 2030. Some further concerns with the pursuit of gasification are addressed in the next section of this whitepaper. In any case, Rhode Island's estimated technical achievable potential by 2040 for RG from anaerobic digestion and thermal gasification is only a small fraction (2.9% low, and 5.5% high) of 2019 statewide gas demand as illustrated in Figure 6.

[12] American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, Prepared by ICF, December 2019.

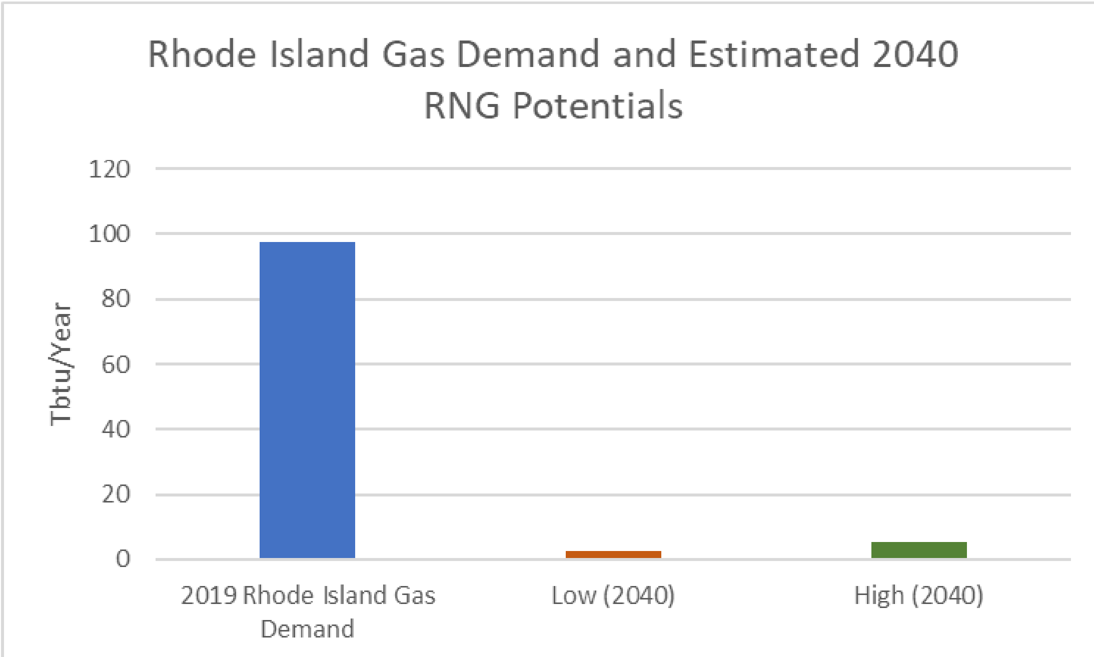


Figure 6: Rhode Island Gas Consumption and Estimated RG Potential by 2040

These scenario results, coming from a study sponsored by the gas industry, indicate that the RG technical resource potential from anaerobic digestion and thermal gasification is very limited, and even by 2040 it only has the potential to replace a small fraction (2.9% to 5.5%) of current gas volumes.

Cost estimates for RG production are summarized in Figure 7 from the HST study.[13] These include estimates from the AGF sponsored study, including costs for anaerobic digestion and thermal gasification processes, as well as for Power to Gas. The latter uses renewable electricity and electrolysis to create hydrogen which can then be used directly as an industrial process fuel or be processed via methanation to produce pipeline decarbonized gas.

[13] The Brattle Group, Rhode Island Heating Sector Transformation Study, Figure 21, page 36.

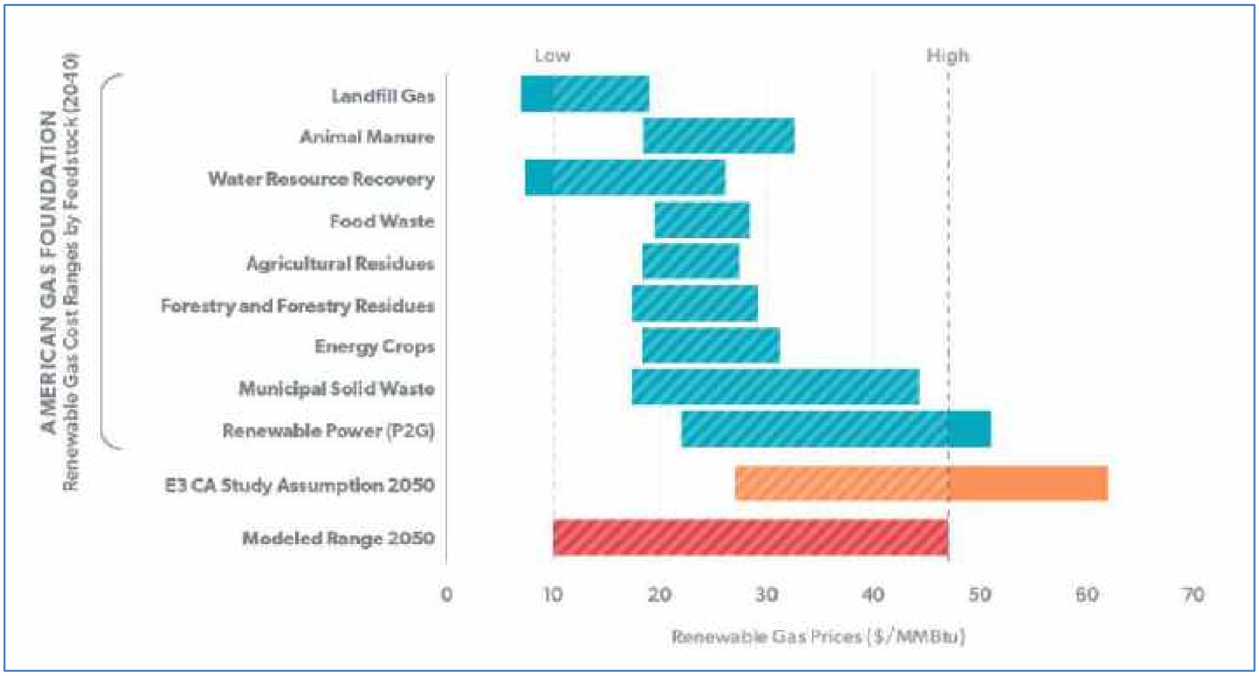


Figure 7: Cost Estimates for Decarbonized Gas Production

Ranging above $20 per MMBtu for most options and with top ends exceeding $50 per MMBtu for Power to Gas, these estimates, again mostly from a study sponsored by the gas industry, make it clear that decarbonized gas options are expensive, both in comparison to conventional gas costs, but also in comparison to alternatives such as electrification and efficiency. This further underscores the importance of careful comparison of alternatives when evaluating proposals for investments in gas infrastructure, and for considering shorter depreciation periods for the cost recovery associated with any such investments.

Additional Concerns on Methanation

National Grid's FY 2022 ISR Plan is only a portion of the longer-term 20-year proactive main replacement program, the latter of which addresses the eventual replacement of leak prone elements of the gas distribution system.[14]

[14] National Grid ISR FY 2022 plan, page 30 lines 10-18.

The integrity and safety of gas infrastructure is important for safety, environmental and economic reasons. Fugitive emissions of methane have a high global warming potential, particularly over near-term horizons, and they contribute to harmful local air pollution including the formation of ground level ozone.[15] The need for a 20-year plan to address the existing "leak prone" distribution infrastructure indicates even new sources of RG are available, they are also prone to leakage, and do not avoid fugitive emissions and the associated problems. As noted above, the accurate accounting of gas leakage may, by itself increase the state's total GHG emissions by 45%.

Increasing research and advocacy suggests that rather than investing in or supporting new resource streams of methane, for example from the gasification of agricultural residues, efforts to reduce or contain existing sources of methane through alternative management practices may be more prudent.[16]

Targeting Applications for Renewable Gas

The heating sector transformation (HST) report cited earlier provides some discussion of decarbonization options for process heat. Rhode Island has limited heavy industry with highly intensive process heat needs, and much of the industrial energy consumption may be used for lower temperature space and water heating. However, where there are industrial processes requiring higher temperatures, these can be good strategic targets for the use of decarbonized gas or liquid fuels. Heat pump technologies, while they are capable of meeting space and water heating loads, are not able to meet higher temperature process heat needs. Recognizing that solutions for industrial processes will be highly specific to a given facility and process, the use of decarbonized liquid or gas fuels for process heating may avoid the need for new capital investments to retool the production process, when they can serve as a "drop-in" fuel replacement for conventional fossil-

[15] Stockholm Environment Institute and Brown University Climate & Development Lab, *Deeper Decarbonization in the Ocean State: The 2019 Rhode Island Greenhouse Gas Reduction Study*, September 2019, discusses the implications of updated methane leakage rates and consideration of 20-year global warming potential for methane emissions at page.
[16] For examples see: Earth Justice and Sierra Club, Rhetoric Vs. Reality: The Myth of "Renewable Natural Gas" for Building Decarbonization, July 2020., and
RMI, A New Approach to America's Rapidly Aging Gas Infrastructure, available here.

based fuels. Industrial process heat conversions to use RG or Power to Gas are likely to be site-specific, may not require pipeline distribution service, and be phased in over a period of decades.

As discussed above the resource potential, and therefore the volumes, of RG are expected to be significantly less than conventional fossil supplies, and to be much more expensive. Matching these limited and more expensive supplies with industrial applications for which there are not viable alternatives will help to maximize the value of any decarbonized fuels, and this may in turn support their higher production costs. Conversely, planning and investing in infrastructure so the more limited and more expensive supplies of RG are used broadly for lower temperature space and water heating requirements is less likely to contribute to meeting GHG reduction goals and less likely to maximize the value of any decarbonized fuels.

Targeted high value industrial uses may also be more geographically concentrated than general space and water heating loads, permitting more targeted ISR type planning for strategic replacement, and pruning, of gas infrastructure. Using RG for electric generation to help balance and support an increasingly renewable grid is another potential high value application. Electric generation use would also be likely to be geographically concentrated and help to limit and prioritize gas infrastructure system upgrades.

Targeting and Coordinating Gas Infrastructure Investments

There is a need to consider ISR plan and other gas infrastructure investments in the context of the issues above and compared to alternatives. The alternatives should include selective targeting and pruning of the gas infrastructure to support high value uses. For example, investments in upgrading a pipeline for a branch with loads dominated by space and water heating loads might be avoided through a strategic electrification program. If branches that can be retired are identified the amount of the pipeline needing safety and reliability upgrades may be reduced.

There is a potential dynamic relationship between investments in the gas and electric systems. A reduction in gas infrastructure investments may require increasing investment in the electric distribution system, say for example, to meet the needs of building and transportation electrification. Specific gas ISR investments may be prudent and necessary, but the they are best considered within this type of more holistic framework.

The potential for coordinating distribution system planning and investment in Rhode Island is enhanced by National Grid being responsible for both gas and electric distribution. The strategies outlined in this whitepaper may help to avoid un-coordinated or redundant investments.

Depreciation Period for Gas Infrastructure Investments

Depreciation periods, for gas infrastructure or other investments, should match the anticipated lifetime over which the assets will be used and useful. This reduces the risk of stranded costs and provides an appropriate estimate of the rate impacts required to recover costs from ratepayers. In general, longer depreciation periods reduce near-term rate impacts by stretching out the cost recovery, so an investment with a longer depreciation period may appear to be more palatable to gas customers.

In this whitepaper we have reviewed factors likely to limit the future use of gas infrastructure. Meeting Rhode Island's greenhouse gas emissions reduction targets, the cost and resource potentials for renewable or decarbonized gas, and the benefit of targeting any future such gas use to highest value applications all point towards reduced reliance on gas infrastructure. We therefore recommend utility commissions should apply shorter depreciation periods for gas infrastructure investments, and in no case longer than 20 years. This reduces the risk of stranded costs, and more accurately reflects the near-term rate impacts of investments under consideration.

As an example, Figure 8 illustrates a twenty-year versus a thirty-three-year depreciation period for an investment of $180 million, the same size as that proposed by the FY 2022 ISR plan, using a declining balance method and a 10% salvage value.

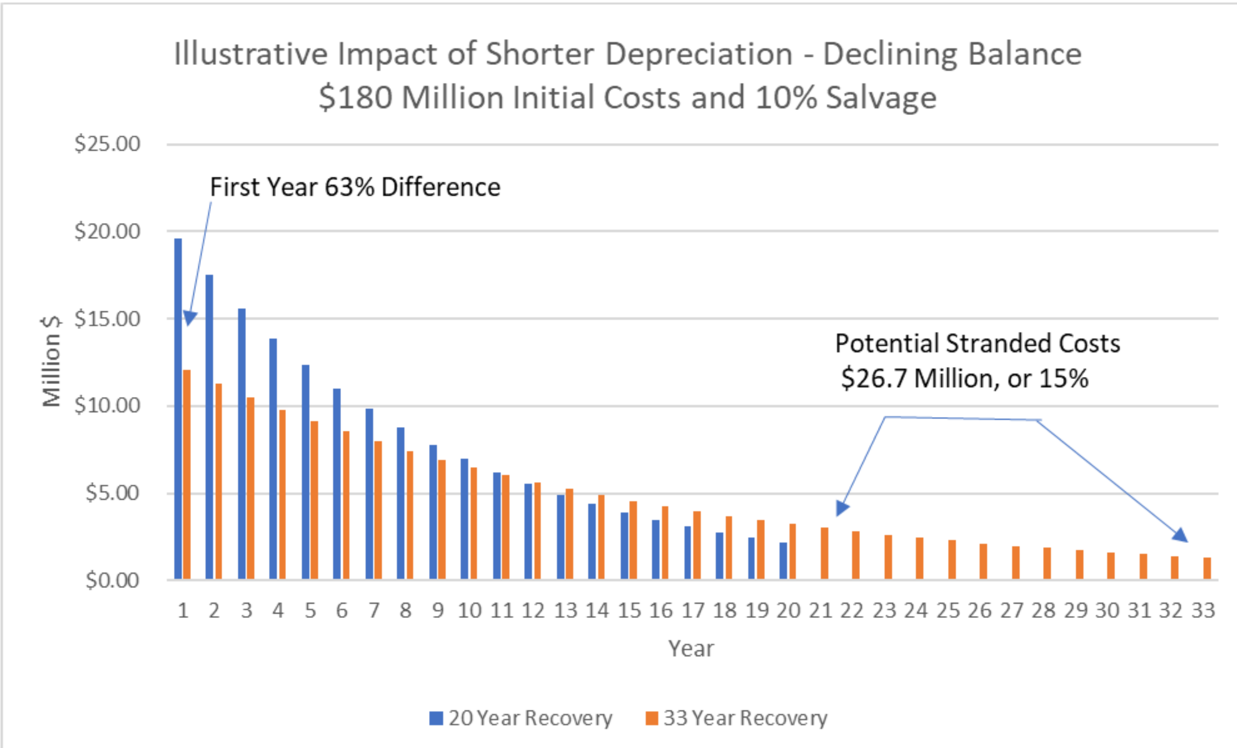


Figure 8: Cost Recovery Comparison for Twenty- and Thirty-Three-Year Depreciation Periods

At the end of twenty years the shorter depreciation schedule (blue bars) will have recovered all costs. To do so, it has higher annual cost recovery for each of the first ten years in comparison to the 33-year deprecation period (orange bars). In the first year, the required cost recovery is 63% higher for the 20-year depreciation period. At the end of 20 years, the case with the longer (33 years) depreciation period has $26.7 million of costs yet to be recovered, equivalent to 15% of the initial investment.

We suggest that the appropriate depreciation period needs to be carefully assessed by commissions in each case as the climate landscape continues to change, and that twenty years should be a cap for new gas infrastructure investments. The shorter deprecation along with more comparative analysis of alternatives and coordinated strategic planning for both gas and electric infrastructure investments are important steps to help Rhode Island meet future GHG emissions reduction targets, to protect ratepayers and shareholders, and provide greatest benefits to the state's economy.

Conclusions and Recommendations

- Continued broad based reliance on gas infrastructure beyond 2050 is incompatible with achievement of the state's GHG emissions reduction goals.
- RG has limited resource potential, and high costs. It doesn't make sense to maintain gas infrastructure on the assumption that we will switch to RG at scale in the future.
- Targeted high value applications of RG may be justified, but they are likely to require a much smaller gas distribution infrastructure.
- We should not be amortizing costs of new gas infrastructure over periods that extend beyond twenty years.
- Options to target and limit the amount of gas infrastructure investment should focus on highest value uses. These may result in concentrated geographic replacement and upgrades.
- Opportunities for greater coordination in planning and investment for gas and electric distribution system should be pursued.

CLF-1-3

nationalgrid

Aquidneck Island Long-Term Gas Capacity Study

Prepared by National Grid

September 2020

Table of Contents

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.

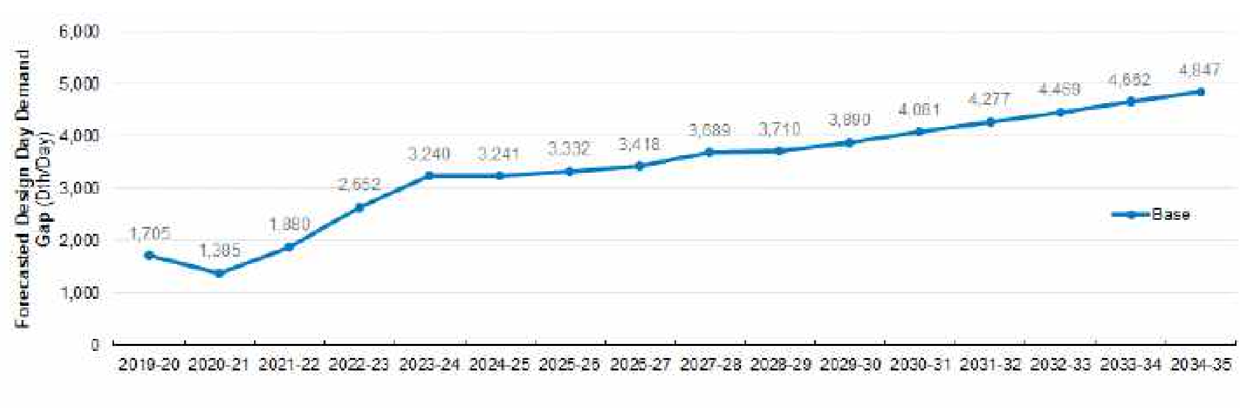
This change in approach effectively reduced the AGT capacity available to Aquidneck Island compared to the capacity available in the past. The lack of flexibility also created an immediate gas capacity constraint when projected demand is at its highest on the island under extreme cold conditions, including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

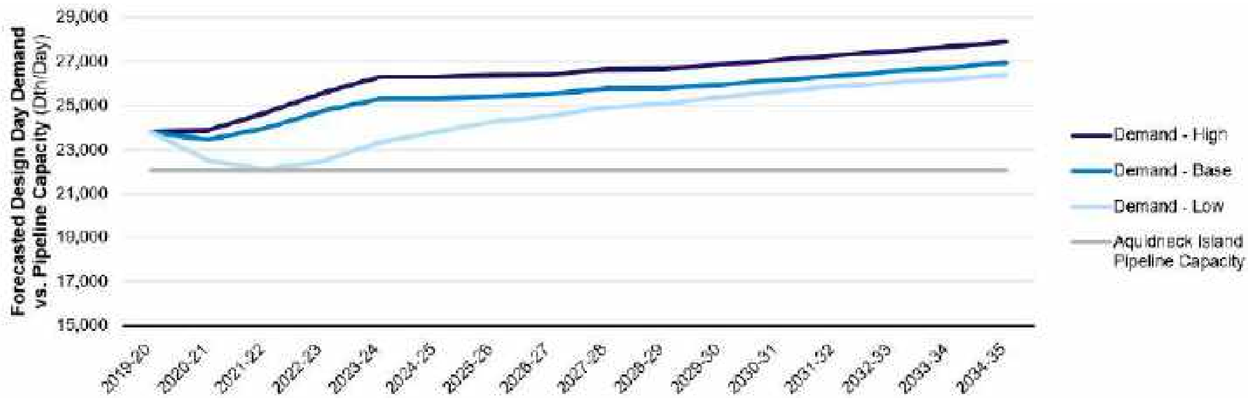
Rhode Island is a national leader in energy efficiency, ranked third in the nation in the most recent *2019 State Energy Efficiency Scorecard* report from the American Council for an Energy-Efficient Economy. The Company's long-term gas demand forecast reflects the effects of energy efficiency including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

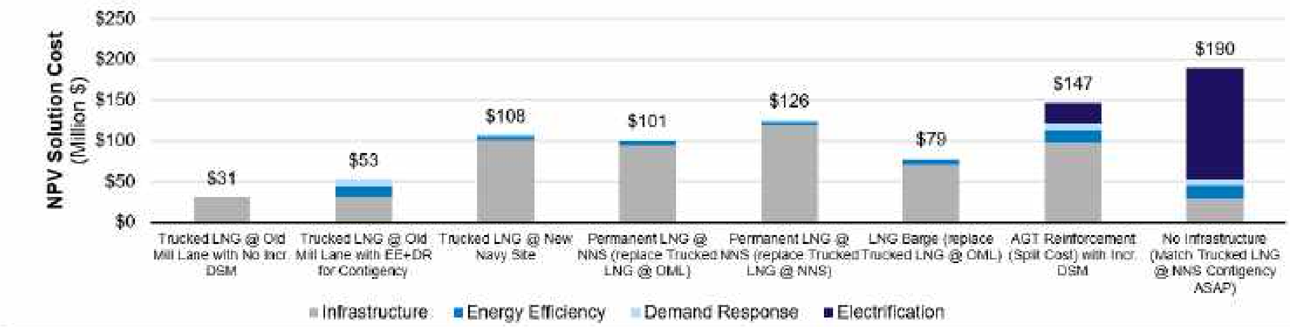
Figure 3 below presents the cumulative net present value (NPV) of estimated costs for the different approaches through the winter of 2034/35. For this cost analysis each of the infrastructure options has been paired with complementary incremental demand-side programs.[6]

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.

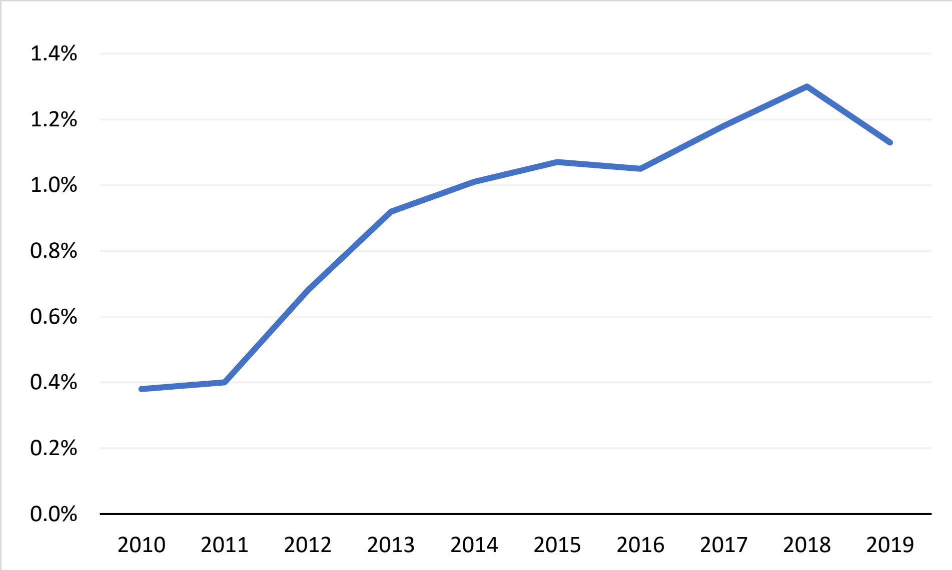
5. Projected Natural Gas Demand through 2034/35 on Aquidneck Island

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.

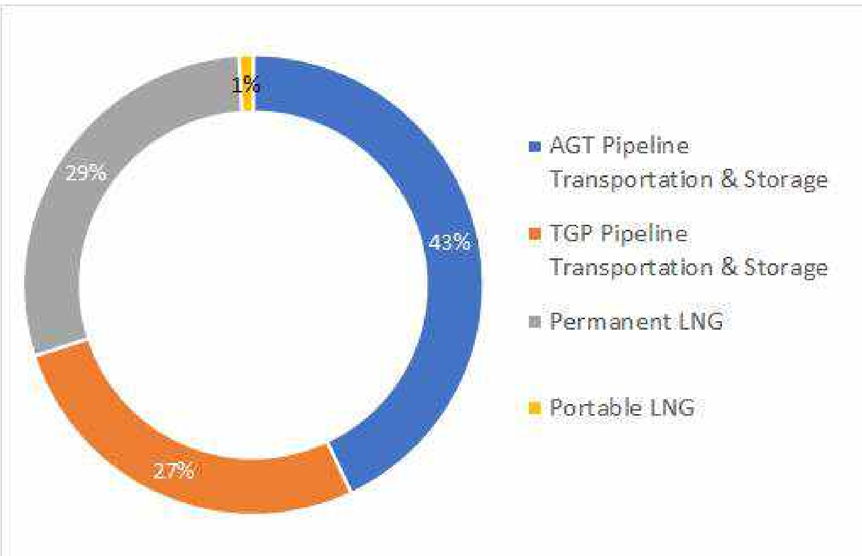
AGT is a Northeastern interstate natural gas pipeline that extends from New Jersey up into Massachusetts. The AGT G-system is a lateral that branches off of the AGT mainline in southern Massachusetts and extends south and east to serve parts of Rhode Island and

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

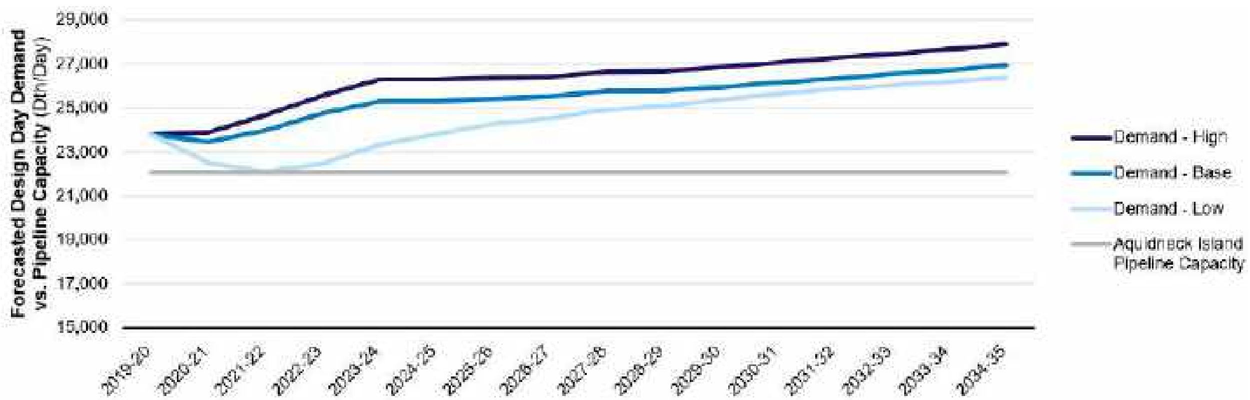
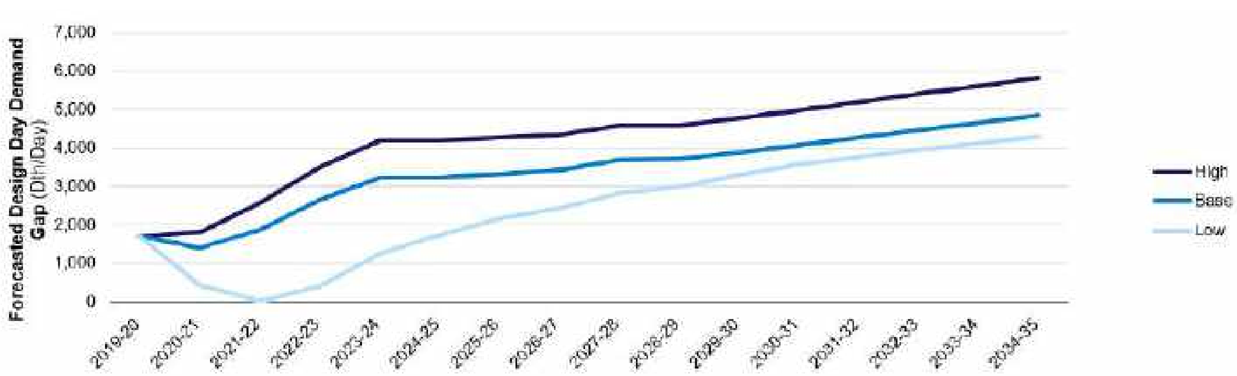


Figure 8: Forecasted Gap Between Design Day Demand and Available Pipeline Gas Capacity for Aquidneck Island



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

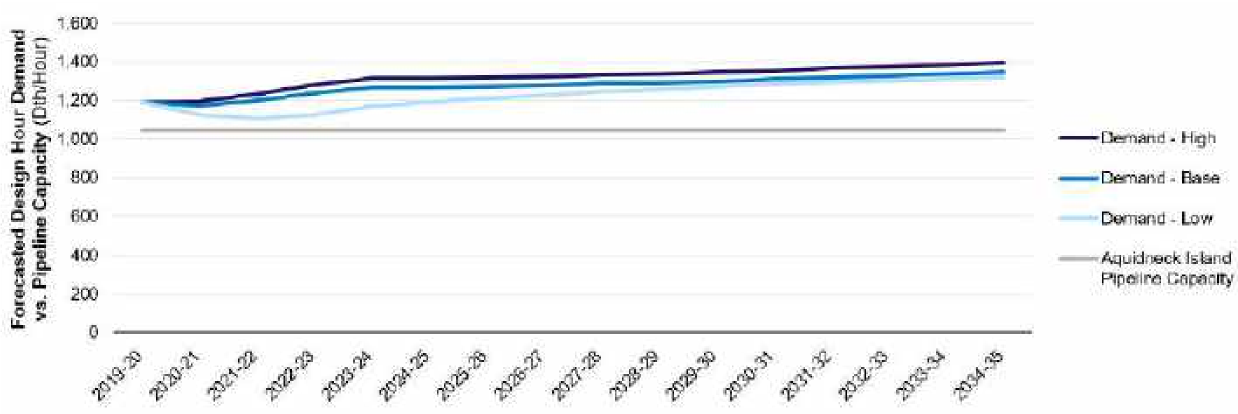
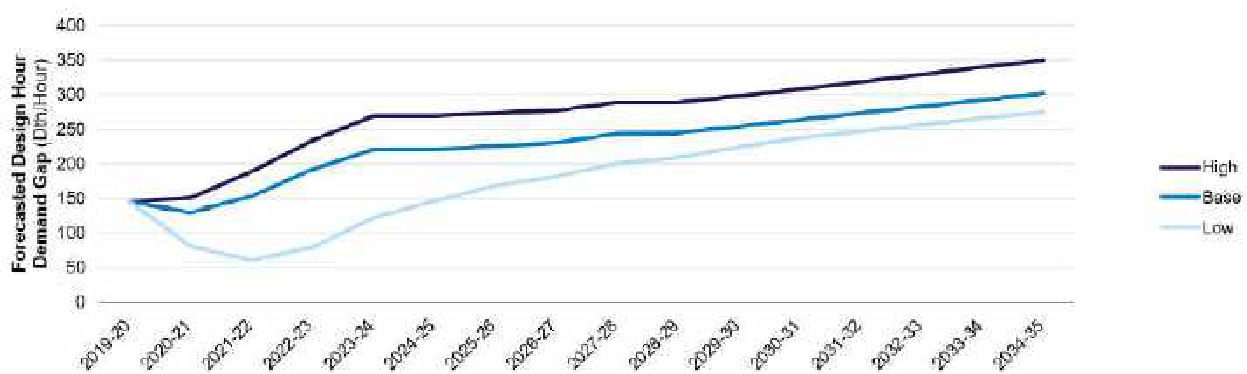


Figure 10: Forecasted Gap Between Design Hour Demand and Available Pipeline Gas Capacity for Aquidneck Island



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.

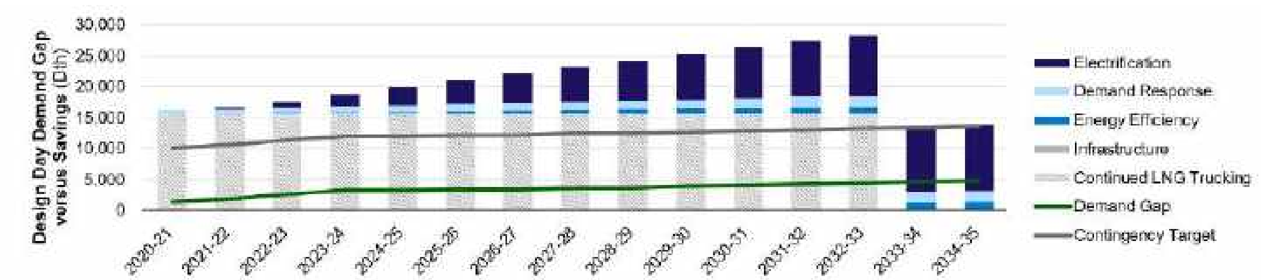
Only gas demand reductions on Aquidneck Island itself can help address the capacity constraint need. Without an AGT project implemented, gas demand reductions elsewhere in Rhode Island supplied from AGT cannot free up gas to deliver to Aquidneck Island owing to the inability to flow more gas to Aquidneck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

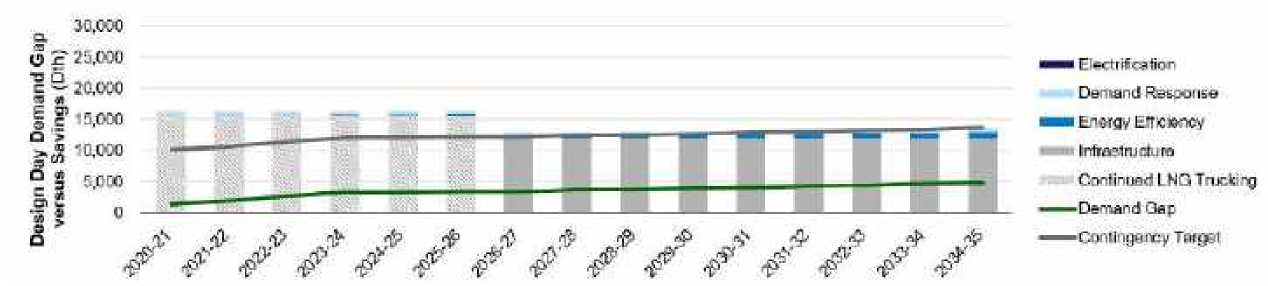
- A portable LNG solution on an indefinite basis – this option would create the infrastructure needed to support portable LNG at the new Navy site and rely on that portable LNG solution indefinitely in lieu of the portable LNG at Old Mill Lane
- A portable LNG solution on an interim basis to be replaced 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 contingency Trucked LNG at the New Navy Site would provide upon completion in 2024-25, held constant with forecasted growing demand.

9.4. AGT Project

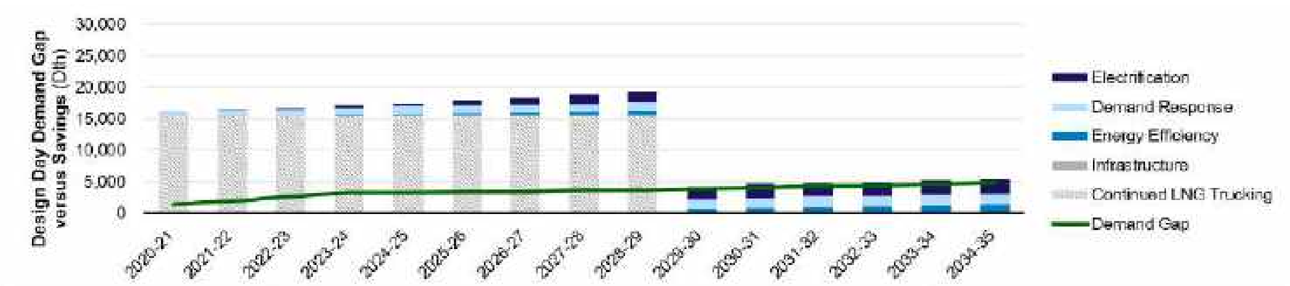
The details of an AGT project are yet to be determined and could range from a more narrowly targeted system reinforcement project to address needs on Aquidneck Island to a broader system expansion project that would address regional needs of multiple gas utilities. The scope of the project would determine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

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

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

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

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



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

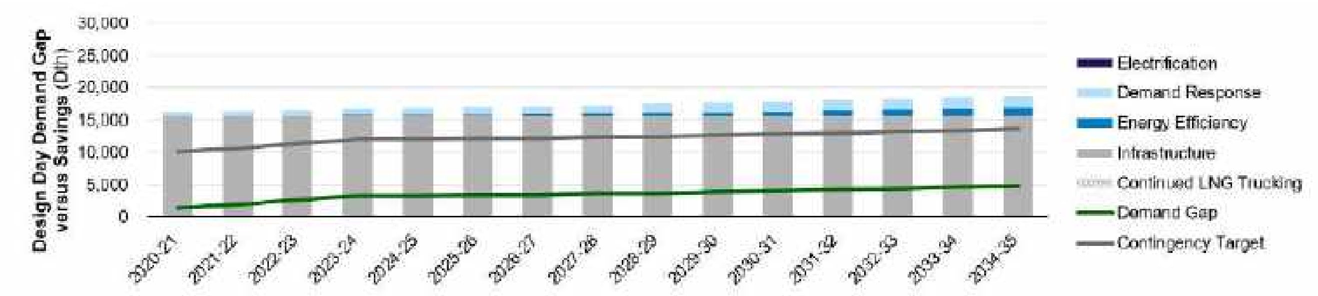
9.5. Continue to Use Old Mill Lane Portable LNG

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

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

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

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



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

10. Evaluation of Approaches to Meet Needs

10.1. Multi-Criteria Evaluation of Approaches

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

- **Timing** – The approaches differ in terms of how long they take to replace the portable LNG at Old Mill Lane if ever, with a purely non-infrastructure approach taking by far the longest at an estimated 13 more winters. Several of the new LNG solutions can potentially phase out Old Mill Lane portable LNG after only three more winters.

- **Cost** – The approaches vary substantially in cost. Cost is treated separately below. Given the early stage and lack of detail on any potential AGT pipeline project, there is no cost information available for this option; however, this option would address the need on Aquidneck Island among other regional needs, so the cost would not be directly comparable to options that solely meet the needs on Aquidneck Island.

- **Reliability** – All of the options can provide the reliability needed for Aquidneck Island. Every option can face challenges to reliability, such as upstream disruptions on gas pipelines, the operational complexity of LNG options, and the need for effective program design and successful track record of gas demand response. The gas utility industry has long used portable LNG as a stop-gap solution. National Grid's experience in portable pipeline supply operations and recent increased usage of portable LNG, as well as portable compressed natural gas (CNG), across its service territories to meet peak customer demand has led the Company to conduct rigorous process safety assessments at each site as well as of transportation activities and implement risk mitigation measures through design improvements and operating plans. This analysis coupled with years of operating experience in portable LNG and CNG operations has provided confidence in the overall reliability of these options.

- **Community Impacts** – The Old Mill Lane portable LNG option rates lowest because of existing concerns from nearby residents. Because none of the other options involve operations within as close proximity to residential neighborhoods, other options may rate more highly on community impacts. However, any of the other infrastructure options could engender similar or even greater community concern from different community members. The non-infrastructure option would require unprecedented levels of effort by community members to participate in adopting energy efficiency measures like home weatherization and home heating system replacements; moreover, the non-infrastructure option would require continued reliance on Old Mill Lane portable LNG for an estimated 13 more winters, with associated continued community impacts.

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

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

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

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

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

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

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

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

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

		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.

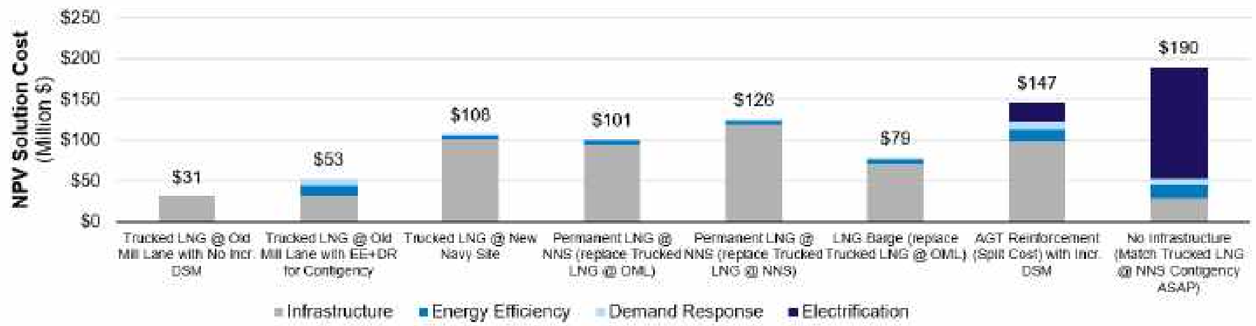
The Company also looked at the cost of the options under the high and low long-term gas demand scenarios but found no material change in the relative costs.

[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%

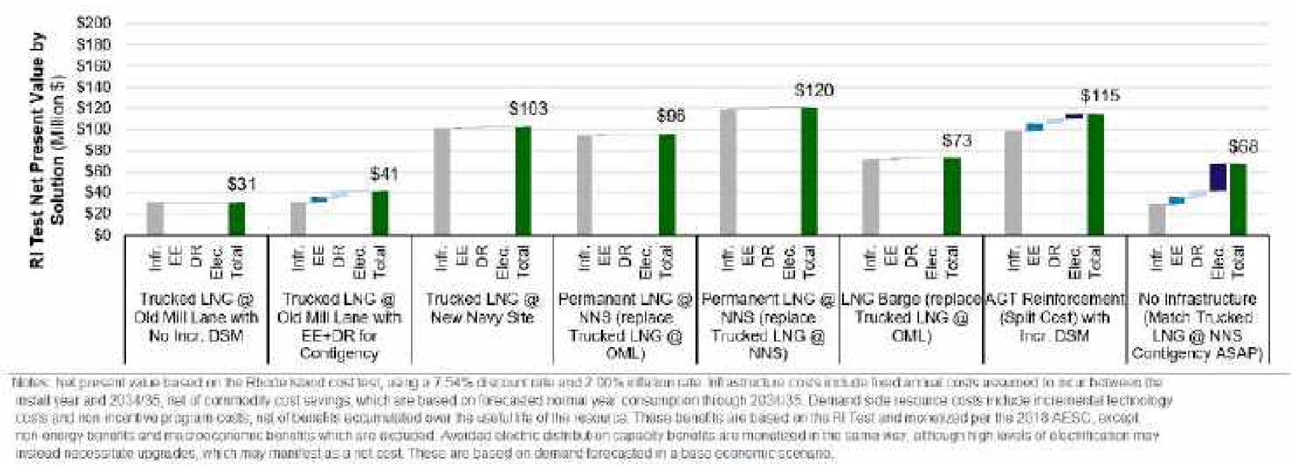
Non-Infrastructure	Incremental Gas Energy Efficiency, Gas Demand Responses, and Heat Electrification	$63	3.7%

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



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

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

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

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

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

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

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

10.6. Risk and Reliability Impacts of Approaches

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

11. Decarbonization of Heating

11.1. Decarbonization Pathways for Heating

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

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

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

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

11.2. A Hydrogen Hub on Aquidneck Island

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

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

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

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

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

11.3. Decarbonization Considerations for the Potential Long-Term Solutions

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

Table 28: Decarbonization Implications and Considerations

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

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

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

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

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

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

13. Stakeholder Input and Next Steps

13.1. Stakeholder Engagement

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

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

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

13.2. Next Steps to Address Aquidneck Island Needs

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

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

13.3. Optionality and a Final Long-Term Solution

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

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

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

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

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

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

14. Technical Appendix for Non-Infrastructure Resources

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

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

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

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

Incremental Energy Efficiency Assumptions

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

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

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

Scenario Composition

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

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

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

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

Energy Savings

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

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

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

Annual Savings

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

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

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

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

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

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

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

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

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

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

Avoided Double Counting of Savings

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

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

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

Measure Life

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

Table A-3: Measure Life (years)

	Envelope	HVAC
Residential	20	19
Commercial	25	15

Participation: Program Ramp-Up and Customer Adoption

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

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

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

Basis for Customer Adoption

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

Weatherization/Envelope

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

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

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

[1]Not incremental to base case

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

Table A-5: Cumulative Weatherization Completions in 2034

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

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

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

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

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

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

Source: National Grid estimate for residential and commercial customers.

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

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

HVAC

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

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

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

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

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

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

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

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

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

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

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

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

[1]Not incremental to base case in 2026.

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

High Efficiency Boilers: Early Replacements

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

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

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

[1]Not incremental to base case

High Efficiency Gas Systems

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

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

Other HVAC Measures

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

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

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

Annual Thermostat Installations	
Base	185
Moderate case	326
Aggressive case	479

[1]Incremental to base case

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

Program Costs

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

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

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

Equipment Cost Incentives

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

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

Table A-11: EE Incentives per Participant

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

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

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

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

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

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

Pre-weatherization Cost Analysis

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

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

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

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

Source: National Grid EE program data.

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

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

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

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

Summary

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

Table A-15 – Summary of Incremental EE Assumptions

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

Incremental Demand Response Assumptions

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

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

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

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

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

Adoption

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

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

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

Savings

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

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

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

Costs

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

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

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

Summary

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

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

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

Incremental Electrification Assumptions

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

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

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

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

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

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

Table A-17: Heat Pump Electrification Assumptions

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

The assumptions surrounding this program are discussed below.

Ramp-Up and Customer Adoption

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

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

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

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

Savings

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

Table A-18: Summary Electrification Technology and Cost Assumptions

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

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

Costs

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

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

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

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

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

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

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

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

Summary

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

Table A-20: Summary of Incremental Electrification Assumptions

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

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January 27, 2023

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-42-NG – Issuance of Advisory Opinion to EFSB re RIE Application to Construct an LNG Vaporization Facility on Old Mill Lane, Portsmouth, RI Responses to CLF Data Requests – Set 1 (Batch 1)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company (the "Company"), I have enclosed the Company's responses to the Conservation Law Foundation's ("CLF") First Set of Data Requests (Batch 1) in the above-referenced docket. The Company requires additional time to respond to Data Request CLF 1-9, and CLF's counsel has consented to a one week extension. Please note that Attachments CLF 1-7, CLF 1-12 and CLF 1-14 are excel files that are being provided electronically.

Thank you for your attention to this matter. If you have any questions, please contact me at (401) 709-3351.

Sincerely,

George W. Watson III

Enclosures
cc: Docket 22-42-NG Service List

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon

January 27, 2023
Date

Docket No. 22-42-NG – Needs Advisory Opinion to EFSB regarding Narragansett Electric LNG Vaporization Facility at Old Mill, Portsmouth, RI
Service List update 12/20/22

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Matt Sullivan (Green Dev)	ms@green-ri.com;	

CLF 1-1

Request:

Please provide the Company's peak hour demand forecast for the territory to be served by the proposed facility.

a) Include the forecast Design Day and Design Hour demands underlying the forecast peak hour demand.

b) Please explain how the Company has taken climate change into account when calculating the Design Day and Design Hour demands. If climate change was not considered, please explain why it was not considered.

c) Please explain how the Company has taken any differences between the climate of Aquidneck Island and mainland Rhode Island into account when calculating the Design Day and Design Hour demands. If any such differences were not considered, please explain why they were not considered.

Response:

a) Please see the Company's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2021/22 to 2025/26 attached to the Siting Report as Appendix A and the Aquidneck Island specific forecast provided in response to Division 1-13.

b) Climate change is considered in the retail and wholesale forecasts to the extent its effects are present in the historical data. Although average temperatures have risen in recent history, the Company is not aware of evidence that supports declining trends in the severity or frequency of extreme cold weather events. Therefore, Design Day standards are not subject to change based on warming temperatures.

c) Aquidneck Island does not have sufficiently reliable historical weather data to create a demand forecast. Design Day and Design Hour demands are forecasted as a function of weather measured at the TF Green Airport weather station (PVD) in Providence, Rhode Island. Because the weather on Aquidneck Island is highly correlated with the weather in Providence, there is no need to consider weather differences between the two locations.

Prepared by or under the supervision of: James M. Stephens, Theodore E. Poe, Jr., and Stuart A. Wilson

---

CLF 1-2

Request:

Witness Porcaro's testimony on page 7, lines 19-20 indicates that the current supply demand-gap is approximately 145 Dth/hr.

Please provide:

a) analysis supporting the estimate of the current supply-demand gap, and

b) analysis supporting the forecast for the supply-demand gap in future years.

Response:

a) The load forecast data provided by the forecasting team is used during the creation of the Synergy gas models each year. A customer load profile is created through this model development process and analyzed within the Synergy models to determine supply-demand data. The load profile for the anticipated winter 2023-2024 at the Portsmouth Gate Station can then be shown based on five-degree increments within a normal versus design winter. The Company's 68 HDD[1] (-3 degrees Fahrenheit average daily temperature) is the Company's design winter model to determine a five percent peak hour gas demand for the design day. The contracted Maximum Daily Quantity ("MDQ") with Algonquin Gas Transmission, LLC at Portsmouth Gate Station is calculated for an hourly rate, or 1,045 dekatherms per hour ("dth/hr"), and the model data for Winter 2022/2023 shows a demand of 1190 dth/hr. This would determine a shortfall of 145 dth/hr on the peak hour of a design day at the Old Mill Gate Station. This 145 dth/hr would be the recommended amount of gas supply from the portable LNG site to maintain the contractual MDQ at the Gate Station.

b) Please refer to the Company's response to Division 1-13 and the attachments thereto for the supporting information to the Company's Aquidneck Island wholesale forecast, including its design hour.

c) The Company uses the latest load forecast to look at the following years by a general growth percentage per year. The simple equation to determine the shortfall (Demand

[1] Heating degree day ("HDD").

CLF 1-2, Page 2

– MDQ = Shortfall) is used to determine the estimated amount of portable LNG required.

Growth Adjustment	Winter Year	Old Mill Lane Demand (dth/hr)	MDQ (dth/hr)	Shortfall (dth/hr)
1.01650	Winter 2023/2024	1210	1045	165
1.01130	Winter 2024/2025	1224	1045	179
1.00750	Winter 2025/2026	1233	1045	188
1.00620	Winter 2026/2027	1241	1045	196
1.00700	Winter 2027/2028	1253	1045	208

Prepared by or under the supervision of: Julie Porcaro and James M. Stephens

---

CLF 1-3

Request:

Witness Porcaro's testimony on page 11, lines 6-7 indicates that all non-infrastructure options require continued reliance on portable LNG at Old Mill Lane at least for the next several years.

a) How soon could non-infrastructure options eliminate the need for reliance on the Project?

b) If it is the Company's position that non-infrastructure options could not eliminate the need for reliance on the Project, please explain why.

c) Is the Project structured so that if and when the Project is no longer needed it can be discontinued?

Response:

a) The Company's original analysis of non-infrastructure solutions, as presented in the Aquidneck Island Long-Term Gas Capacity Study Prepared by National Grid September 2020 and summarized in Section 4 of the April 2022 Siting Report,[1] indicated that the continued use of Old Mill Lane to address the capacity constraint would be required until 2035. By that time, there would be sufficient modeled contributions from the demand side management programs to fully resolve the capacity constraint and mitigate the capacity vulnerability; however, non-infrastructure solutions do not fully address capacity vulnerability and will not eliminate the need for the Project.

During the summer of 2021, the Company assessed two other non-infrastructure options that would focus on resolving the capacity constraint only in line with Order No. 150 in EFSB Docket SB-2021-04. With an assumed 20% of HVAC turn over to heat electrification under a moratorium scenario and assumed 40% of HVAC turn over to heat electrification under a non-moratorium scenario as well as energy efficiency and demand response demand reductions sized equivalent to assumed

[1] Energy Facility Siting Board Project Siting Report entitled "Aquidneck Island Gas Reliability Project Old Mill Lane Portsmouth, RI" prepared for The Narragansett Electric Company by VHB dated April 2022 (the "Siting Report"), which the Company filed with the Energy Facility Siting Board on April 1, 2022, in Docket No. SB-2021-04.

CLF 1-3, Page 2

maximum potential, the Company could look to retire the current Old Mill Lane site by 2029/2030 if it was solely focused on resolving the capacity constraint.

b) Non-infrastructure solutions provide relief from capacity constraint but not capacity vulnerability, so a project of some scale will be required indefinitely to address capacity vulnerability.

c) Yes, the Project consists of portable non-permanent equipment so that, if and when the Project is no longer needed to address the capacity vulnerability and the capacity constraint, it can be discontinued.

CLF 1-4

Request:

In the Gas Long-Range Resource and Requirements Plan for the Forecast Period 2021/22 to 2025/26, attached to the Siting Report as Appendix A, the Company states at Section IV.C.3.c., page 25:

The Company has also mobilized temporary portable LNG vaporization equipment in Portsmouth to support its system on Aquidneck Island. This portable equipment provides critical pressure and supply support to Aquidneck Island should near-design day conditions arise. The Company's agreement for equipment rental continues through March 2022 with renewal rights through March 2023.

a) Under the current mobilization is the Project a service (expense) that can be discontinued if need is not ongoing?

b) As proposed, would the Project become a capital investment which will be recovered in rates over time? If so, over what time-period will the proposed capital investments will be recovered?

c) Please compare the approximately $15 million proposed capital expenditure to the annual costs incurred under the temporary mobilization.

Response:

a) Yes, the Project can be discontinued if no longer needed.

b) Yes, the Project as proposed would be a capital investment, the cost of which the Company proposes to recover through the Company's Gas Infrastructure, Safety, and Reliability ("ISR") Plan cost recovery mechanism once the Project is placed in service. The Company would continue to recover the cost of the Project through the ISR cost recovery mechanism until new base distribution rates for the Company are established at the conclusion of the Company's next general rate case, at which time the investment would be recovered in base distribution rates.

c) The costs associated with the $15 million proposed capital investment are for site work to move the equipment further into the property to address noise and visual

CLF 1-4, Page 2

impacts to the community as well as improve movement of trucks and equipment on the property and are not associated with annual costs incurred with the current temporary mobilization.

Prepared by or under the supervision of: Julie Porcaro and Stephanie Briggs

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CLF 1-5

Request:

In the winter season, under what conditions will the Project operate and provide vaporized LNG into the distribution system?

a) Will the system operate only under extreme cold conditions when the forecast temperature and HDD exceed a certain threshold? If so, what is the projected low temperature and HDD? How many days and hours are estimated on an annual basis to meet this criteria?

b) Is there a minimum level at which the system is expected to operate in all hours?

c) Please provide the anticipated winter season load profile, indicating what percent of the proposed system's capacity (in terms of Dth/hr of vaporized gas supplied to the distribution system) is expected to be utilized by hour or day for a typical season.

Response:

a) The equipment is scheduled to prepare to operate for days that are at or colder than 45 heating degree days ("HDD") (average 20 degrees Fahrenheit through the gas day) to address capacity vulnerability. The facility is further expected to be necessary to address capacity constraint when customer demand is forecasted to exceed contracted Maximum Daily Quantity ("MDQ") at the Portsmouth gate station, which occurs approximately at 62 HDD (average 3 degrees Fahrenheit). It is estimated that conditions will meet or exceed this threshold four or fewer times per winter season, each time for approximately six hours per day.

b) The equipment is not expected to operate during all hours to address capacity constraint, only during peak hours of extremely cold days when customer demand exceeds hourly gate station limitations. The equipment may be necessary to run during all hours during a capacity vulnerability event.

c) The design peak hour winter load profile is based on load forecasts. The anticipated peak hour on a design day for Aquidneck Island is 1190 dekatherms per hour ("dth/hr"). Approximately 12 percent of the gas supplied to the distribution system will be from vaporized LNG during the peak hour period. The Company's peak hour models are based off of a 68 HDD or -3 degree Fahrenheit average daily temperature. Please see the Company's response to CLF 1-2 for more information pertaining to the balance between supply and demand during design conditions.

Prepared by or under the supervision of: Julie Porcaro

CLF 1-6

Request:

Witness Olney on page 7, lines 10-11 states that:

In the case of a moratorium, the otherwise projected growth in customer demand relative to 2023 levels was assumed to be met with fuel oil powered equipment.

a) Please explain the basis for this assumption, and provide any calculations.

b) Would this assumption still hold given anticipated incentives for electrification from the Inflation Reduction Act and state programs? If so, please provide analysis or rationale for this assumption.

Response:

The following sentence and associated footnotes found on page 7, lines 12 through 15, of Company Witness Tyler Olney's Pre-filed Direct Testimony describe the basis for the assumption that projected growth in customer demand for natural gas relative to 2023 levels would be met with fuel oil powered equipment:

> This assumption was made at the time because absent substantial subsidies or mandates, electrification was not a cost-effective heating option,[1] and according to U.S. Census data more households in southeast Rhode Island currently use fuel oil than any other heating source.[2]

As noted in footnote 1, this analysis pre-dated the Inflation Reduction Act and associated state programs. The impact of these programs is uncertain at this time because they are in the early stage of implementation.

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[1] See, e.g., Rhode Island Strategic Electrification Study accessible here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5.-Rhode-Island-Strategic-ElectrificationStudy.pdf. Note that this analysis was performed prior to the announcement of Rhode Island's High-Efficiency Heat Pump Program and the passing of the federal Inflation Reduction Act.

[2] US Census 2019 and 2021 American Community Survey Public Use Microdata, see: https://data.census.gov/mdat/#/search?ds=ACSPUMS1Y2019&rv=ucgid,HFL&wt=WGTP&g=7950000US4400300.

Prepared by or under the supervision of: Tyler Olney

CLF 1-7

Request:

Please provide the analyses supporting the cumulative GHG savings estimates presented in Graphic 4, page 45 of the Siting Report, and the updated estimates summarized in Table 1 on page 15 of witness Olney's testimony. Please include all supporting data in Excel format with all formulas and links intact.

Response:

The specific analysis (inputs, calculations, and outputs) used to make GHG savings estimates has been extracted from the broader modeling tool to respond to this request. See the *Summary* tab of the "22-42-NG_GHGValues.xlsx" Excel file provided with this response as Attachment CLF 1-7. Note that to view the different sensitivities you must operate the toggles in cells D2-D5 of the *Summary* tab. Generally, blue-colored cells are calculations and orange-colored cells are inputs.

Prepared by or under the supervision of: Tyler Olney

<u>Attachment CLF 1-7</u>

Please see the Excel Worksheet of Attachment CLF 1-7

Prepared by or under the supervision of: Tyler Olney

CLF 1-8

Request:

Please provide the analyses supporting the emissions estimates of the non-infrastructure alternatives presented in Table 4-1, page 38 of the Siting Report, and the cumulative savings estimates presented in Table 4-4, page 45 of the Siting Report.

Response:

The emission estimates for the non-infrastructure alternatives presented in Table 4-1 of the April 2022 Siting Report correspond with the values in cells C38-I39 of the *Summary* tab of the "22-42-NG_GHGValues.xlsx" provided at Attachment CLF 1-7. The cumulative savings estimates presented in Table 4-4 of the April 2022 Siting Report are listed in cells K33-O39 of the *Summary* tab of Attachment CLF 1-7.

Prepared by or under the supervision of: Tyler Olney

CLF 1-10

Request:

Please refer to Exhibit 1 to Appendix A to the Siting Report and confirm whether any of the data in the charts therein are actual historic values. If not, please provide the Company's actual historic annual demand from 2011 through the most recently completed calendar year.

Response:

Please refer to pages 37 and 38 of Exhibit 1 to Appendix A of the Siting Report, which can be found as Attachment PUC 1-11, for a table and charts of annual retail gas demand for planning years 2011 – 2030. As this forecast was finalized in June of 2021, actual historic annual demand data would span planning year ("PY") 2011 through PY 2020.

A planning year spans from November of the year prior through October of the planning year. Annual gas demand is listed for Residential Non-Heating (RNH), Residential Heating (RH), CI_Sales (commercial/industrial sales), FT-1 commercial/industrial transportation, FT-2 commercial/industrial transportation, and Other customers.

PY 2021 would be partly actuals and partly forecast. PY 2022 through PY 2030 would be forecast data.

Because of billing lag, the annual demand for calendar year 2022 is not yet available. Please see the Company's response to CLF 1-12 for the most recent actual customer demand data for Aquidneck Island.

CLF 1-11

Request:

Please refer to page 7, lines 12-14 of witness Kirkwood's testimony where it is stated:

The Project at Old Mill Lane is intended to serve both purposes: a backup supply as a secondary source intended to address capacity vulnerability, and also peak shaving to address the capacity constraint to Aquidneck Island.

Please explain how the Company defines and distinguishes a "capacity vulnerability" from a "capacity constraint."

Response:

The Company distinguishes between "capacity vulnerability" and "capacity constraint" (also referred to as "capacity shortfall") on the first page of the Introduction section of the Siting Report[1] excerpted below:

> The Project is needed to address capacity vulnerability and capacity constraints to the Distribution System. Capacity vulnerability has two aspects. First, the Company faces seasonal vulnerability from unexpected upstream disruptions that could limit the flow of natural gas from the interstate pipeline below levels needed to meet demand. Second, capacity vulnerability occurs when AGT disrupts capacity in order to inspect and maintain the upstream transmission pipeline. The Project would protect the Distribution System against these vulnerabilities. Finally, the Project also addresses the capacity shortfall that may occur during each winter season when there exists a gap between the natural gas demand and the available natural gas capacity to Aquidneck Island on extremely cold days.

For more information regarding capacity vulnerability and capacity constraint on Aquidneck Island, and how the Project addresses these concerns, please refer to Section 2 of the Siting Report.

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[1] Energy Facility Siting Board Project Siting Report entitled "Aquidneck Island Gas Reliability Project Old Mill Lane Portsmouth, RI" prepared for The Narragansett Electric Company by VHB dated April 2022 (the "Siting Report"), which the Company filed with the Energy Facility Siting Board on April 1, 2022, in Docket No. SB-2021-04.

Prepared by or under the supervision of: Julie Porcaro

CLF 1-12

Request:

Please refer to page 6 of witness Porcaro's testimony and provide the hourly demand/offtake for Aquidneck Island from 2015 through the most recently completed calendar year.

Response:

Please see Attachment CLF 1-12 for the requested information. Because of the size of this attachment, it is being provided in Excel format.

Prepared by or under the supervision of: Julie Porcaro

Attachment CLF 1-12

Please see the Excel Worksheet of Attachment CLF 1-12

Prepared by or under the supervision of: Julie Porcaro

CLF 1-13

Request:

On page 6 of her testimony, witness Porcaro refers to the supply loss that occurred on January 19, 2019. Witness Porcaro indicates on page 7 of her testimony that even though the Company will receive notice of transmission issues, the Company may have limited time to respond, "hours or minutes." Witness Porcaro also indicates on page 8 of her testimony that without the Project customers on Aquidneck Island are vulnerable to future episodes of loss of supply during critical winter months.

a) Please provide the number of transmission supply issues affecting customers on Aquidneck Island since January 19, 2019, including the date and duration of any such event.

b) Please provide the capacity provided to Aquidneck Island by the Project during these times.

Response:

a) There have been no posted transmission supply issues affecting customers on Aquidneck Island since January 19, 2019.

b) No transmission system events occurred, so the Project provided no capacity to Aquidneck Island to address gas transmission interruptions during the specified time period. On one occasion, gas day December 23, 2022, an extreme weather pattern was experienced, with unseasonably warm temperatures and rain followed by a flash of cold temperatures. The Company opted to utilize the equipment for a period of approximately four hours at a flow rate of approximately 150 dekatherms per hour.

Prepared by or under the supervision of: Julie Porcaro

CLF 1-14

Request:

On pages 15-16 of Appendix A to the Siting Report the Company references a "cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design day demand versus the cost to customers of experiencing service curtailments." Please provide the cost-benefit analysis referenced therein, in Excel format with all formulas and links intact.

Response:

Please refer to Attachment CLF 1-14 for the referenced design day cost/benefit analysis, in Excel format, that the Company performed in conjunction with its 2018 Long Range Plan submission (Docket No. 4816, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27).

Attachment CLF 1-14

Please see the Excel Worksheet of Attachment CLF 1-14

Prepared by or under the supervision of: James M. Stephens and
Theodore Poe, Jr. (pursuant to the Transition Services Agreement)

Robinson+Cole

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February 1, 2023

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-42-NG – Issuance of Advisory Opinion to EFSB re RIE Application to Construct an LNG Vaporization Facility on Old Mill Lane, Portsmouth, RI Responses to Town of Middletown's Data Requests – Set 2

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company (the "Company"), I have enclosed the Company's responses to the Town of Middletown's Second Set of Data Requests in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at (401) 709-3351.

Sincerely,

George W. Watson III

Enclosures

cc: Docket 22-42-NG Service List

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon

February 1, 2023
Date

Docket No. 22-42-NG – Needs Advisory Opinion to EFSB regarding Narragansett Electric LNG Vaporization Facility at Old Mill Lane, Portsmouth, RI
Service List update 1/27/23

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Middletown 2-1

Request:

Page 34 of the Siting Report states that a non-infrastructure option assessed in the September 2020 Long-Term Capacity Report included "maximum levels of achievable Energy Efficiency and Gas Demand Response," and further that this option "required the continued use of Old Mill Lane until 2035." Please provide a table summarizing the quantities of energy efficiency and demand response (separately) included in that alternative on a yearly basis, by customer class, as well as the cost to achieve those results.

Response:

Table 1, below, shows the cumulative design day impact of incremental energy efficiency, incremental demand response, and incremental electrification of heat under the "No Infrastructure (Match Trucked LNG @ NNS Contingency ASAP)" solution presented in the Aquidneck Island Long-Term Gas Capacity Study published in September 2020. Note that the term "incremental" in this case refers to demand-side management ("DSM") measures that would be pursued beyond assumed baseline levels of energy efficiency, demand response, and electrification already planned for, and included in, the Gas Load Forecast, meaning those baseline DSM levels are not included in Table 1.

Table 1. Cumulative Design Day Savings of Incremental DSM [Dth/day]

Season	Energy Efficiency		Demand Response		Electrification	
	C&I*	Residential	C&I	Residential	C&I	Residential
2020-21	0	0	609	0	0	0
2021-22	10	18	792	0	111	221
2022-23	32	52	884	1	326	669
2023-24	65	104	1,066	1	651	1,320
2024-25	107	174	1,155	1	967	1,930
2025-26	149	243	1,245	1	1,282	2,537
2026-27	191	312	1,244	1	1,594	3,132
2027-28	233	382	1,332	1	1,903	3,742
2028-29	275	451	1,420	1	2,210	4,292
2029-30	317	520	1,508	1	2,516	4,852
2030-31	359	590	1,595	1	2,839	5,383
2031-32	401	659	1,681	1	3,157	5,894
2032-33	443	728	1,679	1	3,469	6,390

Prepared by or under the supervision of: Brett Feldman

Middletown 2-1, Page 2

Season	Energy Efficiency		Demand Response		Electrification	
	C&I*	Residential	C&I	Residential	C&I	Residential
2033-34	485	797	1,765	1	3,788	6,868
2034-35	527	867	1,850	1	3,768	6,786

*C&I refers to commercial and industrial (i.e., non-residential) customers.

Table 2, below, shows the estimated annual incentive and administrative cost to the utility of achieving the level of incremental DSM savings presented in Table 1. Note that incremental electrification incentives were assumed to end in the final analyzed season (i.e., 2034-35), because the need for the LNG vaporization facility at Old Mill Lane was assumed to end at that time.

Table 2. Annual Utility Cost (Incentives + Administrative Expense) of Incremental DSM [$000s]

Season	Energy Efficiency		Demand Response		Electrification	
	C&I	Residential	C&I	Residential	C&I	Residential
2020-21	$0	$0	$303	$66	$0	$0
2021-22	$107	$496	$683	$89	$775	$5,153
2022-23	$241	$985	$578	$114	$1,532	$10,701
2023-24	$339	$1,491	$814	$123	$2,369	$15,766
2024-25	$433	$1,992	$697	$133	$2,365	$15,756
2025-26	$411	$1,974	$757	$142	$2,412	$16,004
2026-27	$385	$1,955	$606	$150	$2,460	$16,257
2027-28	$360	$1,931	$838	$155	$2,509	$16,512
2028-29	$330	$1,904	$894	$159	$2,560	$16,772
2029-30	$300	$1,876	$953	$162	$2,611	$17,012
2030-31	$264	$1,841	$1,014	$165	$2,837	$16,815
2031-32	$233	$1,810	$1,076	$166	$2,893	$16,977
2032-33	$203	$1,784	$916	$167	$2,951	$17,265
2033-34	$174	$1,757	$1,181	$167	$3,072	$17,558
2034-35	$137	$1,721	$1,250	$177	$0	$0

For more information about the methodology used to generate the values listed in Table 1 and Table 2, above, including important caveats about their application, see Section 14 of the 2020 Aquidneck Island Long-Term Gas Capacity Study published in September 2020.

Middletown 2-2

Request:

The Siting Report states that the non-infrastructure alternative "asks customers to adopt a technology that will likely lead to higher ongoing cost for at least the near-term future." (p. 36). Please provide the basis for this statement in the form of comparative cost estimates between natural gas-fired heating systems and heat-pump heating systems in both new construction and end-of-life replacement situations in residential and small commercial premises.

Response:

The following parameters and assumptions can be used to make comparative cost estimates for residential and small commercial customers:

- Per the U.S. Energy Information Administration ("EIA"), the average residential natural gas price in 2021 for Rhode Island was $16.18/Mcf.[1]
- Per EIA, the average residential electricity price in 2021 for Rhode Island was $0.223/kWh.[2]
- Assume 1 Mcf of natural gas is equivalent to 1.037 MMBtu of gas.
- 1 kWh of electricity is equivalent to 0.003412 MMBtu of electricity.
- Assume natural gas space heating has an Annual Fuel Utilization Efficiency ("AFUE") of 80% (1 MMBtu of gas = 0.95 MMBtu of heat output).[3]
- Assume heat pump space heating has an annual effective Coefficient of Performance ("COP") of 3.0 (1 MMBtu of electricity = 3 MMBtu of heat output).[4]

Using the above parameters and assumptions, it can be estimated that, for Rhode Island in 2021, gas heating cost $19.50 per MMBtu of heat while heat pump heating cost $21.79 per MMBtu of heat. That equates to roughly ten percent higher space heating costs for a heat pump heating system versus a gas heating system. From a unit cost perspective, new construction versus end-

[1] See data at: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SRI_a.htm.
[2] See data at: https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf,
[3] The minimum AFUE for gas furnaces is 80 percent, though Energy Star rated gas furnaces have an AFUE of at least 95 percent for Rhode Island. The latest DOE furnace-related rule making correspondence is available at: https://www.energy.gov/sites/default/files/2022-06/res-furnaces-ecs-nopr.pdf, and the Energy Star product criteria are available at: https://www.energystar.gov/products/heating_cooling/furnaces/key_product_criteria.
[4] See Table B-2 and Table C-9 of the December 2020 Rhode Island Strategic Electrification Study, available at: http://rieermc.ri.gov/wp-content/uploads/2021/01/rhode-island-strategic-electrification-study-final-report-2020.pdf.

Middletown 2-2, Page 2

of-life replacement should have no impact on the ongoing cost differential if the systems are sized the same. Note that this cost differential may close if gas prices were to increase at a relatively higher amount than electricity prices during the heating season, which is why the statement was only made in reference to the near-term future.

Middletown 2-3

Request:

The Energy Facility Siting Board's Order 150 in Docket SB-2021-04 requires the Company to include with its supplemental application "a full explanation of its forecasting methodology" to include "a complete set of schedules showing all the assumptions and calculations associated with its forecasts used in the application to justify the proposed long-term solution (…) and evaluating the EE/DR/E alternative." (page 36).

a. Does Appendix B of the Supplemental Application include any schedules showing assumptions regarding energy efficiency, demand response, or electrification? If so, please indicate which tables provide this information.

b. Does Appendix C of the Supplemental Application include any schedules showing assumptions regarding energy efficiency, demand response, or electrification? If so, please indicate which tables provide this information.

Response:

a. No. Appendix B of the Supplemental Application does not include any schedules showing assumptions regarding energy efficiency, demand response, or electrification programs. On page 9 of Appendix A, the Company discussed the impact of these three types of programs that were included in its forecast. The results of its forecast are summarized in Appendix B.

b. No. Appendix C of the Supplemental Application does not include any schedules showing assumptions regarding energy efficiency, demand response, or electrification programs. On page 9 of Appendix A, the Company discussed the impact of these three types of programs that were included in its forecast. The detailed results of its forecast are presented in Appendix C.

Prepared by or under the supervision of: Theodore Poe, Jr.
(pursuant to the Transition Services Agreement)

Middletown 2-4

Request:

On December 13, 2022, the Company submitted to the EFSB a letter from Algonquin Gas Transmission (AGT) notifying property owners of a planned pipeline maintenance project in which the existing six-inch pipeline crossing the Sakonnet River will be replaced with a new twelve-inch pipeline.

a. Did AGT submit any notification of this project directly to the Company? If so, please provide a copy of that notification and any and all subsequent correspondence between the Company and AGT regarding this project.

b. Will this project replace the entirety of the six-inch pipeline that runs approximately four miles between the Portsmouth M&R facility on Old Mill Lane and its connection point to the AGT G-system?

   i. If yes, please provide documentation of these plans.

   ii. If no, please provide documentation of any planning, assessments, or other studies that resulted in sizing of the twelve-inch replacement line.

c. If the same flow rate of gas (i.e., volume per unit time) is transported through a twelve-inch pipeline and a six-inch pipeline, what will be the relative pressures in those two lines?

d. If the project to replace a portion six-inch line with a twelve-inch line is completed, what will be the effect on the pressure of gas delivered to the Portsmouth M&R facility? What will be the effect on the pressure of gas delivered to the Company's customers on Aquidneck Island served by the Portsmouth M&R facility?

Response:

a. Yes. On September 17, 2022, AGT asked the Company if it would be available to have a discussion on September 30, 2022, regarding a potential pipeline project. The Company was informed during this September 30, 2022 meeting that AGT was

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considering upgrades to the G-lateral delivering gas to Aquidneck Island. The Company informed the Energy Facility Siting Board of this communication in a letter dated October 18, 2022.

The first direct written notice provided to the Company of AGT's plans was a copy of the letter dated December 8, 2022, which is a generic letter to landowners. Please see Attachment Middletown 2-4. The Company was also notified of the scope of the project during a meeting between AGT and Company leadership on December 7, 2022. Please also see Confidential Attachment Division 1-1-3 for a PowerPoint presentation that was provided to the Company at the December 7, 2022 meeting. The Company and AGT also met on January 24, 2023, to initiate discussions on project planning and the impact to the Company's Portsmouth meter station. At the meeting, the Company and AGT discussed the potential need for portable LNG equipment to supply the Island if a disruption of service is necessary in the course of construction activities.

b. No, the proposed scope does not replace the entire segment of single line six-inch pipeline on the G-2. The scope is for two miles out of the total four miles. Further, the scope is to replace the existing segment, not loop it, so there will still be a single line feeding Aquidneck Island. Please see Attachment Middletown 2-4 for scope and associated map provided by AGT.

c. Relative pressures can vary in the pipeline depending on transmission pipeline operation. The Company has no knowledge or input into how AGT operates its pipeline.

d. It is expected that, in general, under high demand conditions, pressures in the pipeline will improve over pressures that would be experienced with the segment as six-inch. Pressures for customers on Aquidneck Island are regulated by the Company's facilities at Portsmouth meter station and should remain generally unchanged.

Prepared by or under the supervision of: Julie Porcaro

ENBRIDGE
Algonquin Gas Transmission, LLC
890 Winter Street, Suite 320
Waltham, MA 02451
877-379-0338 *toll free*

December 8, 2022

Reference: Algonquin Gas Transmission, LLC
Natural Gas Pipeline Maintenance Project

Dear Landowner:

Algonquin Gas Transmission, LLC ("Algonquin")[1] is an interstate natural gas pipeline transmission company that maintains and operates interstate pipelines extending from New Jersey through the states of New Jersey, New York, Connecticut, Rhode Island, and Massachusetts. Our interstate pipeline network includes an existing six-inch diameter pipeline that is partially located in Portsmouth and Little Compton, Rhode Island that interconnects with Rhode Island Energy, the local gas distribution company. Our existing pipeline is the sole source of natural gas for homes and businesses on Aquidneck Island. This pipeline was originally installed in 1954.

Recently, Algonquin determined that it needs to conduct a pipeline maintenance project in Portsmouth and Little Compton that would install a new twelve-inch diameter replacement natural gas pipeline and appurtenant facilities primarily within the same easement as the existing six-inch diameter pipeline. The attached map provides information on the approximate location of the proposed work that will take place between our existing meter and regulating station on Old Mill Lane in Portsmouth and the eastern shore of the Sakonnet River in Little Compton (the "Project"). After the replacement pipeline is installed and operational, Algonquin intends to abandon in place its existing six-inch pipeline by filling it with grout.

To help us refine the scope of the Project, company representatives are beginning to collect and evaluate information necessary to determine the design of the Project. Our intent is to proceed in a way that has the least overall impact on our neighbors and the environment, while balancing constructability considerations for the installation of the replacement pipeline and appurtenant facilities. You are receiving this letter because your property is near the study corridor that is being reviewed to finalize the design of the Project. You may see our representatives in the field undertaking civil, environmental, cultural or geotechnical surveys as we evaluate the route for the installation of the replacement pipeline. These survey activities will

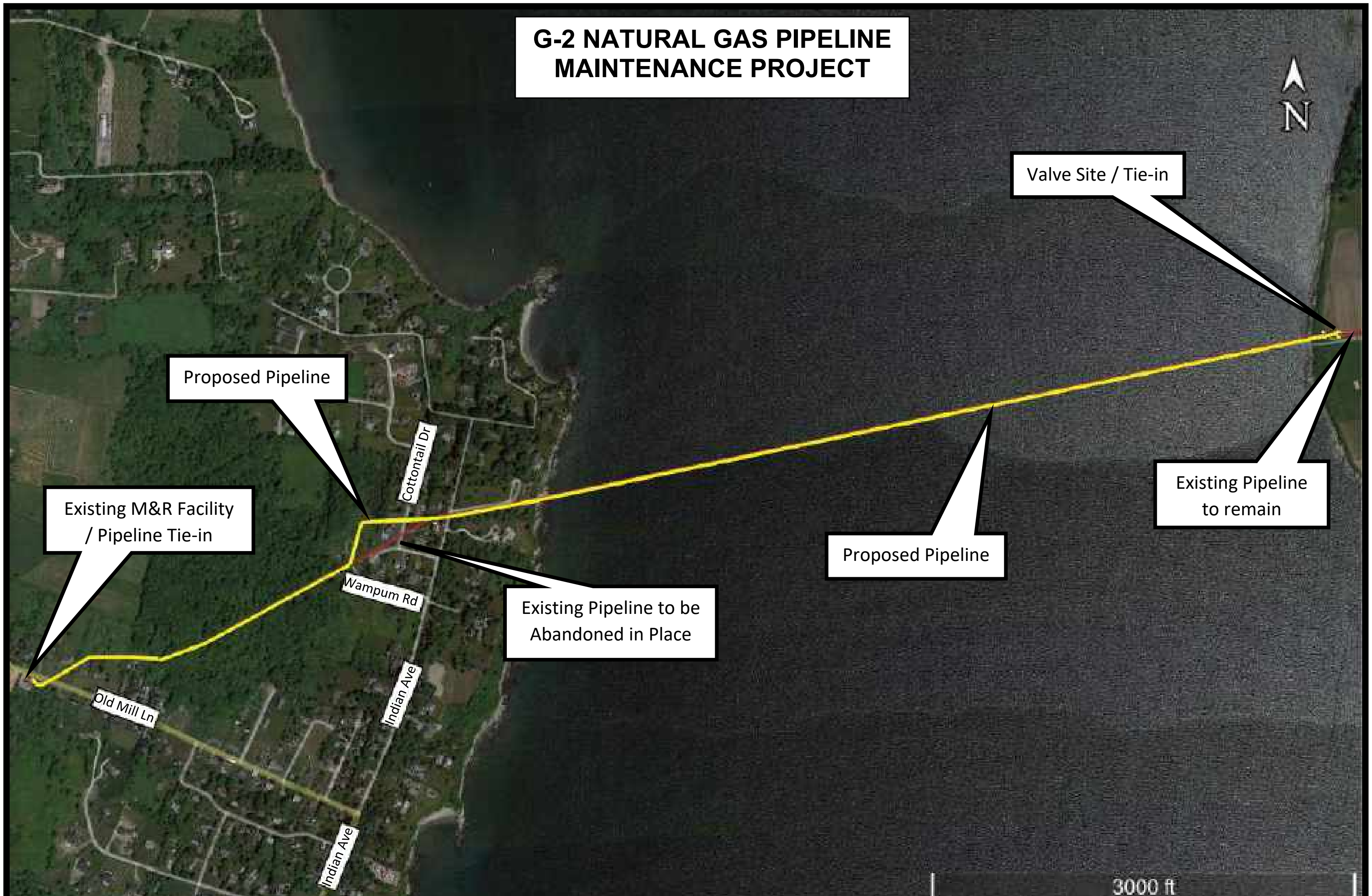
[1] Algonquin constructs, maintains, and operates interstate natural gas transmission pipelines under the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC") pursuant to the Natural Gas Act (15 U.S.C. §§ 717-717w). Algonquin's principal place of business is 915 North Eldridge Parkway, Suite 1000, Houston, Texas 77079.

be performed in a minimal amount of time with the goal of little to no inconvenience to you and your neighbors.

It is also our intent to communicate with you early and often about our Project in order to foster a constructive relationship throughout the Project lifecycle. If you have any questions or would like to discuss or obtain additional information concerning the Project please call our landowner hotline toll-free at 877-379-0338.

Very truly yours,

Nancy A. Kist
Senior Advisor, Lands & ROW
U.S. Projects



ENBRIDGE

Algonquin Gas Transmission, LLC
915 N Eldridge Pkwy, Houston, TX 77079

PROJECT OVERVIEW EXHIBIT

NEWPORT COUNTY
PORTSMOUTH AND LITTLE COMPTON, RI

DWG.: OVERVIEW EXHIBIT

SCALE: AS NOTED

REVISION: A

Middletown 2-5

Request:

Page 38 of the Supplemental Application states that the LNG operations at Naval Station Newport continued until 2010, "when the Company procured additional pipeline capacity from Algonquin."

a. Has the Company attempted to procure additional capacity from Algonquin since 2010? Have these attempts been successful?

b. How much additional capacity was procured from Algonquin in 2010?

c. How much additional capacity, if any, has been procured from Algonquin since 2010?

Response:

a. The Company successfully procured an additional 5,000 Dth/day of capacity from Algonquin Gas Transmission in 2022.

b. In 2010, the Company procured an additional 10,000 Dth/day of capacity from Algonquin Gas Transmission.

c. Please see response to part a., above.

Prepared by or under the supervision of: James M. Stephens

Middletown 2-6

Request:

On page 6, Witness Olney states the following: "Even in the alternatives in which the Project is discontinued in 2030, there are no additional GHG savings from avoided Project operation. Again, that is because the Project is not expected to be utilized in normal operation, because it is only utilized in the event of an upstream system disruption that would have otherwise caused system shutoffs."

a. Will LNG be stored at the facility during the winter mobilization season in anticipation of an event requiring the operation of the facility? If so, please indicate the volume of LNG stored at the facility and the duration of that storage. How much additional capacity was procured from Algonquin in 2010?

b. Does the Company assert that, in the event LNG is stored at the facility in anticipation of facility operation, no methane will be released from the facility's equipment? If so, please provide documentation or evidence supporting this assertion.

c. In the event that the facility is needed, and vaporization and injection operations occur, what is the estimated leakage rate of methane from the facility's equipment? How does this compare with leakage rates from permanent distribution system equipment such as the take station?

Response:

a. Yes, LNG will be stored at the facility during the winter mobilization season for the purpose of pipeline reliability and capacity reinforcement. Up to 84,000 gallons of LNG will be stored onsite for the December through March winter heating season. This increase in the current storage capacity is a result of the Company's plan to purchase advanced queen trailers outfitted with submerged high-pressure pumps, as noted in Section 3.2.2 of the Siting Report, that replace the requirement for a standalone high pressure pump trailer.

   Please see the Company's response to Middletown 2-5 for details on the additional capacity procured from Algonquin in 2010.

Prepared by or under the supervision of: Laeyeng Hunt and Brian Kirkwood

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a. No, some methane is manually released at the facility under the following conditions:

   - When the storage equipment is conducting initial cool down from ambient temperature to LNG storage temperatures, venting to atmosphere is required. During this cool down process, most of the boil-off gas ("BOG") is not able to be recovered in BOG recovery manifold due to pressure differences of the vessel being cooled down and the distribution pipeline pressure connected to the BOG manifold.

   - When transport trucks have completed offloading LNG, they are required to reduce trailer pressure before leaving the site. The BOG manifold's minimum pressure is greater than the minimum pressure requirement of the LNG transport trailers thus requiring venting to atmosphere.

   - After initial cool down has been completed, normal operations for unloading LNG transports do not require venting to atmosphere. In certain instances, however, it may be required to vent BOG to the atmosphere when capacity of the preferred BOG recovery manifold is exceeded. Factors that can increased BOG pressure are the LNG quality and temperature, the quality of the storage trailer insulation, atmospheric pressure, and the rate of LNG transfer between tanks.

   - When LNG trucking transfer is completed, a small amount of methane is released during the hose purge upon disconnection. It is not possible to recapture this small amount of released gas.

   - Finally, though it is extremely rare and has not occurred since the commissioning of the BOG manifold in 2021, extremely low atmospheric pressures can temporarily increase BOG rates greater than the BOG recovery manifold's capacity. If an extreme low atmospheric pressure condition occurred, the BOG recovery manifold would be used to its full extent; however, it is possible that further venting to atmosphere would be required.

   Out of normal operations at the facility, there have been no unintentional methane releases such as equipment leakage. Gas detection, both fixed and portable, is utilized while the site is in standby and in operation. Any abnormal operating conditions, including the unintentional release of methane, are required to be reported to management.

Prepared by or under the supervision of: Laeyeng Hunt and Brian Kirkwood

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c. There are no detectable leakage rates observed from the facility during vaporization and injection operations aside from the manual releases summarized in the response to part b., above. With respect to the requested comparison to "leakage rates from permanent distribution system equipment such as the take station," there are no detectable gas leaks at take stations. All take stations have fixed gas detection that calls out to gas control. In its most recent System Integrity Report,[1] the Company estimates that lost and unaccounted for gas accounts for 2.7 percent of the total of volume of gas delivered to, or injected into, the Company's distribution system in Rhode Island. This percentage includes losses from leaks, broken meters, releases during repairs, and theft.

[1] Please see the Company's Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan filing in Docket No. 22-54-NG at Bates page 136 available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-12/2254-RIE-Book1-2024FY-GasISR%2012-22-22.pdf.

Prepared by or under the supervision of: Laeyeng Hunt and Brian Kirkwood

RIEC4

CLF-1-6

Final Draft 12-14-2022

RHODE ISLAND 2022 CLIMATE UPDATE

RI EXECUTIVE CLIMATE CHANGE COORDINATING COUNCIL

AS APPROVED DECEMBER 15, 2022 BY THE RIEC4

Executive Summary

On April 14, 2021, Governor Dan McKee signed into law the *2021 Act on Climate*, which set mandatory, enforceable climate emissions reduction goals culminating in net-zero emissions by 2050. This legislation updated the previous 2014 Resilient Rhode Island Act, positioning the state to boldly address climate change and prepare for a global economy that will be shifting to adapt to clean technology.

The Act on Climate required that the Executive Climate Change Coordinating Council (RIEC4) deliver an update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022 (referred to as the '*2022 Update*').

After a fourteen-month process involving substantial stakeholder engagement, research, and compilation and coordination among the 13 state agencies in the RIEC4, this *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead.[1] We have reviewed the 2016 plan, reflected on the substantial work that has been done in Rhode Island over the past six years, and provided an interim path forward based on work being done across state government.

Looking back, in the 2016 Greenhouse Gas Reduction Plan the authors identified six key policy recommendations for moving forward in Rhode Island:

- Support further evaluation of the costs and benefits of GHG mitigation pathways, including macroeconomic, environmental, and health impact analyses.
- Develop a state-of-the-art 2018-2020 Three-Year Energy Efficiency Procurement Plan, with special focus on expanded access to delivered fuels (oil and propane) heating customers, opportunities to drive toward new demand response strategies, and expanded financing mechanisms to leverage capital toward the achievement of robust savings goals.
- Initiate an effort to escalate clean energy adoption in Rhode Island, elevating our state's position as an emerging leader in renewable energy and building off recent momentum from the nation's first offshore wind farm.
- Explore state and regional mechanisms for promoting clean transportation solutions consistent with addressing the state's largest GHG source sector.
- Craft a framework for addressing utility, rate, and regulatory modernization to position Rhode Island on the cutting-edge of power sector transformation activities and demonstrate our state as a proof-of-concept testbed for integrating clean energy, empowering customers, and improving the resiliency of our electric grid.
- Pursue regional approaches where they promise to enhance progress toward GHG goals, either through existing collaborations such as the Regional Greenhouse Gas Initiative (RGGI) or through newly emerging ones.

Rhode Island has remained focused in these areas and has followed through on all of them. These have been the guiding principles for much of the work done by the RIEC4 over the time since they were published. The specifics of each are outlined in detail in this *2022 Update*. Former RIEC4 Chairperson Janet Coit was clear, however, in her letter submitting that report in 2016 to the Governor and General Assembly that it was just a beginning, and much work and refinement had to follow if Rhode Island was to meet its emissions reduction goals.

[1] The 13 official member agencies of the RIEC4 can be found listed at https://climatechange.ri.gov/state-actions/ri-executive-climate-change-coordinating-council-ec4 In addition, representatives from the RI Department of Labor and Training (RIDLT) have been participating in the meetings (non-voting).

When the legislature passed the Act on Climate and it was signed by Governor McKee in April of 2021, the sense of urgency increased. Goals became enforceable mandates and clear priorities were set for equity, justice, and workforce development. These priorities were to be central to all our work on reducing emissions. Regular reporting, metrics, and dashboards, as well as strategic plans were required to ensure we stayed on track to meet our mandates and clearly communicate status and progress. The *2022 Update* is the first of the plans required by the Act on Climate.

Beginning in September 2021, the RIEC4 initiated a comprehensive public involvement strategy to provide transparency and opportunities for engagement on the development of the *2022 Update.* The RIEC4 met more often – bimonthly versus quarterly – and held meetings throughout the state to allow more Rhode Islanders to participate in critical conversations about climate change. The RIEC4 held over 20 public listening sessions and workshops to gather public input for the *2022 Update*. The RIEC4 has worked closely with Governor McKee to make key appointments to both the RIEC4 Advisory Board and the Science and Technical Advisory Board, has begun work to create a Climate Justice Advisory Group, and OER and DEM have both onboarded additional staff to assist with the state's numerous climate programs, including staff members in both organizations focused on energy and climate justice.

Much has changed in the world, the country, the region, and Rhode Island with respect to attitudes, actions, and science related to climate change since 2016. Key changes since 2016 include new emissions reduction mandates directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

Perhaps most importantly, the *2022 Update* builds the foundation for developing the *2025 Climate Strategy*. The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate, in hope these priorities will be well established by 2025. The *2025 Climate Strategy* will then build out workplans for each sector to meet our mandates and set us on a viable path to reach net-zero emissions by 2050.

The development of the *2022 Update* was an opportunity to reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources. Updates of the modeling will be a significant component of the 2025 Climate Strategy.

The 2021 Act on Climate set forth a mandate to reach 'net-zero emissions by 2050'. However, the law did not define the terms 'net-zero' or 'emissions', leaving open questions of which emissions, how we net those emissions, and on what timeframe the netting occurs. Following public discussions held in three sharing sessions and supplemented by online comments, the *2022 Update* provides definitions and offers several critical caveats related to how our definitions may evolve over the next three decades.

During the dialogs with stakeholders, it became clear that the development of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* was also an opportunity to reconsider and confirm technical aspects of modeling. Current emissions inventory processes, methodologies, and tools were reviewed in detail and, in many cases updated and modernized to use better local data. Two central principles governing how and when we update process, methodologies, and tools specifically related to the 1990 baseline and estimating emissions from the land use, land use change, and forestry (LULUCF) sector. We also include explicit actionable recommendations for additional analysis in support of the development of the *2025 Climate Strategy*, as well as recommendations for improving transparency of how Rhode Island will assess interim compliance with the 2021 Act on Climate.

In terms of progress and where we stand, Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Rhode Island's Greenhouse Gas Emissions come from several sources. The transportation sector is the largest source (39.7%) of greenhouse gas emissions. The thermal sector (residential heating, commercial heating, industry, and natural gas distribution) accounts for 38.8% of emissions. The electricity consumption sector accounts for 18.9% of emissions. Agriculture and waste account for the other 2.6% of emissions. As we electrify more and more of our transportation and heating systems, those emissions will switch to the electricity consumption sector, which will then be eliminated by transition to renewable, zero-emission sources of electricity.

As of July 2022, the state has counted approximately 1,149 MW of clean energy generation capacity. Of Rhode Island's current 1,149 MW total, 430 MW is offshore wind which is mostly under contract for the Revolution Wind facility scheduled to come online in 2026, 527 MW is solar, 148 MW is onshore wind, 35 MW is landfill gas/anaerobic digestion, and 9 MW is small hydroelectric power. Including the 400 MW Revolution Wind project, approximately 85 percent of Rhode Island's current clean energy portfolio is comprised of in-state renewables or projects scheduled for adjacent federal waters.

Key Studies and Legislation Since 2016

Since 2016, the State has conducted several in-depth studies deepening our understanding of decarbonization activities and enabling actions. The *2022 Update* includes a list and summary of over a dozen major studies that either were directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning.

The list of studies in the *2022 Update* is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy. This list does not include state plans in which stakeholders and agencies prioritize and plan investments in state infrastructure nor does this list include retrospective evaluations of programs, though such evaluations are crucial to increasing the impacts of these programs. This list also omits studies conducted by federal agencies and non-governmental organizations that add to our understanding and depth of knowledge.

However, all these studies have advanced the specific knowledge of both decarbonization and resilience in Rhode Island.

Additionally, the Rhode Island General Assembly has debated and passed several bills addressing different aspects of our response to climate change. Probably the most significant legislation was the 2021 Act on Climate, which set statewide, economy-wide climate goals that are both mandatory and enforceable. The Act requires the state reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and reach net-zero emissions by 2050. The Act also requires the development of this update to the *2016 Greenhouse Gas Emissions Reduction Plan* in 2022 and a comprehensive climate strategy by 2025, to be updated every five years thereafter.

Critically, the Act deems addressing the impacts on climate change to be within the powers, duties, and obligations of all state departments, agencies, commissions, councils, and instrumentalities, including quasi-public agencies. The Act gives each agency the authority to promulgate rules and regulations necessary to meet the Act's greenhouse gas emissions reduction mandates.

Also in 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil. The new law that was signed by

Governor McKee requires home heating oil to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025 and 50% in 2030.

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2022, the RI legislature passed a bill, subsequently signed by Governor McKee, to commit the state to 100% renewable energy by 2033.

Offshore wind-powered energy will play a major role in the reduction of greenhouse gasses. In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. In 2022, the legislature authorized procurement of up to an additional 1000 MW of power generated from offshore wind.

Obviously, action is needed to meet the upcoming emissions reduction mandates in the Act on Climate. While the details, modeling, and balancing of these actions across the sectors of our economy will be done as part of the *2025 Climate Strategy*, the following actions are underway and must continue.

Turning our attention to priority actions in Rhode Island's three biggest source sectors – electric, transportation and thermal – this report identifies strategic actions the state needs to advance to meet mandates as outlined in the Act on Climate. Additional priority actions for land use and climate justice are identified further in the report.

Priority Actions for the Electric Sector

Implement the 100% Renewable Energy Standard

During the 2022 legislative session, a 100% Renewable Energy Standard (RES) was passed by the RI General Assembly and signed by Governor McKee. The RES ensures we decarbonize the electric sector with yearly targets. Rhode Island's RES is an existing statutory mechanism by which we can require electricity suppliers to meet an increasing percentage of retail electric sales from renewable energy resources. The RES also sets forth an accounting methodology and process to ensure compliance.

The schedule and yearly targets set forth in the 100% RES law steadily increase over time starting with an additional four percent of retail electricity sales in 2023 and increases until an additional 9.5% of retail electricity sales are needed in years 2032 and 2033.

Modernize the Electric Grid

Our current electric grid is built for one-way flow of electricity from a few large power generators to many end customers. However, decarbonizing our electric grid necessitates a paradigm of two-way power flow between renewable energy systems of all sizes distributed throughout the electric grid to all customers. Safely, reliable, and affordably building out the electric grid will require electric distribution companies to make strategic investments in technologies for a twenty-first century electric grid.

Grid modernization technologies serve the purpose of managing power flow, protecting workers and customers, improving visibility into electricity consumption and grid conditions, building resilience from power outages, and giving customers more choice and control over their electricity use.

Deploy Advanced Meters

Meters that measure electric (and gas) consumption for utility accounts range in capability from simple counting and aggregation of energy use over a billing period to detailed accounting of consumption throughout minutes-long intervals and real-time communication with customers. Most meters in Rhode

Island are more like the former – basic devices that report how much energy a customer uses over the course of a month – and they are reaching the ends of their useful and reliable lives.

Procure Offshore Wind

Offshore wind is a not only a vital renewable energy resource but a significant economic driver of growth and jobs in Rhode Island. As we move to implement the 100% Renewable Energy Standard, offshore wind will play a critical role in affordable meeting both our in-state renewable energy requirements as well as supporting the region.

On July 6, 2022, Governor McKee signed a bill into law adding up to 1,000 MW more megawatts of offshore wind to Rhode Island's clean energy portfolio. Rhode Island Energy, RI's new gas and electric utility as of 2022, then released a request for proposals for up to 1,000MW in the Fall of 2022 (proposals are due in March 2023). It is expected that any new offshore wind projects procured through the RFP would be operational during the first half of the 2030s.

Continue Energy Efficiency Work

Energy efficiency programming in Rhode Island helps residents and businesses adopt and install technologies that allow them to receive the same or better performance from their equipment, buildings, and appliances while using less energy to do so. Rhode Island's energy efficiency programs are offered through the state's utilities and from the Rhode Island Office of Energy Resources. These services can directly lower energy bills for participating consumers, reducing both emissions and energy costs for all consumers, which help support the local economy, and combat climate change. In 2021 Rhode Island's least cost procurement statute was extended to 2029, which ensures these energy efficiency programs for the next seven years.[2]

Complete RGGI Program Review and Implement Suggested Changes

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the power sector. It represents the first cap-and-invest regional initiative implemented in the United States. Rhode Island has continued to be an active participant in RGGI since 2009. A Third Program Review is currently underway throughout 2021-2023, which will inform RGGI program design for future years.

Priority Actions for the Transportation Sector

There are two ways to reduce emissions in the transportation sector: consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions and take action to incentivize lower-emissions mobility.

Target 10% Penetration of Electric Vehicles by 2030

As of October 2022, Rhode Island has 6,275 *registered* electric vehicles, which is a 1,313% increase in EVs since 2015. If Rhode Island adopted Advanced Clean Cars II, 68% of all new passenger vehicles *sold* in the state would be electric in 2030. By having programs focused on Zero-Emission Vehicles, such as

[2] Least Cost Procurement: http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM

DRIVE EV, an electric vehicle rebate program available to Rhode Island residents and businesses, it will help increase the amount of registered electric vehicles on the road in Rhode Island as well as paving the way for further expansion of EV penetration, post 2030.

As Resources are Available, look to the Transit Master Plan (TMP) and Bicycle Mobility Plan (BMP) as Well-vetted Strategies for Next Steps

RIDOT, RIPTA, and RIDSP have all developed planning work tasks to support mapping, evaluation, and implementation of projects and priority corridors which were recommended in the TMP or BMP respectively. These agencies continue to prioritize projects advancing better connections for both transit and bicycle/pedestrian modes as the state looks to identify funding for the TMP and BMP.

Reduce RIPTA's Carbon Footprint by Decarbonizing Rhode Island's Transit Fleet

The full cost of fleet decarbonization is currently unknown. RIPTA is preparing an Action Plan for Electrification and Service Growth which will provide estimated annual decarbonization infrastructure, vehicle, and energy costs. This plan will be complete in 2023.

Adopt Advanced Clean Trucks Rule

The federal Clean Air Act (CAA) grants the U.S. Environmental Protection Agency (EPA) original jurisdiction for establishing emission standards for new motor vehicles, including heavy-duty trucks.

Under CAA Section 177 (42 USC § 7507), states that choose to adopt vehicle emission standards that are more stringent than the federal standards for new vehicles may adopt standards that are identical to any standards adopted by California.

Rhode Island has previously adopted California's emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California's standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles. Rhode Island should continue to adopt new rules, including California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers, as well as the Advanced Clean Cars II regulation.

Incentivize Electric Mobility

In July 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) and e-Bike rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program. It works towards making EVs more affordable for more Rhode Islanders.

Model Climate Impacts of Transportation Demand

To understand how projects of regional significance in the State Transportation Improvement Program (STIP) contribute to GHG emissions and to assess future policy options and investment strategies towards the reduction of those emissions, Rhode Island Department of Transportation (RIDOT) is working with other state partners to improve the modeling of GHG, establishing performance measures to help reduce emissions and creating a Carbon Reduction Plan per federal guidelines.

Investments in transportation capital projects are prioritized based on many factors, including asset management, readiness, risk levels, available funding, and opportunities for partnership. Due to changes in both state and federal regulations and guidelines, this data-driven process now will include another layer that determines how regionally significant projects impact carbon emissions in the state. The state planning process determines these priorities so that adequate investments are made based on the proper funding sources and uses, and to meet mandates such as performance measures.

Develop 'Complete Streets' State Plan Leveraging Federal Funding

The USDOT defines "Complete Streets" as "Streets that are streets designed and operated to enable safe use and support mobility for all users. Those include people of all ages and abilities, regardless of whether they are travelling as drivers, pedestrians, bicyclists, or public transportation riders. The concept of Complete Streets encompasses many approaches to planning, designing, and operating roadways and rights of way with all users in mind to make the transportation network safer and more efficient. Complete Street policies are set at the state, regional, and local levels and are frequently supported by roadway design guidelines."

In Rhode Island, RIDOT and RIDSP have joined together to maximize the impact of that funding. RIDSP will lead a 2.5-year effort to invest more than $250,000 in combined planning funds into development of a Complete Streets Plan and Design Guidelines. This project has kicked off (fall 2022) with a draft RFP for consultant assistance, which RIDSP expects to complete and issue in spring 2023, in coordination with RIDOT and RIPTA. This project is included in the FY2023 Unified Planning Work Program (UPWP), which is the annual RIDSP program of projects under development.

Priority Actions for the Thermal Sector

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island.

Continue Energy Efficiency Programs and Weatherization

Weatherization of buildings is key to ensuring a successful transition to decarbonized heating and cooling, because it helps to decrease our overall energy demand. While the utilities' efficiency programs support a number of weatherization programs and appliance efficiency standards, these should continue to be expanded

Target 15% Penetration of Energy Efficient Electric Heating by 2030

A conversion of 15% of Rhode Island's buildings from fossil fuel heat to efficient electric heating by 2030 is an aggressive, but attainable and necessary target. While the market for efficient electric heating – including a variety of heat pump technologies – is relatively nascent in Rhode Island, the next several years will be used to build a strong foundation for the market to expand at a quicker pace in the last two decades as we approach 2050. The priority actions below will help us reach this 15% target and plan for further expansion, in tandem with other decarbonized thermal technologies, post 2030.

Efficient Heat Pump Incentives

There are several mechanisms for incentivizing efficient heat pumps that are expected to be used in the coming years. First, the Office of Energy Resources will be launching the High Efficiency Heat Pump Program (HHPP) in 2023, which will combine federal funding from the American Rescue Plan Act (ARPA) with existing incentives provided by Rhode Island Energy's energy efficiency programs. Second, the Inflation Reduction Act, recently passed by the U.S. Congress, will provide a suite of incentives including tax credits and rebate programs for heat pumps and other electric thermal appliances, such as induction stoves. The State will work diligently to ensure that the maximum benefits are easily accessible to Rhode Islanders and that federal incentives for heat pumps compliment State offerings.

Increase Biofuel Blending in Accordance with the 2021 Biofuel Heating Oil Act

The 2021 Biofuel Heating Oil Act requires that, by 2030, all No. 2 distillate heating oil sold in Rhode Island, "shall at a minimum meet the standards for B50 biodiesel blend and/or renewable hydrocarbon diesel." This means that by 2050 all heating oil in the state will contain at least 50% biodiesel, significantly decreasing the carbon intensity of home heating oil.

Continue to Abandon Leak-Prone Gas Pipes and Pursue Non-pipe Alternatives

Public Utilities Commission Docket No. 5210, "National Grid's FY 2023 Gas Infrastructure, Safety and Reliability (ISR) Plan," contains the Leak Prone Pipe Replacement Program which replaces leak-prone gas mains throughout the Rhode Island gas distribution network. Since the program's beginning in 2012, 537 miles of leak-prone pipe have been replaced and an additional 951 miles are expected to be completed by the program's end in 2035. Gas mains that are replaced through this program have an expected lifespan between 50-100 years, locking in gas infrastructure well beyond the target date for an emissions-free state. Therefore, in the coming years, more emphasis should be placed on non-pipes alternatives (NPA). NPA seeks alternative ways of providing thermal service to Rhode Islanders, rather than expanding and enforcing the fossil gas network.

Future of the Gas Distribution System

Just over half of Rhode Islanders are connected to the gas system for heating, cooking, and various other household appliances. Gas is also used for high-heat industrial processes. Pipelines and other gas infrastructure have been, and continue to be, built with decades to centuries-long time horizons.

In August 2022 the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG, "Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate." Commencing in 2023, this docket will serve as an important first step in beginning to plan for the gas system's transition to carbon neutrality.

Begin Developing a Renewable Thermal Standard

Like the recently enacted 100% Renewable Energy Standard, the state should begin to plan for a renewable thermal standard to phase thermal emissions down at intervals that align with the Act on Climate emissions reduction mandates.

Looking Forward to 2025 and Beyond

The Act on Climate required that the RI Executive Climate Change Coordinating Council (RIEC4) deliver this update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022. After a fourteen-month process involving substantial stakeholder engagement, research, and compilation and coordination among the 13 state agencies in the RIEC4, this *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead.

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with RMI and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by Acadia Center utilizing RMI's *Energy Policy Simulator* (EPS). By modeling a short list of key policy scenarios as outlined in the report, it is projected that Rhode Island is not fully on track to meet the Act on Climate's 2030 reduction mandate of 45% by 0.5 $MMTCO_2e$. To put this in perspective, the emissions in

2030 are projected by the EPS to be 7.39 $MMTCO_2e$, as compared to the 1990 baseline of 12.48 $MMTCO_2e$. This is a very simple, preliminary model that verifies Rhode Island is moving in the right direction but is not at the point where we can be confident in our success. More refined modeling and development of specific strategies to increase that confidence will be the crux of the *2025 Climate Strategy.*

On that note, the RIEC4 will immediately turn attention to the *2025 Climate Strategy*, which will include a set of "strategies, programs, and actions to meet economy-wide enforceable mandates for greenhouse gas emissions" due by December 31, 2025. The *2025 Climate Strategy* will be developed via a robust stakeholder process modeled closely on the process used for the *2022 Update* and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The *2025 Climate Strategy* will be a comprehensive working document that will be updated every five years thereafter.

The agencies in the RIEC4 will focus on implementation of the action items outlined above and throughout this report. The RIEC4 will continue to work with the Advisory Board, as well as the Science and Technical Advisory Board (STAB) and Climate Justice working group, to refine policies and develop metrics and the public dashboard called for in the Act. The metrics and dashboard will serve as an educational and communications tool to highlight progress and the status of our efforts.

Discussions of identifying and allocating resources to these efforts will continue. The decarbonization and transition of our economy must be done carefully, and deliberately, to meet the goals set forth in the statutes. This will require both internal and external expertise and support for all the agencies. In the near term, prospects for federal support in many areas looks strong, particularly from the federal Bi-Partisan Infrastructure Law and the Inflation Reduction Act. However, these federal funds will not provide complete support needed for our efforts and state funds will be needed. Effective community and stakeholder engagement will especially require financial and expert support so that the voices of all Rhode Islanders can be heard as we move forward.

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Introduction and Scope

On April 14, 2021, Governor Dan McKee signed into law the 2021 Act on Climate, which set mandatory, enforceable climate emissions reduction goals culminating in net-zero emissions by 2050. This legislation updated the previous 2014 Resilient Rhode Island Act, positioning the state to boldly address climate change and prepare for a global economy that will be shifting to adapt to clean technology.

The Act on Climate required that the Executive Climate Change Coordinating Council (RIEC4) deliver an update to the *2016 Greenhouse Gas Emissions Reduction Plan* to the Governor and General Assembly by December 31, 2022 (referred to as the '*2022 Update*'). The Act was clear that the *2022 Update* needed to be informed by public comment and stakeholder discussions. This *2022 Update* reflects the work of many people over the past fourteen months and is the first major milestone in implementing the Act on Climate.

Following the completion and submission of this report, our attention will turn to the strategies, actions, and modeling to meet the reduction targets in the law. The RIEC4 will develop a plan to incrementally reduce climate emissions to net-zero by 2050 to be delivered to the Governor and the General Assembly by December 31, 2025 (referred to as the '*2025 Climate Strategy*'). The *2025 Climate Strategy* will be developed via a robust stakeholder process and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The *2025 Climate Strategy* will be a comprehensive working document that will be updated every five years thereafter. This, however, should not be viewed as the only opportunities or requirements for state agencies and offices pertaining to climate action (e.g. regulatory authority, mission, duties, etc. as called for in RIGL §42-6.2-8).

A note on terminology:

- ***2016 Plan*** refers to the *2016 Greenhouse Gas Emissions Reduction Plan* published in December 2016 in response to the 2014 Resilient Rhode Island Act
- ***2022 Update*** refers to the required update to the *2016 Greenhouse Gas Emissions Reduction Plan*, as mandated by the 2021 Act on Climate
- ***2025 Climate Strategy*** refers to the set of "strategies, programs, and actions to meet economy-wide enforceable targets for greenhouse gas emissions" due "no later than December 31, 2025, and every five (5) years thereafter", as mandated by the 2021 Act on Climate

The following scope and objectives of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* were informed by discussions with stakeholders and the public during a November 2021 sharing session, as well as by comments received through the online public comment portal.[3]

The *2022 Update* should:

- *Be responsive to the 2021 Act on Climate*
- *Center equity and be developed using a meaningful public participation process*
- *Leverage lessons learned since 2016*
- *Build a foundation for the* 2025 *Climate Strategy*
- *Reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources*
- *Focus on near-term actions to achieve the 2021 Act on Climate's 2030 mandate*

[3] The RIEC4 utilized an online comment portal called Smart Comment to collect and review comments submitted by interested parties.

First, the *2022 Update* must first and foremost be responsive to the 2021 Act on Climate. We are operating under the premise that the legislative intent and objective of the 2021 Act on Climate mandates is to limit the worst impacts of climate change in alignment with the latest science.[4] We rely on the latest science and recommendations of the Intergovernmental Panel on Climate Change (IPCC).[5]

Second, developing the *2022 Update* should rely on robust and meaningful stakeholder engagement in order to appropriately center equity into the discussion. We welcomed feedback and suggestions from stakeholders throughout the development process, and relied on a combination of workshops, sharing sessions, and one-on-one conversations to strike a helpful balance of providing support, facilitating conversation, and making space to listen and learn.

Third, the *2022 Update* should recognize and leverage lessons learned since 2016 when the previous greenhouse gas emissions reduction plan was published. Key changes since 2016 include new emissions reduction targets directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

Fourth, the *2022 Update* should build a foundation for developing the *2025 Climate Strategy*. These two documents should avoid duplicating each other and instead build on each other so that we place continued pressure on reducing our emissions. The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate. The *2025 Climate Strategy* will then build out workplans for each major sector in order to meet our interim mandates and set us on a viable path to reach net-zero emissions by 2050.

Fifth, the development of the *2022 Update* is a ripe opportunity to reconsider and confirm technical aspects of modeling, be action oriented, promote resilience and reliability, and emphasize the role of renewable energy resources. Modeling will be a significant component of the 2025 Climate Strategy.

Finally, the *2022 Update* identifies a clear set of priority near-term action items that will keep Rhode Island on a compelling path to reach the 2021 Act on Climate's 2030 mandate of 45% emissions reduction below our 1990 baseline. Further accountability, roles, and responsibility are included for each priority action wherever possible.

Based on these objectives, we developed the following scope of the *2022 Update*, which informed both our workplan for developing the *2022 Update* and the outline reflected in this document.

Scope of the *2022 Update:*

- Technical updates:
  - Update greenhouse gas emissions reduction targets to comply with the 2021 Act on Climate, and define the goal of reaching 'net zero emissions by 2050'
  - Review modeling to ensure the 1990 baseline is sound, data are defensible, and modeling assumptions are reasonable

[4] See for example RIGL §42-6.2-3.9, which states state agencies shall "Develop plans, policies, and solutions based on the latest science to ensure the state continues to have a vibrant coastal economy, including protection of critical infrastructure, and a vibrant and resilient food system that can provide affordable access to healthy food for all Rhode Islanders" (emphasis added).

[5] Intergovernmental Panel on Climate Change

- Update pathways, policy, and implementation strategies:
  - Restructure pathways and policies from *2016 Plan* to coordinate with emissions sectors
  - Provide updates on progress for each policy and implementation strategy recommended in the *2016 Plan*
  - Add policy and implementation strategies recommended by more recent studies
  - Refine policy and implementation strategies based on lessons learned
  - Update policy and implementation strategies to identify priority actions to meet the 2030 mandate, clarify roles, and identify mechanisms for accountability
  - Consider new and forthcoming funding opportunities
- Review and update the entire *2016 Plan* with equity appropriately centered and integrated throughout
- Identify key stakeholders to engage (and engage them!)
- Design a climate dashboard that tracks progress on community-prioritized outcomes using clearly defined, transparent, and meaningful metrics
- Identify and address the prerequisite needs of the *2025 Climate Strategy* and preview the work ahead

Components of the *2016 Plan* that do not need to be updated include the model itself; the guiding objectives to build on state success, enable markets and communities, and leverage regional collaboration; and the process of RIDEM's triennial greenhouse gas reporting.

Defining Net-Zero Emissions by 2050

The 2021 Act on Climate sets forth a mandate to reach 'net-zero emissions by 2050' (RIGL 46-6.2). However, the law does not define the terms 'net-zero' or 'emissions', and therefore leaves open questions of which emissions, how we net those emissions, and on what timeframe the netting occurs. Following public discussions held in three sharing sessions and supplemented by online comments, we propose the following definitions and offer several critical caveats related to how our definitions may evolve over the next three decades.

> 'Emissions' refer collectively to the set of greenhouse gases that contribute to climate change. Based on current science, greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. The greenhouse gases included in our definition of emissions may evolve over time if climate science uncovers additional gases contributing to climate change.
>
> 'Net-Zero' refers to the requirement that the summary measure of greenhouse gas emissions emitted over the course of a calendar year less the summary measure of greenhouse gas emissions absorbed or otherwise broken down over the course of a calendar year equals zero. All emissions can be summarized in a measure such as million metric tons carbon dioxide equivalent ($MMTCO_2e$) using global warming potential factors which adhere to international standards, including those of the IPCC[6] and UNFCCC[7], and are embedded within the US EPA's[8] greenhouse gas emissions inventory tools.

Which emissions?

Greenhouse gases are molecules that cause and exacerbate climate change. The IPCC and US EPA identify four types of greenhouse gases[9]:

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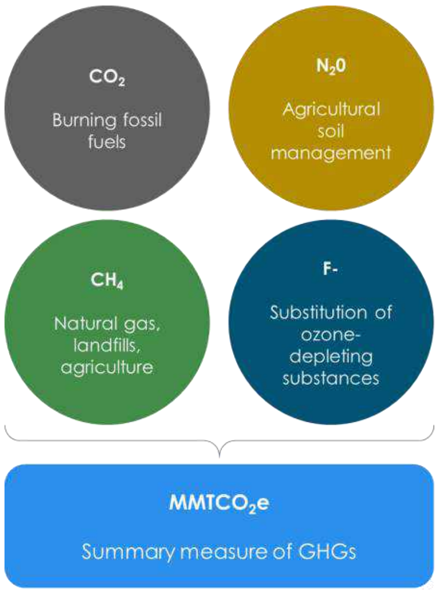
[6] Intergovernmental Panel on Climate Change
[7] United Nations Framework Convention on Climate Change
[8] United States Environmental Protection Agency
[9] "Greenhouse gases (GHGs) - Gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of radiation emitted by the Earth's surface, by the atmosphere itself, and by clouds. This property causes the greenhouse effect. Water vapour (H2O), carbon dioxide (CO2), nitrous oxide (N2O), methane (CH4) and ozone (O3) are the primary GHGs in the Earth's atmosphere. Human-made GHGs include sulphur hexafluoride (SF6), hydrofluorocarbons (HFCs), chlorofluorocarbons (CFCs) and perfluorocarbons (PFCs); several of these are also O3-depleting (and are regulated under the Montreal Protocol). See also Well-mixed greenhouse gas" [IPCC Glossary] Note that IPCC, US EPA, and Rhode Island do not count water vapor or ozone in tracked emissions.



Carbon dioxide (CO2) is the most prevalent greenhouse gas. Its primary source is from the combustion of fossil fuels.

Nitrous Oxide (N2O) is a type of greenhouse gas that is emitted in part from certain agricultural soil management practices.

Methane (CH4) is released into the atmosphere from natural gas leakage, from landfills, and from some agriculture.

Fluorinated gases are a set of greenhouse gases containing hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3). While these gases are less common, they have a more substantial impact on climate change. These gases primarily stem from the substitution of ozone-depleting substances.

One legislative objective of the 2021 Act on Climate is to limit the worst impacts of climate change in alignment with the latest science.[10] We rely on the latest science and recommendations of the IPCC. Since all four types of greenhouse gases are recognized by the IPCC as contributors to climate change, all four must be included in our accounting of emissions generally and in our emissions reduction strategies specifically. If additional greenhouse gases are identified, then those greenhouse gases should also be accounted for.

> 'Emissions' refer collectively to the set of greenhouse gases that contribute to climate change. Based on current science, greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. The greenhouse gases included in our definition of emissions may evolve over time if climate science uncovers additional gases contributing to climate change.

The IPCC regularly re-evaluates the relative contributions of these greenhouse gases to climate change. One key parameter used to describe these relative impacts is a greenhouse gas's 'global warming potential' (GWP). The GWP allows for comparisons of the global warming impact of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2). All global warming potentials are relative to the impact of carbon dioxide, whose GWP is equal to one (GWP = 1). The greater the GWP, the more a given gas warms the Earth compared to CO_2 over that time period. Other greenhouse gases, which have relatively more impact on causing climate change on a molecule-by-molecule basis, have global warming potentials greater than one.

Global warming potentials depend on both the impact of each molecule of the greenhouse gas and how long each molecule stays in the atmosphere. Greenhouse gases that tend to stay in the atmosphere longer have a longer timeframe over which they can cause climate change; on the other hand, molecules that are broken down or absorbed quickly have only a short time over which they can contribute to climate

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[10] RIGL §42-6.2-3.9 states state agencies shall "Develop plans, policies, and solutions based on the latest science to ensure the state continues to have a vibrant coastal economy, including protection of critical infrastructure, and a vibrant and resilient food system that can provide affordable access to healthy food for all Rhode Islanders" (emphasis added).

change. Global warming potentials are continually studied by the IPCC and are subject to change over time depending on the most recent analyses.

In practice, we propose to use the global warming potentials embedded in the US EPA's greenhouse gas emissions inventory tools, which adhere to international standards, including the IPCC and UNFCCC. We additionally propose to include a qualitative or sensitivity analysis to describe how our current emissions levels may differentially contribute to climate change if global warming potentials are modified. For example, while our current inventory uses a 100-year timeframe for the global warming potential of methane (because this is the parameter embedded in the US EPA greenhouse gas inventory tool), we will also describe how our inventory might look different if we were to use a 20-year timeframe instead. A qualitative description may be included more frequently than an administratively intensive quantitative sensitivity analysis.

All emissions will be summarized in a metric called million metric tons carbon dioxide equivalent ($MMTCO_2e$). This metric accounts for both the amount of each greenhouse gas in our atmosphere *and* its relative impact on climate change. This is a common metric used across the climate science sector to summarize greenhouse gases.

Anthropogenic versus biogenic emissions sources

> *Biogenic emissions are emissions that come from natural sources.[11] In contrast, anthropogenic emissions are emissions that come from human activities.[12] Both types of emissions contribute to climate change, and both are accounted for in some manner by the US EPA's greenhouse gas inventory tools. However, our greenhouse gas inventory and emissions reduction strategies tend to focus more on anthropogenic emissions because these are the emissions within our control. We propose to include in our greenhouse gas inventory and definition of emissions whatever emissions sources – anthropogenic and/or biogenic – are recommended by the US EPA in alignment with IPCC guidance.*

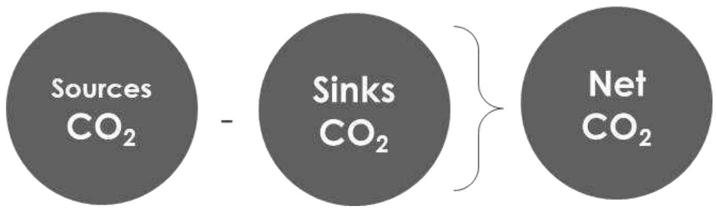
There are a variety of methods that can be used to estimate the greenhouse gas emissions from the electric sector. Our current accounting method for the electric sector is consumption-based, rather than generation-based.[13] This means that we calculate emissions based on electricity used within Rhode Island, regardless of where the generation sources are located that provide the electricity.

The consumption-based approach reflects significant historical and ongoing change in the mix of fuels used to generate electricity in New England. When we consider consumption-based versus generation-based inventories, we have to consider how we can ensure that all emissions are accounted for by some state. Consider, for example, Rhode Island and Maine. Rhode Island's consumption-based inventory only accounts for emissions from an in-state fossil-based power plant if its output electricity is consumed in state. However, let's say Maine only has a production-based inventory but uses some of the electricity from the Rhode Island power plant. In this fictional example, the emissions produced in Rhode Island and

[11] US EPA
[12] IPCC Glossary
[13] In May 2016, the EC4 voted to officially adopt a consumption-based methodology; this memo summarizes those considerations.

consumed in Maine would incorrectly not be accounted for in either state's greenhouse gas emissions inventory. This would lead to too little climate mitigation action.

Therefore, it is critical that we work with neighboring states and states in our region to understand the flow of emissions and ensure emissions are accounted for. This comprehensive accounting also requires consistency in how inventorying is done across state borders. In the absence of consistent methodology, we will need to caveat our greenhouse gas inventory with an additional description of which emissions may not be included.



How do we 'net' these emissions?

Netting is the process of accounting for both sources of emissions and 'sinks' that cause emissions to be absorbed, broken down, or otherwise rendered incapable of contributing to climate change. For example, tree growth is considered a carbon sink because trees absorb carbon from the atmosphere. There are two methods by which we can net emissions. Rhode Island's current greenhouse gas inventory first summarizes all greenhouse gas emissions sources as $MMTCO_2e$ and then subtracts all greenhouse gas emissions sinks as $MMTCO_2e$.[14] An alternative method is to require that each specific greenhouse gas reaches net zero. For example, the total methane emitted by all sources minus the total methane absorbed by all sinks is required to equal zero in 2050, as is required for each type of greenhouse gas.

Given the legislative objective of the 2021 Act on Climate to align Rhode Island's greenhouse gas emissions with the latest science and recommendations to limit global warming and resulting climate change impacts, we propose continuing our current method of netting emissions because the summary measure of $MMTCO_2e$ already encapsulates the total impact of emissions on climate change. In other words, netting each type of greenhouse gas provides no incremental aid in reaching our objective to limit climate change impacts, and may actually be more difficult to achieve.

> 'Net-Zero' refers to the requirement that the summary measure of greenhouse gas emissions emitted over the course of a calendar year less the summary measure of greenhouse gas emissions absorbed or otherwise broken down over the course of a calendar year equal zero. All emissions can be summarized in a measure such as million metric tons carbon dioxide equivalent ($MMTCO_2e$) using global warming potential factors which adhere to international standards, including the IPCC and UNFCCC, and are embedded within the US EPA's greenhouse gas emissions inventory tools.

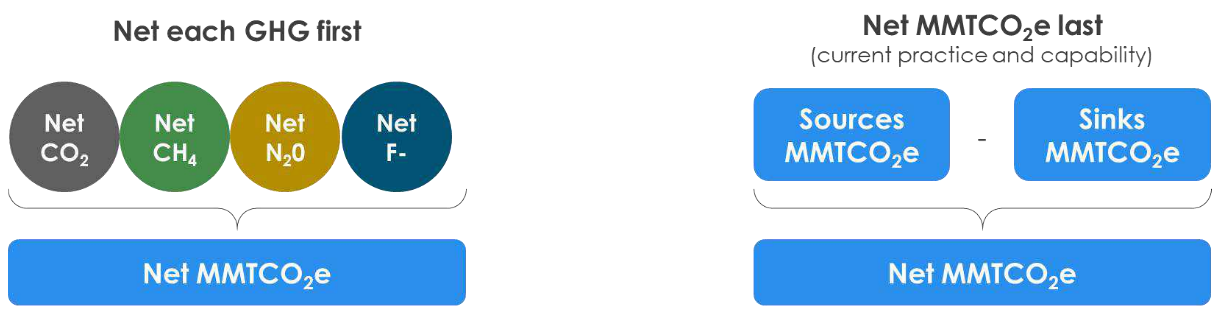
Rhode Island's current greenhouse gas emissions inventory methodology was updated for the 2019 inventory to account for emissions sinks. While the US EPA's greenhouse gas inventory tools do estimate emissions reductions from land use, land use change, and forestry (abbreviated LULUCF), these tools have known reliability issues and therefore are not included in previous years inventories. Rhode Island is

[14] We refer interested readers to the most recent Greenhouse Gas Emissions Inventory (2019) for more information about the updated methodology for accounting for LULUCF. https://dem.ri.gov/environmental-protection-bureau/air-resources/greenhouse-gas-emissions-inventory

moving ahead with utilizing state specific data to account for emissions reductions from LULUCF for 2019 and beyond.

- As we progress toward 2050, we will continue to refine methods of accounting for emissions reductions due to land use, land use change, and forestry.

If future policy objectives arise, such that reaching net-zero for a particular type of greenhouse gas is a solution, then we should revisit our method of netting emissions. We may also consider estimating net emissions for each type of greenhouse gas if our capability evolves such that doing so is not too burdensome; doing so may provide additional insight about the efficacy of our emissions reduction strategies.



Another consideration is whether to net emissions economy-wide or require each sector within the economy reach net-zero emissions. Similar to the argument for netting $MMTCO_2e$ rather than each type of greenhouse gas, netting emissions economy-wide achieves the legislative objective of limiting the impacts of climate change; netting by sector provides no incremental benefit. However, estimating emissions by sector may provide insight into the efficacy of our greenhouse gas emissions reduction strategies if data and tools are available to do so.

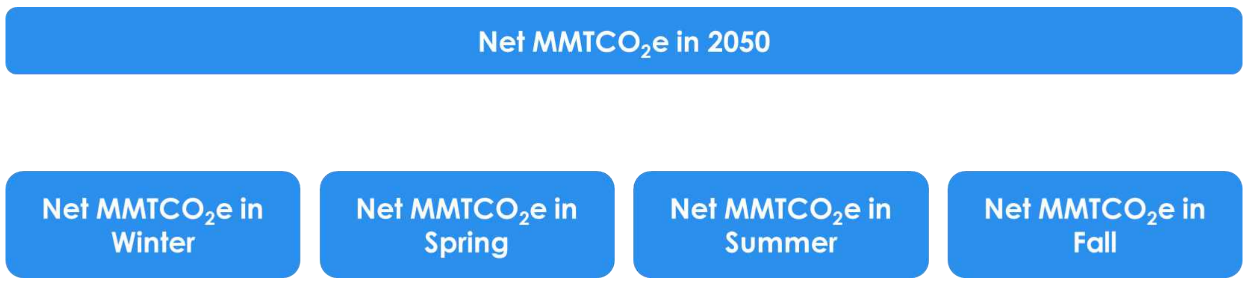
Stakeholders raised two critical concerns about the net-zero emissions mandate. First, stakeholders feared that netting emissions may alleviate a sense of urgency to reduce emissions sources; folks may rely too heavily on as-yet-developed future technology to remove greenhouse gases from the atmosphere. Second, stakeholders emphasized that emissions in our atmosphere will contribute to climate change regardless of the accounting practices we use in our emissions inventory; therefore, we must prioritize actions to reduce emissions rather than dwelling on how to inventory them.

Both concerns are valid and must be addressed. We propose three immediate responses related to maintaining a sense of urgency, limiting our reliance on not-yet-developed technologies, and recognizing the shortfalls of accounting.

Regarding urgency: while this *2022 Update* defines our 2050 emissions reduction mandate, we also include priority actions needed to reach our interim 2030 emissions reduction target. Balancing the emphasis of short-term action with long-term understanding will help with identifying priorities now and developing the *2025 Climate Strategy* over the coming few years.

Regarding future technologies: the priority actions identified within this plan are all related to reducing sources of anthropogenic greenhouse gas emissions and we plan to continue to stress a 'mitigate first – net as a last resort' principle in the *2025 Climate Strategy* and subsequent updates.

Regarding accounting: our greenhouse gas emissions inventories allow us to track progress so that we can adjust course if our strategies are not working as needed. We propose to update our greenhouse gas emissions inventory alongside metrics within our climate dashboard with the objective of continual self-evaluation and improvement. We also will rely on climate experts at the IPCC, US EPA, and at Rhode Island's institutes of higher education to provide technical guidance that underlies our development of strategic policies.



Over what timeframe should we net emissions?

The process of netting emissions sums up the net of all emissions remaining in the atmosphere over a particular timeframe. Current practice is the net emissions over an annual timeframe, in which case the net of all emissions released into the atmosphere between January 1 and December 31, 2050 is required to equal zero. On the other hand, we could require net emissions to equal zero for each season, each month, each day, or even each hour.

There are tradeoffs to a longer timeframe versus a shorter timeframe. A longer timeframe – netting emissions on an annual basis – may be the most appropriate for a complex and volatile system. While more frequent netting – netting emissions sub-annually – may provide insights about seasonal emissions patterns and related emissions reduction strategies, natural randomness and volatility in our behaviors, our economy, and our environment may lead to spurious results and false insights. However, there may be some particular sectors or industries for which sub-annual netting might be appropriate. For example, industries with a defined 'season' (for example, heating) or with relatively insensitive emissions profiles (for example, some manufacturing) might benefit from more frequent netting to obtain more real-time feedback on emissions reduction strategies.

Two additional key considerations are our capabilities and the administrative burden of inventorying greenhouse gas emissions. First and foremost, our capabilities are dependent on capabilities built into existing inventory tools. At this time, we do not have the capability to track emissions on a daily or hourly basis. As tools evolve to include additional flexibility, then our capabilities may evolve as well. Given these capabilities, we want to strike the right balance between getting feedback on our strategies with actually doing the work called for by our strategies; and, importantly, we want to make sure the administrative work we do to measure emissions provides incremental and actionable insights. We propose continuing annual netting at this time, but reassessing capabilities, resources, and benefits within the *2025 Climate Strategy* and each subsequent iteration.

Exogenous limitations

Rhode Island should continue to align with best practices for greenhouse gas inventorying. We do so by leveraging inventory tools developed and maintained by the US EPA, and we rely on the US EPA to update these tools to be consistent with the recommendations of the IPCC.[15] We do not envision Rhode Island developing its own tools, but we will strive to improve methods using the most specific data available for Rhode Island as well as the most recent science and coordinate accounting methodologies with the federal government and neighboring states. We can advocate for the US EPA to develop and enhance these key capabilities in future evolutions of their greenhouse gas inventory tools. Furthermore, our Triennial Greenhouse Gas Emissions Inventory provides insights beyond a single point estimate of greenhouse gases by including a discussion of how this point estimate may be sensitive to certain assumptions and therefore imprecise or biased.

Non-quantitative metrics and lived experience

While our climate mandates entail specific greenhouse gas emissions reductions, the 2021 Act on Climate also discusses the need for strategies regarding climate justice, community resilience, and improving public health. These objectives cannot be represented by a single value of $MMTCO_2e$, so we cannot lose sight of the importance of non-quantitative metrics and lived experience. While this chapter discusses technical accounting methodology for estimating our greenhouse gas emissions, we should also continue to provide opportunities to lift up voices from communities across Rhode Island to share their experiences and trust their expertise on priority actions and success (or failure) of our climate strategies.

Greenhouse Gas Emissions Inventory Process, Methodology, and Tools

Stakeholders suggested the development of the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* is a ripe opportunity to reconsider and confirm technical aspects of modeling. The objective of this chapter is to describe current emissions inventory processes, methodologies, and tools in order to highlight changes since 2016 and understand the status quo. Much of this content is adapted from the 2019 Rhode Island Greenhouse Gas Emissions Inventory. We refer interested readers to that report for more detail. [16]

We then describe two central principles governing how and when we update process, methodologies, and tools specifically related to the 1990 baseline and estimating emissions from the land use, land use change, and forestry (LULUCF) sector. We also include explicit actionable recommendations for additional analysis in support of the development of the *2025 Climate Strategy*, as well as recommendations for improving transparency of how Rhode Island will assess interim compliance with the 2021 Act on Climate.

Methodologies

The Rhode Island Department of Environmental Management (RIDEM) is the state agency responsible for estimating Rhode Island's greenhouse gas emissions. RIDEM's Office of Air Resources estimates emissions on a calendar-year basis. For example, the 2016 emissions inventory estimates emissions resulting from activities that occurred between January 1, 2016 through December 31, 2016, inclusive of the end dates. For all inventories, there is a three-year lag between the year of emissions and the year of the inventory. For example, Rhode Island's 2016 emissions inventory was estimated in 2019. Similarly,

[15] Specifically, Rhode Island uses the US EPA SIT, the US EPA MOVES, and a method developed in-house based on methodology developed by Massachusetts and Connecticut to estimate emissions from the electric sector. We refer interested readers to the most recent Rhode Island Greenhouse Gas Emissions Inventory for additional technical detail.

[16] Available online at https://dem.ri.gov/environmental-protection-bureau/air-resources/greenhouse-gas-emissions-inventory

Rhode Island's 2019 emissions inventory was released in December 2022. Unless otherwise noted, the emissions inventory year (e.g., '2016 emissions inventory') corresponds to the year in which the emissions resulted, not the year in which estimation occurred. This lag time is caused by reliance on multiple federal and state agencies' dataset releases, and the time required to collect data and modify emissions inventory tools. Rhode Island must endure this lag time to access US Environmental Protection Agency's (EPA) emissions inventory tools, which are necessary to complete Rhode Island's emissions inventory.

- Rhode Island should coordinate with other states to request the US EPA shorten the lag time from three years to one year or less.

Like many other states that regularly preform economy-wide greenhouse gas emissions inventories, Rhode Island relies heavily on the US EPA's State Inventory Tool (SIT). The tool is an interactive top-down spreadsheet designed to help states develop GHG emissions inventories. The SIT consists of 11 modules which calculate sector-by-sector greenhouse gas emissions based on numerous state-level data sets, including energy-related data provided by the US Energy Information Administration (EIA). When state level data are likely to be more robust than the tool's default data, the US EPA recommends that states employ their own data.

The SIT estimates GHG emissions by applying pollutant-specific emission factors to Rhode Island activity data. The US EPA updates the SIT annually with the latest activity data. If needed, any updates to emission factors and/or parameters like global warming potentials are made as well. Greenhouse gas emissions are converted to a summary unit of measure called million metric tons of carbon dioxide equivalent ($MMTCO_2e$) based on their global warming potentials that allows for better comparison of the impact of different greenhouse gases. These conversions are completed within the SIT.

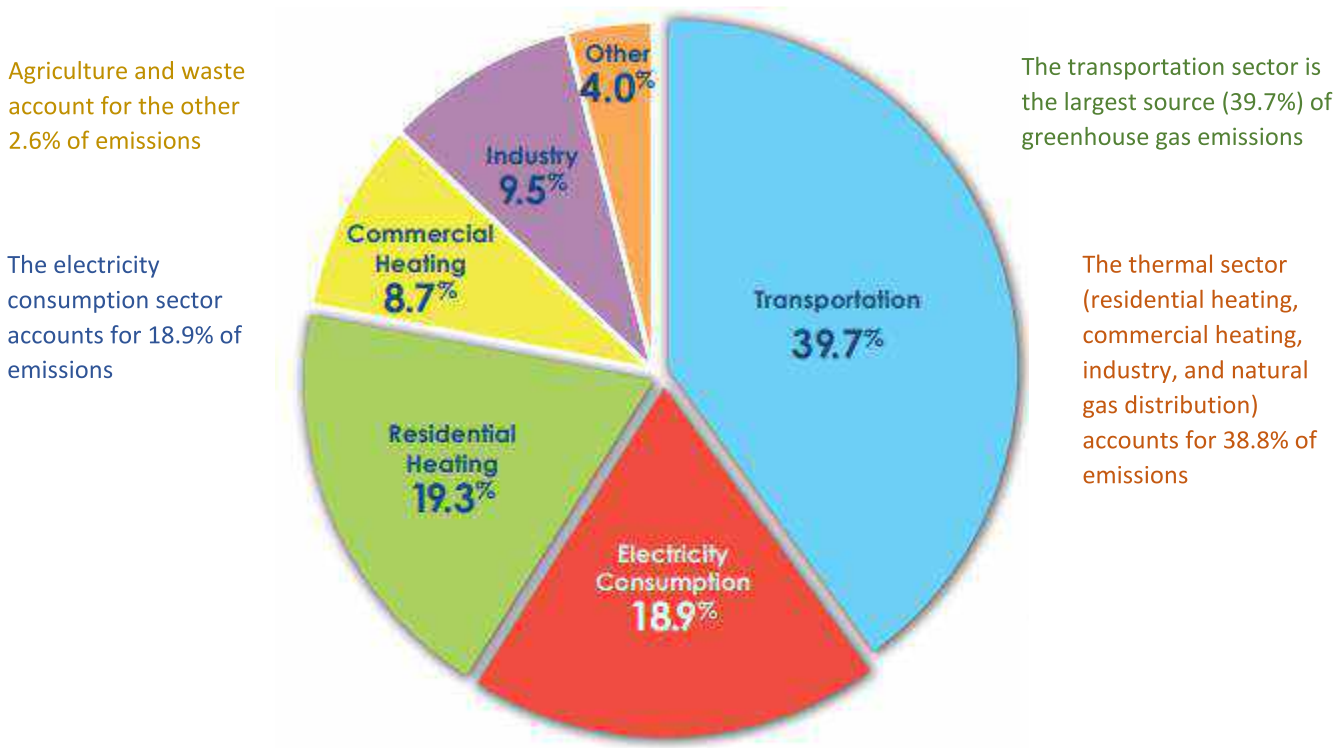
RIDEM releases annual greenhouse gas emissions inventories. Every three years, RIDEM publishes a "triennial summary" that coincides with the releases of the US EPA's triennial National Emissions Inventory.[17] Each National Emissions Inventory details emissions of criteria air pollutants, criteria precursors, and hazardous air pollutants. Triennial greenhouse gas emissions summaries provide a greater level of detail than annual emissions inventories. Table X below displays the history of default versus non-default model runs. All inventories since 2013 were non-default runs and RIDEM anticipates using non-default runs for all future emissions inventories. In these years, state-specific data was utilized to obtain the most robust emissions estimates. Inventory years 2011 and 2012 were default runs for which emissions were estimated using primarily default data in the SIT. This default data relies on top-down estimates rather than bottom-up primary data collection. Non-default model runs are considered more precise. Consistent methodologies – even with differently sourced data –still allows for comparisons of emissions estimates from year to year. However, caution should be applied when comparing emissions estimates year-over-year when we expect the results to be biased differently when using default versus non-default data. See the callout box on *The Role of Models* below for additional explanation.

[17] As described in the *2016 Greenhouse Gas Emissions Reduction Plan*, Monitoring, Page 26.

Table X. Model Run Types by Emissions Inventory Year.

Rhode Island Greenhouse Gas Emissions Inventory											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Triennial Summary Released	No	No	No	No	No	No	No	Yes	No	No	Yes
Model Run Type	Non-Default	Non-Default	Default	Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default	Non-Default

Some categories of emissions require other tools and methods instead of or in addition to the SIT. All of RIDEM's tools provide emissions estimates in $MMTCO_2e$ for each of the nine emissions categories: transportation, electricity, residential heating, commercial heating, industry, waste, natural gas distribution, agriculture, and land use, land use change, & forestry. We summarize these emissions estimated for 2019 below; these sectors – transportation, electricity, and thermal[18] – correspond to the following chapters that identify priority actions to reduce emissions.



Source: RIDEM 2019 Greenhouse Gas Emissions Inventory. Please note that data are consistent, but in this document the Thermal Sector includes the following distinct sectors: residential heating, commercial heating, industry, and natural gas distribution.

[18] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we do *not* include emissions caused by methane leakage from the natural gas distribution system within the electric sector and instead reference this source of emissions within the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

Rhode Island's first greenhouse gas emissions inventory was completed in 2013 with the support of experts from the Northeast States for Coordinated Air Use Management.[19] This first analysis estimated both a 1990 baseline and emissions inventory for 2010, the most recent year for which data was available at the time. Since this first analysis, RIDEM has continued to complete annual emissions inventories. In the sections below, we provide a high-level summary of how emissions are estimated and highlight changes since the *2016 Plan* was developed.

In the spirit of focusing our efforts around the most impactful and immediate priority actions to reduce Rhode Island's emissions, we limit the discussion in this chapter to the emissions sources that have readily available solutions for decarbonization. Therefore, we provide in-depth descriptions and discussions of methodologies for the three largest contributors to Rhode Island's greenhouse gas emissions: transportation, electricity consumption, and residential heating. We do not provide in-depth discussions of how we estimate emissions from commercial heating, industry, natural gas distribution, waste, or agriculture – each of these sources, while critically important for reaching net-zero emissions, is small in comparison and has relatively limited or nascent solutions for decarbonization. We recommend further attention to these sectors in the development of the *2025 Climate Strategy*. We do, however, provide an in-depth discussion of methodology and considerations around estimating the emissions impacts of land use, land use change, and forestry (LULUCF).

The Role of Models

> *A model is a way to describe something that happens in the world around us. A model does not dictate what happens, nor does a 'right' model exist. Models are tools that we use to understand how one variable affects another. In this vein, it is important to understand the value of – and the limitations of – the models we employ.*
>
> *A model should be as simple or complex as needed to attain the requisite levels of precision and accuracy given objectives and available resources. A simpler model typically needs fewer resources than a complex model because there is less data to be collected, less time used to run the model, etc. If a simple model is sufficiently precise and accurate for the user, then there is negligible value to making the model more complex.*
>
> *Precision is the concept of how reproducible the results of the model are – a precise model consistently gives similar results. However, a precise model may give consistently inaccurate results. In statistics, we can estimate precision using established methods and tests. For example, an econometric model reports out what-are-called 'standard errors,' which help a user understand whether the model's results are the result of real underlying relationships or are spurious.*[20] *Precision is important to understand when we compare results because it would be inappropriate to attribute differences between imprecise results to a specific reason. You might hear terms like 'statistical significance', 'variability', and 'uncertainty' when discussing precision.*
>
> *Accuracy is how close a model's results are to the truth, which may or may not be known. An accurate model may not be precise. If a model is expected to consistently underestimate or*

[19] Northeast States for Coordinated Air Use Management (NESCAUM) is a non-profit organization: https://www.nescaum.org/.

[20] Precision is a concept that exists across disciplines. For example, engineers may be familiar with the concept of 'tolerances' to describe required precision of machining and manufacturing. Scientists have developed standardized methods for assessing precision of measurements, such as by completing multiple counts of the same sample or by taking multiple samples of the same population.

overestimate a result, then we say that result is 'biased'. In the models we use to estimate Rhode Island's emissions, it is the responsibility of the people doing the estimation to understand if and how results are biased.

Results from any model should not live in isolation, and any isolated facts or figures should be considered incomplete results. Complete results must discuss precision and bias, and should include discussion of the validity of the model.

The methodology used to estimate Rhode Island's greenhouse gas emissions inventory does not report any measures of precision or imprecision. However, the SIT does provide some helpful insights into uncertainties in the default data provided. RIDEM assesses the validity of the data and the factors that influence emissions to inform their understanding of how precise our emissions results are, especially as we compare emissions year-over-year. Having some standardized guidance from the US EPA on the precision of their models' results would help Rhode Island (and other states) properly contextualize emissions inventory results.

- States should request the US EPA develop methods to assess precision to be integrated into their emissions inventory tools.

Transportation Sector Emissions

Emissions from the transportation sector include emissions from highway vehicles,[21] aviation, marine transportation, gas and diesel off-road vehicles, locomotives, and more.

Table X. Emissions from the Transportation Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Transportation Total	**4.97**	**4.33**	**4.40**	**4.19**	**4.59**	**4.25**	**4.09**	**3.94**	**4.17**	**4.45**	**4.29**
Aviation	0.33	0.27	0.31	0.29	0.29	0.30	0.28	0.30	0.34	0.38	0.30
Highway Vehicles	4.38	3.70	3.76	3.62	4.10	3.62	3.66	3.62	3.57	3.85	3.61
Nonroad Sources	0.27	0.36	0.33	0.28	0.20	0.32	0.12	0.02	0.25	0.23	0.38

Bottom-Line Factors that Reduce Transportation-Sector Emissions

1. Reducing fuel use reduces emissions
2. Using lower-emissions fuels (like electricity) reduces emissions

Current Method

Several tools are available to calculate greenhouse gas emissions from the transportation sector. The US EPA recommends the SIT for the entire sector and the Motor Vehicle Emissions Simulator (MOVES) for highway vehicles only. The SIT and MOVES models vary in the amount of precision at the state level.

[21] A highway vehicle is any type of on-road vehicle (e.g. passenger car, passenger truck, light commercial truck, heavy-duty trucks, etc.) that uses any fuel type.

The SIT uses a top-down approach to calculate emissions from transportation, starting with fuel consumption and vehicle miles traveled. This approach uses data on fuel sales within each state as a proxy for fuel consumption. The major shortcoming of this method is a lack of detail; drivers do not always use their vehicles in the same state that they purchase fuel. As a result, fuel sales may provide an imprecise estimate of fuel consumption at the state level. Data on fuel sales also do not provide information on different types of on-road vehicles.

MOVES is an all-in-one program that estimates emissions using a "bottom-up" approach. Vehicle miles traveled and vehicle data determine fuel consumption and emissions produced. The tool requires many user-supplied inputs and simplifies the analysis at different geographic levels. For the purpose of state emissions inventories, US EPA recommends county level inputs requiring the user to supply local, state, and county data. Inputs to MOVES include data on vehicle population, vehicle age, average speed distribution, meteorological data, inspection and maintenance program details, road type distribution, and vehicle miles traveled. The model simulates vehicle drive cycles for the defined time period and geographical area specified. Data from all five Rhode Island counties are summed to produce a transportation sector inventory.

Although MOVES provides the strongest and most current methods for analyzing the greenhouse gas emissions of on-road vehicles, the tool is not the best option for estimating emissions from non-road modes of transportation. Instead, the SIT is used to determine emissions from aviation and other non-road sources. Some examples of non-road sources are boats, locomotives, tractors, construction equipment, snowmobiles (gasoline only), and lubricants. For aviation related greenhouse emissions, the Rhode Island Airport Corporation (RIAC) provides RIDEM with an annual inventory of greenhouse gas pollutants associated with the State's primary airport, T.F. Green International Airport.

Notable Changes

Rhode Island's emissions inventories for years 1990, 2010-2012, 2018, and 2019 used the SIT only; those inventories did not use MOVES to estimate emissions from highway vehicles. MOVES was used for years 2013-2017 to estimate emissions from the highway vehicle sub-sector. As such, transportation emission totals for years 1990, 2010-2012, 2018, and 2019 should be interpreted as being less precise than transportation emissions for years 2013-2017.

Notes on the 1990 Baseline

The 1990 baseline was estimated using only the SIT. Transportation emissions today relative to the existing 1990 baseline would not be an apples-to-apples comparison because the core methodology is different.

Limitations of the Model

The SIT distinguishes between alternative fuel vehicles and petroleum-powered vehicles. Categories of alternative fuel vehicles include methanol, compressed natural gas, liquified petroleum gas, and ethanol. Electric vehicles are not considered alternative fuel vehicles in the SIT. Emissions resulting from the electricity consumed in charging electric vehicles are also accounted for in the electricity consumption sector of Rhode Island's greenhouse gas emissions inventory. MOVES also does not distinguish between electric and non-electric vehicles, which results in overestimating emissions from electric vehicles in two ways.

First, because the tools cannot distinguish between electric and non-electric vehicle types, emissions from electric vehicles are assumed – incorrectly – to be equivalent to emissions from gas-powered vehicles.

Fortunately, emissions from electric vehicles using electricity from the renewable- and fossil-based generators we have today are less than the emissions from gas-powered vehicles.

Second, the emissions from electric vehicles are double counted because they appear (incorrectly) in the transportation sector emissions estimates and (correctly) in the electric sector emissions estimate. Currently, this overestimation is negligible since electric vehicles comprise only a small portion of the Rhode Island market (as of 2021, slightly less than one percent of vehicles registered were electric). This overestimation will grow as more and more Rhode Islanders adopt electric vehicles.

- States should request the US EPA amend the greenhouse gas emissions inventory tools to correctly account for emissions resulting from electric vehicles.

Electric Sector Emissions

Emissions from the electric sector result from electricity consumed[22] within Rhode Island. Rhode Island's increasing Renewable Energy Standard and continued energy savings from energy efficiency programs, both of which reduce emissions, have mitigated the magnitude of emissions increase that we would have seen absent those activities.

Table X. Emissions from the Electric Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018*	2019
Electricity Consumption	2.82	2.29	3.38	3.38	3.52	3.25	3.21	2.84	3.31	2.33	2.05

** Revised 2018 electricity sector emissions*

Bottom-Line Factors that Reduce Electric Sector Emissions

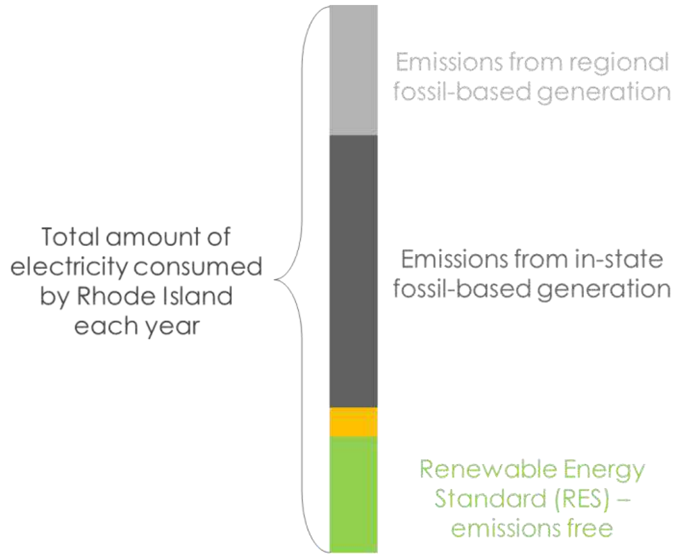
1. Reducing electricity consumption reduces emissions.
2. Producing electricity with renewable energy reduces emissions and appropriately crediting RIs investment in renewable energy in the inventory

Current Method

Rhode Island's current method for estimating emissions from the electric sector is based on annual state-wide electricity consumption. Both Massachusetts and Connecticut also rely on this method for their annual emissions inventory. The electric sector emissions inventory includes three primary components (illustrated in the figure below): compliance with the Renewable Energy Standard (RES),[23] emissions of in-state fossil-based electricity generation, and emissions of fossil-based electricity from our regional electric grid.

[22] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we do *not* include emissions caused by methane leakage from the natural gas distribution system in this section and instead reference this source of emissions within the section on emissions from the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

[23] RIGL 39-26



First, we account for emissions-free electricity in compliance with Rhode Island's RES, requires we meet an increasing portion of our electricity consumption with renewable energy. Electric distribution companies and non-regulated power producers comply with the RES by supplying an increasing percentage of their retail electric sales from renewable energy resources. Eligible renewable energy resources include solar, wind, wave, geothermal, small hydropower, biomass, and fuel cells.

RES compliance does not involve the physical delivery of electricity produced by renewable energy facilities. Instead, electricity providers meet the requirements of the RES mandate by purchasing renewable energy certificates (RECs), which each represent the environmental attributes associated with one megawatt-hour (1 MWh) of renewable energy generated and delivered to the electric grid at some point throughout the year.

RES compliance can also be demonstrated by making alternative compliance payments (ACPs) to the Rhode Island Commerce Corporation (Commerce RI) Renewable Energy Fund. The ACP functions as a price ceiling, allowing electricity providers to comply with the RES mandate if REC shortages occur. Commerce RI uses the Renewable Energy Fund (REF) to support the development of new renewable energy projects. In turn, these projects generate RECs, theoretically helping to ameliorate tightening of the REC market.

This portion of electricity consumed that resulted in ACPs rather than retiring RECs cannot be considered to be emissions-free. Rather, this portion of our electricity consumption has emissions proportional to the emissions resulting from our in-state and regional electric grids. Emissions from this portion of electricity consumption comprise Rhode Island's total electric sector emissions – as we increase the RES, all else equal, emissions will decrease. We estimate these emissions by first assuming all in-state fossil-based electricity generation is consumed in state, and then pro-rate emissions from regional fossil-based electricity generation required to be imported into the state to satisfy consumption. As other states enact RES-like mandates and as market dynamics evolve to favor lower-emissions generation, emissions will decrease, all else equal.

We can walk through this method using the 2018 emissions inventory as an illustrative example; these steps are also detailed in the figure below. In 2018, Rhode Island consumed approximately eight billion kilowatt-hours (kWh) of electricity.[24]

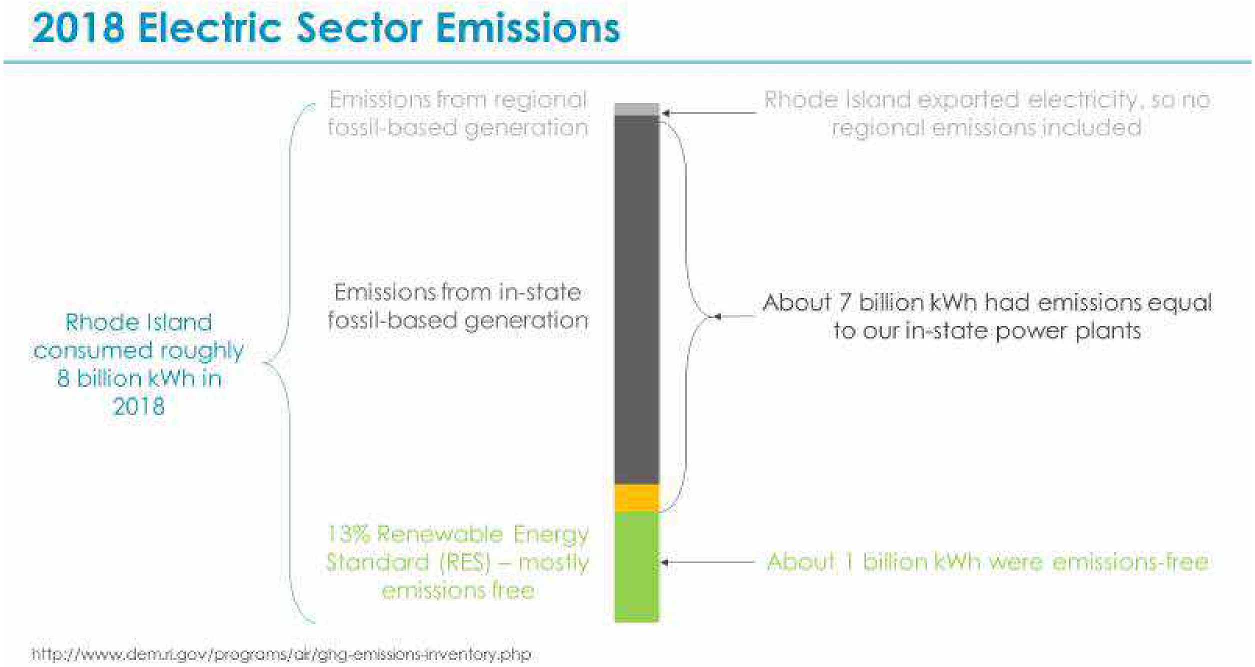
In 2018, the RES required 13% of electricity consumption be met with renewable energy. Of this 13%, nearly all was offset through the purchase (and retirement) of RECs. This portion of electricity consumed – equal to about 1 billion kWh – is deemed to have zero emissions.[25] The small portion of compliance through ACPs – roughly 30 million kWh – cannot be considered to be emissions-free.

In 2018, Rhode Island had six electricity generators, five of which used natural gas and one of which used landfill gas. These six generators produced a little more electricity than the total amount of electricity Rhode Island consumed in 2018. Therefore, emissions for roughly seven billion kilowatt-hours of emissions-intensive electricity consumed equaled the emissions produced by in-state fossil-based generators.[26] If those power plants had produced less than the equivalent of the amount of electricity consumed by Rhode Island, as was the case in 2016, the emissions from the remaining amount of electricity would be deemed to be proportional to emissions from the fossil-based fuel mix that supplies our regional electric grid.

[24] We present electricity consumption in units of kilowatt-hour (kWh) because readers may be familiar with this unit from electricity bills. We could present electricity consumption (or generally) equivalently as 8,000 gigawatt-hours (GWh) or 8 million megawatt-hours (MWh).

[25] Some readers may ask how our retail renewable energy programs fit in here – the answer is that it all depends on who retains ownership of the RECs generated and what they do with them. People who have renewable energy systems through the REG program (National Grid's feed-in-tariff program) sign over ownership of all RECs generated to the utility. The utility then retires those RECs to meet its own obligation under RES – in other words, those RECs count toward reducing Rhode Island's emissions. In contrast, people who own their own renewable energy systems that are net metered retain ownership of the RECs generated for those systems. In order to measure the RECs generated, these systems need additional technology that meets required specifications (i.e. a revenue-grade meter to measure renewable energy production). For residential systems, individuals usually don't install this technology. Therefore, the generation of these systems doesn't count toward Rhode Island's compliance with RES, but it does have the effect of reducing our statewide electricity consumption. From 2018, Rhode Island consumed eight billion kilowatt-hours of electricity *plus* the amount of emissions-free electricity generated by these direct-owned net metered systems. Net metered systems that are direct owned or owned by third parties, and that have the technology to measure REC generation (this is more common for commercial systems), may have their RECs sold to meet Rhode Island's RES *or* another state's RES. If the RECs are retired in Rhode Island, then they reduce our emissions. If the RECs are retired in another state, then they reduce that other state's emissions.

[26] Some readers may ask how Rhode Island's participation in the Regional Greenhouse Gas Initiative (RGGI) fits in – the short answer is that it helps us reduce our carbon dioxide emissions both regionally by encouraging carbon abatement measures and generating revenue to support emissions reductions. If our in-state fossil-based generators abate their emissions to comply with RGGI, then Rhode Island's emissions decrease. If those generators instead buy allowances to produce emissions, then we receive some portion of revenue that we then allocate to programs like energy efficiency and renewable energy incentives, which in turn reduce our emissions.



Annual versus Hourly Electric Sector Emissions

The emissions that result from consuming a unit of electricity on a hot, humid summer evening are different from the emissions that result from consuming the same unit of electricity on a pleasant fall day. This is because the systems that generate electricity differ based on time of day and how much electricity is needed.

On hot and humid summer evenings, when individuals are getting home from work and turning their air conditioners on, the region typically needs the most electricity out of the entire year (called 'peak electricity demand').[27] *Our region's renewable energy sources tend to generate less electricity during summer evenings (when the wind calms down and the sun sets), so our electricity needs must be met by fossil-fueled electricity generators. To satisfy electricity demand during these peak hours, the New England electric grid relies on additional natural gas power plants and occasionally on oil- and coal-based power plants (less than one percent of the region's electricity comes from these highest-emitting sources). Therefore, emissions from overall electricity consumption and emissions per unit of electricity consumed both increase during times of peak electricity demand.*

In contrast, on pleasant fall days we tend to leave our heating or air conditioning systems off, and since individuals tend to be at work, we aren't running appliances like dishwashers and washing machines. During these times, our renewable energy resources tend to have more output, too. The relatively small amount of additional electricity we need to satisfy our demand during these off-peak hours can be derived from our region's emissions-free nuclear power plants plus some natural gas power plants. Therefore, at certain times of the year, like pleasant fall days, our

[27] The timing of when peak electricity demand occurs is anticipated to shift to winter months as we electrify thermal and transportation sectors. For more information about peak demand, visit the US Energy Information Agency.

emissions are lower both because we consume less electricity and the little electricity we consume comes from sources with relatively low emissions.

Rhode Island's current practice and capability is to estimate emissions on an annual basis, but this method does not distinguish between electricity used at times when resulting emissions are high and electricity used at times when resulting emissions are low. For example, electricity produced using renewable energy resources generates RECs which can be used to offset emissions from fossil-based electricity generated at any time of the year – the RECs are not specific to a single hour. Rhode Island and its regional partners should revisit the idea of more granular emissions accounting as technology and capabilities allow within the next decade.

Notable Changes

Prior to the 2016 emissions inventory, Rhode Island used the SIT to account for electric sector emissions. However, the SIT does not accurately account for emissions reductions from state policies like the RES. This change in methodology prevents robust comparison of electric sector emissions before and after 2016.

Notes on the 1990 Baseline

The 1990 baseline was originally estimated with the SIT. After the publication of the *2016 Plan*, the 1990 baseline's electric sector emissions were adjusted. Comparing electric sector emissions today relative to the existing 1990 baseline would not being comparing apples-to-apples because the underlying methods differ.

Limitations of the Methodology

This methodology does not account for the varying rates of emissions across hours of the year. Renewable energy systems generate more electricity during times when the marginal fossil-fueled power plant uses natural gas. However, peak electricity demand occurs when the marginal power plant uses a more emissions-intensive fuel. Since RECs produce by renewable energy are not time-stamped, those RECs may theoretically offset more emissions-intensive electricity consumption than the renewable energy resources actually did. Therefore, this methodology is likely to result in underestimating emissions from the electric sector. See the callout box on *Annual versus Hourly Emissions* for additional discussion. Methodology changes for the most recent inventory year, 2019, are discussed in the *2019 Rhode Island Greenhouse Gas Emissions Inventory*. We suggest consistent revisions to the electricity sector methodology as accounting capabilities and economic markets evolve.

Impacts of Strategic Electrification

Strategic electrification is one pathway to reducing greenhouse gas emissions. By transitioning transportation and heating away from technologies that require fossil fuels to those that use electricity – and then meeting our growing electricity needs with renewable energy resources – we will reduce emissions in the transportation and heating sectors. [28]

[28] The GHG emissions from registered in Rhode Island (i.e. from charging) are counted in the electricity sector, not the transportation sector. When there are significantly more EVs registered in Rhode Island, their vehicle mile traveled (VMT) contribution will be omitted from the overall VMT. This will avoid double-counting their emissions between the transportation and electricity sectors. Since VMT from EVs would be omitted from the transportation sector, overall transportation sector emissions would DECREASE. The 2033 100% RES should mitigate additional emissions by EVs in the electricity sector. In theory, we could adopt as many EVs as we want and still have 0 MMTCO2e with the electric sector by 2033.

As we electrify heating and transportation, a growing proportion of heating and transportation emissions will be captured within the electric sector emissions inventory. This has two effects. First, to the extent our thermal sector and transportation sector emissions inventory tools account for electrification, the decreases we will see in emissions in transportation and heating sectors will be exaggerated because those emissions will be included in the electric sector emissions inventory. We will need to make sure we use caution when using sector-specific emissions to assess the efficacy of our climate strategies to avoid thinking we have made more progress than we actually have. Second, emissions in the electricity sector will grow as people electrify their vehicles and heating systems. This growth in electricity consumption – and, depending on timing of renewable energy deployment, of electric-sector emissions – may result in obscuring progress we are actually making with our climate strategies.

- *For these reasons, among others, it is important for Rhode Island to track metrics beyond greenhouse gas emissions in order to evaluate progress accurately and clearly. Such metrics may include, but are not limited to, proportion of vehicles that are electric, census of heating system fuel types, prevalence of these technologies across communities, and others.*

We also have to be increasingly careful with our terminology. 'Thermal sector emissions,' which is comprised of residential heating, commercial heating, industrial heating and processes, and natural gas distribution, may become an increasingly incomplete representation of all emissions from the thermal sector. 'Electricity sector emissions' as used in the emissions inventory will increasingly include more end uses than in the past and therefore may take on a broader interpretation than is used colloquially today.

- *If, and until, we have tools that disaggregate state-level electricity consumption by end use, we must strive to be more precise in our choice of terminology. Instead of shortening to 'thermal sector emissions', we should strive to say 'emissions from combustible fuels used for heat'; instead of 'transportation sector emissions', say 'emissions from combustible fuels used for transportation.'*

Residential Heating Emissions within the Thermal Sector

Emissions from the thermal sector result from the sub-sectors of residential heating, commercial heating, industrial processes that require heat, and natural gas distribution. [29] Residential and commercial heating include space heating, water heating, and cooking. The five sub-sectors are each estimated separately. Emissions resulting from heating, cooking, and heat processes that use electricity are captured in the electric sector emissions inventory and are not reflected in the thermal sector inventory. [30] Below, we describe the methodology used to estimate emissions from residential heating only.

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[29] Note that in the Annual Greenhouse Gas Emissions Inventory, emissions caused by methane leakage from the natural gas distribution system are aggregated with emissions from electricity consumption under the label 'emissions from the energy sector.' This is because Rhode Island's in-state power plants rely on natural gas to generate electricity. However, we instead include this source of emissions within the thermal sector. The purpose of this choice is to showcase natural gas's role in heating.

[30] Since cooling relies on electricity, emissions resulting from cooling – residential, commercial, or other – are captured in the electric sector emissions inventory.

Table X. Emissions from the Thermal Sector

Rhode Island Greenhouse Gas Emissions Inventory											
Updated November 15, 2022. All emissions reported in $MMTCO_2e$.											
	1990	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential Heating	2.37	2.24	2.15	2.08	2.27	2.34	2.46	1.84	1.87	2.32	2.09
Commercial Heating	1.15	0.92	0.87	0.79	0.91	1.13	1.00	0.86	0.88	0.98	0.94
Industry	0.81	1.04	1.06	1.05	1.24	1.14	1.12	1.14	1.12	1.19	1.03
Industrial Heating	0.71	0.61	0.56	0.54	0.67	0.57	0.59	0.61	0.62	0.63	0.61
Industrial Processes	0.09	0.43	0.5	0.51	0.56	0.57	0.53	0.53	0.50	0.55	0.42
Natural Gas Distribution	0.3	0.15	0.15	0.15	0.17	0.17	0.16	0.15	0.15	0.14	0.14

Bottom-Line Factors that Reduce Thermal Sector Emissions

1. Reducing combustible fuel use (like natural gas, oil, and propane) reduces emissions.
2. Using lower-emissions fuels (like biodiesel or electricity) reduces emissions.

Current Method

Residential heating emissions are estimated using the SIT's Carbon Dioxide from Fossil Fuel Combustion (CO_2FFC) module and the Stationary Combustion module. The US Energy Information Administration (EIA) collects fuel consumption data throughout the United States by requiring mandatory surveys for all companies that deliver natural gas to consumers, usually through pipelines, or transport natural gas across state lines.

Distillate fuel, propane, and kerosene are examples of fuels that are usually trucked to Rhode Island homes that use them for heat. These are therefore called 'delivered fuels'. Consumption estimates for delivered fuels are estimated by the EIA. Fuel consumption data is a key component to estimate emissions.

Notable Changes

There have not been any appreciable changes to methodology for estimating emissions from residential heating.

Notes on 1990 Baseline

The 1990 baseline is fairly comparable to current emissions inventories; the methodology has not changed. However, there has been a change to a specific parameter used to account for the impact different types of emissions on climate change – this parameter is called global warming potential (GWP) and it is particularly important within estimating thermal sector emissions because of the types of greenhouse gases associated with thermal sector emissions. See the following section on When to Update the 1990 Baseline for more information. Rhode Island's 1990 baseline and 2010 emissions inventory used different GWPs than emissions inventories for 2011-2019. Comparing emissions from our 2019 emissions inventory to the 1990 baseline is not a direct comparison. However, the effect of this change in GWPs is likely to be small relative to total emissions.

Limitations of the Model

Rhode Island enacted and subsequently updated the Biodiesel Heating Oil Act to require the mixing of biodiesel in heating oil. Biodiesel is a renewable fuel made from plant or animal based materials or waste. Biofuel can be mixed with conventional heating oil to create different blends of oil. For example, a B5 blend contains 5% biodiesel and a B50 blend contains 50% biodiesel. In 2019, Rhode Island required a B5 blend. The Biodiesel Heating Oil Act requires Rhode Island to be at least a B50 blend by 2030.

Biodiesel reduces emissions because it burns cleaner than conventional oil. Currently, biodiesel is not included in the emissions inventory due to a lack of state-level data on biofuel consumption. Residential heating emissions are likely to be overestimated because this inventory's calculations do not include the use of blended biofuels, and this overestimation is likely to be exacerbated as we increase biofuel blending.

- We recommend modifying tools and methods to account for blending of biodiesel by 2025 (i.e. for the 2022 emissions inventory). Strategies to do so include joining with other states to request that the EPA modify their tools or developing an alternative methodology specific to Rhode Island's needs.
- We recommend including supplemental analyses like this at key intervals to gain better insight into the efficacy of our actions.

When to Normalize

One key driver of emissions from the thermal sector is the year-to-year variation in how cold our winters are. Due to larger-scale climate processes and natural stochasticity of weather, some winters are colder than others, which lead to using more fuel to heat, and therefore to higher emissions. The opposite is true, too – warmer winters mean less heating is required and therefore less fuel is burned, resulting in fewer emissions. Since each year is different, it makes it hard to feel like were comparing apples-to-apples across years.

One way to track progress over years is to 'normalize' emissions for weather conditions. 'Normalizing' is a common process in data analysis in which you factor out whatever exogenous variable might be preventing you from seeing clear trends. For example, we can measure how cold a winter is by calculating the number of what-are-called 'heating degree days.' Heating degree days provide useful information about the coldness or warmness of any particular winter. Heating degree days are calculated by subtracting the average daily temperatures from a baseline temperature of 65°F. 65°F is deemed to be the temperature at which neither air conditioning nor heating are required to maintain a comfortable indoor temperature. The concept of heating degree days is tricky because there can be multiple heating degree days in a 24-hour period.

There are various ways to normalize emissions for heating degree days, the simplest of which is to divide emissions by the number of heating degree days each year. If emissions per heating degree day decreases over time, then we can say with confidence that we are reducing our emissions from heating. Another factor we might consider normalizing emissions for might be population. As population grows in Rhode Island – something that is arguably uncontrollable – then we expect higher emissions. However, we will be more convinced that our strategies to reduce emissions are working if emissions per person decrease over time.

Land Use, Land Use Change, and Forestry

As discussed in the Defining Net-Zero Emissions by 2050 chapter, how we use our lands and preserve our forests impacts our greenhouse gas emissions. The land use, land use change, and forestry (LULUCF) sector of our emissions inventory captures this impact.

Bottom-Line Factors that Impact LULUCF Emissions

Further avoidance of forest loss helps steady Rhode Island's ability to sequester carbon.

Current Method and Limitations

Rhode Island's small and diverse landscape is inherently difficult to account for LULUCF. 1990's LULUCF sector was estimated through a one-time contract with the NESCAUM and is not replicable. Additionally, the 2010 LULUCF estimate was calculated through the Long-range Energy Alternatives Planning (LEAP) model used in the *2016 Plan* and is not replicable. Beginning with inventory year 2019, RIDEM now estimates LULUCF with in-house data from RIDEM's Division of Agriculture and Forest Environment (DAFE) and some data from the EPA's SIT.

Carbon sequestration from forest land and urban trees, or settlement trees, account for the lion's share of LULUCF. RIDEM estimates both with in-house data provided by DAFE. Data on forest fires in Rhode Island are also provided by DAFE. The remaining LULUCF subsectors (yard trimmings, settlement soils, and agricultural soils) are derived from the SIT and comprise less than 5% of the LULUCF sector. More information on the methodology used to estimate carbon sequestration can be found in the *2019 Rhode Island Greenhouse Gas Emissions Inventory*. 2019's LULUCF sector represents a **first step** towards reliably estimating carbon sequestration in Rhode Island. This methodology should not be compared with other state's carbon removal sectors.

- We recommend RIDEM continue to collaborate with its DAFE and the U.S. Climate Alliance to continuously improve the LULUCF sector. The methodology should be replicable, consistent, and conducted in-house.
- We recommend estimating emissions from LULUCF at least every year in which we assess compliance with the 2021 Act on Climate. If the administrative burden of estimating LULUCF emissions is low and the expected variation in LULUCF emissions is high, then we may choose to estimate LULUCF more frequently.

1990 Baseline

In 2016, LEAP modeling completed for the *2016 Plan* estimated that LULUCF in Rhode Island removed 0.29 MMTCO$_2$e in 1990. This model failed to be replicable, so we cannot make accurate comparisons to 1990's LULUCF sector.

- We recommend further evaluation of using a replicable methodology for annual emissions inventories to re-estimate emissions from the 1990 baseline and subsequent years through 2018.

When to Update the 1990 Baseline

The 2021 Act on Climate sets forth greenhouse gas emissions reduction mandates relative to a 1990 baseline: reduce emissions by 45% below 1990 levels by 2030 and reduce emissions by 80% below 1990 levels by 2040. Therefore, the 1990 baseline is a critical piece of benchmarking Rhode Island's progress.

However, over time methods and models evolve to accommodate the best science. Preserving our original estimate of emissions in 1990 memorializes consistency, but results in inaccurate comparisons over time.

Updating the 1990 baseline can help us understand our emissions reductions on an apples-to-apples basis with our contemporaneous emissions inventory.

One notable example is the change to a specific parameter used to account for the impact different types of emissions on climate change – this parameter is called global warming potential (GWP). This parameter is updated routinely to reflect the most current and robust science (the impact of the emissions does not change over time, but our understanding of the impacts does). Table X shows how GWPs have changed over time.

Table X. Global Warming Potentials (GWPs)

Global Warming Potentials (GWPs)				
Type of Greenhouse Gas	IPCC Second Assessment Report (SAR)	IPCC 4th Assessment Report (2007)	IPCC 5th Assessment Report (2014)	IPCC 6th Assessment Report (2022)
Carbon dioxide (CO_2)	1	1	1	forthcoming
Methane (CH_4)	21	25	28	forthcoming
Nitrous oxide (N_2O)	310	298	265	forthcoming
Use in Rhode Island's GHG Emissions Inventories:	1990 baseline, 2010	2011-2019	N/A	N/A

Rhode Island's 1990 baseline and 2010 emissions inventory used different GWPs than emissions inventories for 2011-2019. Comparing emissions from our 2019 emissions inventory to the 1990 baseline is not a direct comparison. However, the effect of this change in GWPs is likely to be small relative to total emissions.

- We recommend further evaluation and discussion of updating the 1990 baseline if the best science suggests new and reasonable parameters or methods.

Assessing Compliance

The greenhouse gas emissions reduction mandates set forth in the 2021 Act on Climate are both mandatory and enforceable. Therefore, Rhode Island needs a clear, transparent, and comprehensive way to assess compliance with those mandates.

- We recommend RIDEM evaluate in 2023 the benefits of promulgating such regulations.

Since 2016

The 2021 Act on Climate requires this *2022 Update* to "submit to the Governor and the General Assembly an update to the greenhouse gas emission's reduction plan dated 'December 2016'." Since 2016, we've had six years of experience, progress, and lessons learned. We present this information in three different ways.

First, we review the metrics we've been tracking since 2016 – these metrics represent an outcome-oriented snapshot of how we've worked to reduce greenhouse gas emissions in Rhode Island.

Second, we inventory the numerous studies, programs, policies and pieces of legislation that have contributed to our experience with climate mitigation, resilience, and adaptation since 2016 – by doing so, we provide an easy reference for readers to connect to these resources and learnings.

Third, we directly describe progress made (or in some instances, not made) on each pathway from the 2016 Plan – these descriptions supplement the outcome-oriented metrics with a process-oriented narrative.

Some readers may find this chapter to feel repetitive – it is by design. We are attempting to describe our actions since 2016 in multiple ways, with each providing a different perspective, level of detail, and intention for use moving forward.

A Snapshot of Metrics Since 2016

For this section, we leverage the framework of metrics from the "RI Snapshot" climate dashboard maintained by the Rhode Island Department of Environmental Management.[31] The Executive Climate Change Coordinating Council (RIEC4) and its Advisory Board are developing the outline for a new climate dashboard throughout 2022, to be developed beginning in 2023.

Greenhouse Gas Emissions

Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record[32] – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Clean Energy

As of July 2022, the state has counted approximately 1,149 MW of clean energy generation capacity. Of Rhode Island's current 1,149 MW total, 430 MW is offshore wind which is mostly under contract for the Revolution Wind facility scheduled to come online in 2026, 527 MW is solar, 148 MW is onshore wind, 35 MW is landfill gas/anaerobic digestion, and 9 MW is small hydroelectric power. Including the 400 MW Revolution Wind project, approximately 85 percent of Rhode Island's current clean energy portfolio is comprised of in-state renewables or projects scheduled for adjacent federal waters. The Power Purchase Agreement for Revolution Wind was approved in 2019 with construction expected to commence in 2024.

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[31] RI in the Fight Against Climate Change: A Snapshot

[32] There is a three-year lag between the release of Rhode Island's greenhouse gas emissions inventory and the year in which emissions occurred. See the 'Greenhouse Gases' chapter for more information about Rhode Island's greenhouse gas emissions inventory, methodology, and tools.

Energy Efficiency

Since 2016, energy savings from utility energy efficiency programs has been accumulating. Table X shows energy savings for both electric and gas efficiency programs. Annual savings are savings which occur in a single year. Lifetime savings are estimated over the expected duration of installed efficiency measures.

Table X. Energy Savings from Energy Efficiency Programs 2016-2021

	National Grid	**Pascoag Utility District**	**Block Island Utility District**[33]
Electric Annual Energy Savings Cumulative 2016-2021	1,128,943 MWh	671 MWh	10 MWh
Electric Energy Savings Cumulative over Expected Lifetimes of Measures Installed 2016-2021	10,166,520 MWh	3,980 MWh	59 MWh
Gas Annual Energy Savings Cumulative 2016-2021	2,468,022 MMBtu	Not Applicable[34]	
Gas Energy Savings Cumulative over Expected Lifetimes of Measures Installed 2016-2021	26,327,149 MMBtu		

Heating

Residential and commercial heating contribute 28% of Rhode Island's greenhouse gas emissions, and industrial heat processes contribute another 9.5%.[35] In 2017, roughly half of Rhode Island homes used natural gas for heating, a third used fuel oil, a tenth used electricity, and the remainder used another fuel like propane or wood.[36]

Green Jobs

In 2021, Rhode Island had 13,809 clean energy jobs.[37] The economic aftermath of COVID-19 resulted in the loss of roughly four years of clean energy job growth, sending Rhode Island's clean energy economy back to 2016 employment levels. Clean energy job losses represented about seven percent of all jobs lost in Rhode Island's overall labor market in 2020. This decline marks the first year of job losses since the state began tracking clean energy employment in 2014. Prior to COVID-19, Rhode Island's clean energy sector had experienced a 77% increase in jobs since 2014.

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[33] Energy savings for Block Island Utility District are for November 2020 through December 2021; data do not do not include savings from the *Block Island Saves Pre-Pilot* (2015-2016) or *Full Pilot* (2016-2017). For more information about Block Island Saves, please see the Final Report.
[34] Neither Pascoag Utility District nor Block Island Utility District operate a gas distribution system or offer gas supply.
[35] 2019 Greenhouse Gas Emissions Inventory
[36] 2017 Rhode Island Renewable Thermal Market Development Study
[37] 2021 Clean Energy Industry Report

Impacts of COVID-19 – A 2020 Summary

While COVID-19 has severely disrupted life for all communities and businesses, the presence of COVID-10 does not lessen the urgency of climate change. That the 2021 Act on Climate passed in 2021 – amidst COVID-19 – is a testament to our need to mitigate the most severe impacts of climate change today and into the future. We have to be cognizant of pressures facing Rhode Islanders and consider these forces when developing future policies and programs, but climate mitigation and adaptation needs to continue to avoid overburdening communities with avoidable costs down the road.

Over the past couple years, we have felt the impacts of COVID-19 throughout our programs and our economy. We describe some but not all of the impacts here to provide some context for our progress. We discuss related impacts from supply chain distributions and real estate market dynamics elsewhere.

The economic aftermath of COVID-19 resulted in the loss of roughly four years of clean energy job growth, sending Rhode Island's clean energy economy back to 2016 employment levels. Employment across clean energy businesses declined by over 2,500 jobs (15.5%) between the last quarters of 2019 and 2020. By comparison, the overall statewide labor market declined by 7.4% during the same time. Clean energy job losses represented about seven percent of all jobs lost in Rhode Island's overall labor market in 2020. This decline marks the first year of job losses since the state began tracking clean energy employment in 2014 – prior to COVID-19, Rhode Island's clean energy sector had experienced a 77% increase in jobs since 2014.

Despite the unexpected shock of COVID-19, Rhode Island's clean energy labor market already appears to be bouncing back. Of surveyed clean energy firms in Rhode Island in the fourth quarter of 2020, four in ten indicated that they had laid off, furloughed, or reduced pay for their clean energy workers as a result of COVID-19. As of the end of 2020, three-quarters of these firms indicated that they had already brought back their laid off or furloughed clean energy staff. Job losses in 2020 were concentrated in March through May, with steady monthly job gains in June through December.

Administratively, COVID-19 made some work more difficult to move forward as facility access to implement projects was more limited in 2020 and much of the planning and stakeholder engagement moved from in-person to fully remote.

In response to COVID-19, energy efficiency programs began providing the option of a virtual home energy audit. Instead of having an energy specialist walk through a participant's home, the participant video conferences with the energy specialist and shares videos and photos of key appliances. Shifting to virtual energy audits has not only demonstrated the industry's ability to safely adapt to COVID-19 conditions, but has been shown to result in increased responsiveness, higher convenience for participants, and may improve equitable access to this resource.

COVID-19 has changed how the RI Infrastructure Bank's (the Bank's) Municipal Resilience Program operates, switching workshops from in person to online events and delaying some municipalities' participation in the program. Despite these challenges, participation in the MRP has remained strong, and online workshop events have allowed for more attendees than typically attend these events.

While the transition to remote meetings happened abruptly (starting with public workshops related to our Heating Sector Transformation report), we do not see any loss in public *participation. On the contrary, attendance at remote events has increased and participation seems to be more robust. These insights have led to continued remote opportunities for stakeholder engagement, opportunities which reduce commute times and costs, obviate the need for some services to enable participation of some people, and are felt to provide comparative benefits like ease of seeing meeting materials and ability to participate either through oral comments or via written chat.*

Even as COVID-19 restrictions ease, many are still suffering from economic and personal losses, and communities and businesses are still recovering. Our climate strategy does not exist in isolation – we must consider this ongoing context within our policies and programs. Climate action today should be designed to help communities and businesses recover by investing in our local economy, putting downward pressure on costs, and supporting improvements with simultaneous public health benefits, all while making real strides toward achieving our climate goals to mitigate the worst impacts of climate change.

Clean Cars

As of October 2022, there are 6,275 electric vehicles registered in Rhode Island. 2847 (45.4%) are Plug-in Hybrid Electric Vehicles (PHEVs), and 3,428 (54.6%) are Battery Electric Vehicles (BEVs). This represents an 1,313% increase in EVs since 2015.[38]

As of December 2022, there are 564 Level II (public and private) charging station ports, and 65 direct current fast charger (DCFC) ports. This represents a 636% increase in charging stations in RI since 2016.[39]

Protected Land

From 2010 through 2015 9,758 acres of land were protected by the state.[40] From 2016 to 2022 an additional 3,585 acres have been protected by the state [41]

Resilient Communities

As of 2022, 27 municipalities have participated in the Rhode Island Infrastructure Bank's Municipal Resilience Program (MRP). The MRP is a new program since 2019 and includes a robust stakeholder engagement approach to resilience planning. MRP workshops have hosted over 600 participants, including municipal staff and community leaders. 350+ potential resilience capital projects have been identified using this locally specialized approach.

As of 2022, 46 resilience projects have been funded through MRP Action Grants - a total of $7.5 million in assistance. 93% of MRP Action Grants have incorporated green infrastructure and/or nature-based solutions. $7 million was allocated to the MRP through the 2021 Beach, Clean Water, and Green Economy Bond, and another $16 million was allocated to the MRP through the 2022 Green Economy Bond.

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[38] Source: Rhode Island Division of Motor Vehicles
[39] Source: U.S. Department of Energy, Alternative Fuels Data Center
[40] Source: Rhode Island Department of Environmental Management, State Land Conservation Program, as of 12/31/2021
[41] RIDEM is currently collecting data on conservation projects completed at the local level by municipalities and land trusts and will add these numbers to this total in 2023.

Lead-by-Example

The Rhode Island Lead-by-Example (LBE) program was initiated in 2015. Through the end of 2021, the State has achieved an 12.7% reduction in overall State facilities' energy consumption compared to a 2014 baseline. 95% of State Government electricity consumption is offset by renewables.

In 2021, OER developed the "School Lighting Accelerator Program." This program provides technical assistance and financial incentives to Rhode Island public schools to accelerate the transition to LED lighting with controls. Through the end of 2021, five public schools in Central Falls have been converted to LED with integrated controls saving annually 471,500 kWh or $78,500. Also, 31 communities have received support to convert their municipal streetlights to LEDs with controls, representing nearly 90% of the State, and driving $5.3 million in annual cost savings. 100% of State-owned streetlights have been converted to LED lighting with controls as well.

67% of all State buildings are already or in the process of being converted to LED lighting with controls (through the end of 2021). 120 electric vehicle charging ports have been installed across State properties (through the end of 2021) and 11 solar PV systems have been installed at State facilities. 62 light duty vehicles purchased or leased since December 2015 are zero-emission vehicles (through the end of 2021).

Focus on Equity

> *Disproportionate impacts of COVID-19 on communities of color and major national events illustrating social injustice catalyzed a sincere focus on centering equity throughout our work. Historical systemic inequities have continued into our world today, which result in overburdening under-resourced communities with higher energy costs, worse public health outcomes, lower access to programs and resources, and worse environmental quality – among other things – relative to others. Rhode Island's 2025 Climate Strategy and all future plans must address these inequities. A climate strategy that fails to address climate justice will not be the best strategy for Rhode Island's fight against climate change.*
>
> *Since 2016, we've seen immense growth in understanding about equity generally and climate justice specifically. This understanding should have already been in place, and our level of understanding today is still deficient. However, we are making some progress. While the 2016 Plan omits mention of equity or justice, we have centered these concepts in the recommendations stemming from our more recent studies and we will integrate explicit consideration of equity in the priority actions of this 2022 Update and throughout development of all future climate strategies.*

Studies, Programs, Policies, and Legislation

Since 2016, Rhode Island has conducted over a dozen additional studies, gained six years of additional experience running programs, have enacted a number of important policies and passed a number of important laws. In this section, we review what we've done and what we've learned.

Key Studies Since 2016

Since 2016, the State has conducted a number of in-depth studies deepening our understanding of decarbonization activities and enabling actions. The following list contains major studies either directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning.

The following list of studies is not complete but is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy. This list does not include state plans in which stakeholders and agencies prioritize and plan investments in state infrastructure[42] nor does this list include retrospective evaluations of programs, though such evaluations are crucial to increasing the impacts of these programs. This list also omits studies conducted by federal agencies and non-governmental organizations that add to our understanding and depth of knowledge.

100% Renewable Electricity by 2030 (2020)

http://www.energy.ri.gov/100percent/

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2020, the Rhode Island Office of Energy Resources (OER) conducted an economic and energy market analysis, and developed policy and programmatic pathways, to meet this goal. *The Road to 100% Renewable Electricity by 2030 in Rhode Island* provides economic analysis of the key factors that will guide Rhode Island in the coming years as the state accelerates its adoption of carbon-free renewable resources.

The study considers available renewable energy technologies, including their feasibility, scalability, costs, generation patterns, market value, and local economic and employment impacts, as well as barriers that may hamper or slow their implementation. It identifies ways to leverage competition and market information to ensure reasonable ratepayer costs and manage energy price volatility, while taking advantage of economic development opportunities within the state. Utilizing this information, OER developed specific policy, programmatic, planning and equity-based actions that will support achieving the 100% renewable electricity goal.

Solar Siting Opportunities (2020)

http://www.energy.ri.gov/documents/renewable/Solar%20Siting%20Opportunities%20for%20Rhode%20Island.pdf

In an effort to assist with planning future solar photovoltaic (PV) development within the context of other land-use interests such as conservation, agriculture, and housing development, the Rhode Island Office of Energy Resources (OER) contracted Synapse Energy Economics to develop an estimate of the likely solar potential available within a number of solar siting categories. We conducted this statewide study using a granular bottom-up approach, primarily through the use of geospatial data and geographic information system (GIS) software.

Synapse examined and quantified solar potential for rooftop solar (including rooftops of residential single family, residential multifamily, commercial, industrial, municipal, and other building types); ground-mounted solar on landfills, gravel pits, brownfields, and commercial and industrial developed and undeveloped lots; and in parking lots. These categories were identified by OER as types of locations that could aid in policymakers' decisions for balancing future solar PV development with other land use interests such as conservation, farming/agriculture and housing development.

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[42] Such plans include the Long-Range Transportation Plan, State Transportation Improvement Program, Forest Action Plan, Comprehensive Outdoor Recreation Plan, State Energy Plan, RIPTA's Sustainable Fleet Transition Plan, or local comprehensive planning. We refer interested readers to the State Guide Plan developed and maintained by the Division of Statewide Planning for more information.

The report finds that in aggregate across all six categories analyzed, technical potential for solar is between 3,390 megawatts (MW) and 7,340 MW, or 13 to 30 times the amount of solar that is currently installed in Rhode Island. This translates into 5,560 gigawatt-hours (GWh) to 12,600 GWh of electricity able to be produced. Median estimated upfront prices for these categories range from about $3 to $5 per watt. If this entire technical potential were installed, we estimate that up to 7.65 million metric tons of carbon dioxide (MMTCO2) could be displaced, equal to about 70 percent of Rhode Island's total, current greenhouse gas emissions. However, the feasibility of this, especially in light of high costs, needs to be further examined.

Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs (2022)

Conceptual Framework: https://www.nrel.gov/docs/fy22osti/81960.pdf
Technical and Economic Analysis: https://www.nrel.gov/docs/fy22osti/80556.pdf

From 2019-2022, the Rhode Island Office of Energy Resources, National Grid, Rocky Mountain Institute, National Renewable Energy Lab, Lawrence Berkeley National Lab, and Clean Energy States Alliance partnered on a project supported by the Solar Energy Innovation Network. This 2022 report explores one integrated technical and process concept designed to manage interconnection costs and streamline interconnection timelines to support near-term renewable energy deployment. The report describes a new agreement between renewable energy developers and utilities, informed by a technical and economic analysis. The agreement defines the operational parameters for a renewable energy system, with the goal of reducing risk and cost to all parties. This work provides a foundation upon which states and utilities may build proof of concept.

Resilient Microgrids for Critical Services (2017)

http://www.energy.ri.gov/reports-publications/past-projects/resilient-microgrids-for-critical-services.php

The Rhode Island Office of Energy Resources commissioned the report Resilient Microgrids for Critical Services in 2017. In the wake of multi-day power outages due to severe weather events in recent years, OER sought consultant support for design of a program intended to enhance the energy assurance of critical infrastructure through deployment of distributed energy resources and other means. This effort draws from lessons learned in other states with similar programs. This report describes technologies, procurement strategies, and polices that can contribute to microgrid development.

Power Sector Transformation (2017)

http://www.energy.ri.gov/electric-gas/future-grid/

In November 2017, OER, along with the Division of Public Utilities and Carriers (DPUC) and Public Utilities Commission (PUC), issued a major report on how Rhode Island could develop a more dynamic regulatory framework to enable a cleaner, more affordable, and reliable energy system for the twenty-first century. Goals of transforming the power sector include controlling long-term costs of the electric system, giving customers more energy choices and information, and building a flexible grid to integrate more clean energy generation. This report describes recommendations for four workstreams: 1) utility business models, 2) grid connectivity and functionality, 3) distribution system planning, and 4) beneficial electrification. The recommendations in this report are based on significant stakeholder engagement, staff expertise, and consultation with national experts.

Docket 4600: Investigation into the Changing Electric Distribution System (2017)

http://www.ripuc.ri.gov/eventsactions/docket/4600page.html

From 2016-2017, the Public Utilities Commission investigated how a changing electric distribution system impacted their review of rate structures proposed in future proceedings. The resulting stakeholder report and order adopting the stakeholder report provide "a set of rate design principles and a benefit-cost framework to inform how rates could be set in a way to properly incent National Grid to meet state policies." Importantly, this benefit-cost framework includes societal costs and benefits: greenhouse gas externality costs, criteria air pollutant and other environmental externality costs, and conservation and community benefits. Consideration of these factors provided a basis for which regulators can incorporate climate impacts into their decisions for certain applications.

Heating Sector Transformation (2020)

http://www.energy.ri.gov/HST/

The 2020 Heating Sector Transformation report identified and analyzed the state's potential pathways to thermal decarbonization. It was the result of an Executive Order from July 2019 issued by former Governor Gina Raimondo. The study was led by the Office of Energy Resources (OER) and the Division of Public Utilities and Carriers (DPUC) and conducted by the Brattle Group.

The report identified several different decarbonization pathways, generally categorized into two types: electrification or decarbonized fuels. The findings suggest that several pathways exist that would enable RI to decarbonize the thermal sector by 2050, and also maintain similar overall energy expenses for households to those of present day. Due to a number of factors, including uncertainty around the future rate of technological development, the report recommended that none of the potential decarbonization pathways be foreclosed on, but rather a suite of thermal decarbonization efforts be pursued in the coming years. Work in the coming years should focus on education and laying the groundwork to support several decarbonization avenues.

Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island (2021)

http://www.energy.ri.gov/evplan/

In August 2021, the Rhode Island General Assembly passed bills H5031/S0994 directing the Department of Transportation (RIDOT), the Division of Motor Vehicles (DMV), and the Office of Energy Resources (OER) to "develop, no later than January 1, 2022, a plan for a statewide electric vehicle charging station infrastructure in order to make such electric vehicle charging stations more accessible to the public." In response, RIDOT, DMV, and OER, along with representatives from the Rhode Island Department of Environmental Management (RIDEM) and Rhode Island Department of Health (RIDOH) – collectively the Project Team – *developed Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island*.

The intent of this Strategic Policy Guide was threefold: First, the Project Team reviewed the status quo of electric vehicles and their charging infrastructure, as well as current and prior programming. The purpose of this review was to establish where Rhode Island is with vehicle electrification as we look ahead to 2022. Second, the Project Team distilled needs and recommendations heard during three months of public comment, three public listening sessions, and two dozen one-on-one meetings with agencies and external stakeholder organizations. The purpose of this report was to prioritize the most critical items to integrate into future policies and programs. Third, the Strategic Policy Guide will be a working document from which agencies – and stakeholders – can coalesce around priorities and coordinate action in the years to come.

Clean Transportation and Mobility Innovation Report (2021)

http://climatechange.ri.gov/documents/mwg-clean-trans-innovation-report.pdf

This 2021 report published by the Mobility Innovation Working Group provides a bold and ambitious vision for Rhode Island's transition to a cleaner and healthier transportation network. The scope of the report deals with short-and long-term trends that open opportunities for implementing new technologies and strategies to build a more equitable and environmentally responsible transportation system. The transportation sector represents the largest share of Rhode Island's greenhouse gas emissions. In order to meet a net-zero future, bold initiatives are needed to electrify this sector while also encouraging infrastructure development and community design

Rhode Island's uniquely small land area creates an opportunity to integrate and coordinate transportation and land use policy. The state's single public transit agency, single statewide planning organization, and single major utility have the ability to streamline the framework for GHG emissions reduction policies. Recommendations build off establishing Rhode Island as a national leader in transportation and climate commitments, unlocking economic opportunity and green job creation, while focusing on creating a healthier and more equitable environment for residents of our most overburdened and underserved communities.

Energy Efficiency Market Potential Study (2020)

https://rieermc.ri.gov/resources/

Commissioned in 2020 by the Energy Efficiency and Resource Management Council, this Market Potential Study covers the six-year period from January 1, 2021 to December 31, 2026 and estimates electricity, natural gas, oil, and propane energy savings; passive electric demand reduction savings and active demand response savings; and the costs and benefits associated with these savings.

Value of Forests (2019)

http://www.dem.ri.gov/programs/bnatres/forest/pdf/forest-value.pdf

This 2019 report discusses and identifies ways in which trees, plants, and vegetation are beneficial to Rhode Islanders and the Ocean State as a whole. The study uses data and visual depictions to convey the benefits and impacts of a healthy forest, good management practices, and engaged community members. Furthermore, the study frames areas for improvement and conservation growth with regards to air and water quality, climate change, human well-being, and wildlife. 56% of Rhode Island's land area is covered by vital forests and The Value of Rhode Island Forests focuses on how best to maintain, grow, and understand the state's vast forestry, open space, and conservation land. RIDEM developed this plan in conjunction with the US Forest Service and the Rhode Island Tree Council.

Resilient Rhody (2018) and Resilient Rhody 3-Year Impact Report (2021)

https://riib.org/solutions/initiatives/

To accelerate climate resilience actions and investments, former Governor Gina Raimondo signed an Executive Order on September 15, 2017 calling for the development of the state's first comprehensive climate preparedness strategy. Following nine months of collaborative work, Resilient Rhody was published and it lays the groundwork for collective action, involving state agencies, municipalities, and statewide business, academic, and nonprofit partners. The strategy responds to changing weather and environmental conditions in Rhode Island caused by climate change and proposes bold yet implementable actions to better prepare the state for these impacts. Building on the climate leadership of state government, municipalities, and organizations, Resilient Rhody leverages existing studies and reports to identify critical actions that move Rhode Island from planning to implementation.

Resilient Rhody identified priority actions the state could take to build statewide resilience, as well as a need to work collaboratively with and in support of municipalities across Rhode Island to build resilience at the local level. In response to this need, the Bank, in partnership with The Nature Conservancy, introduced the Municipal Resilience Program (MRP) in order to provide clearer pathways to implement the shared priorities of Resilient Rhody with participating municipalities. The purpose of the Municipal Resilience Program is to help Rhode Island municipalities deepen their understanding of climate risk and adaptation approaches, as well as to assist municipalities to prioritize and implement local resilience actions, effectively increasing climate resilience across Rhode Island and advancing Resilient Rhody. In November 2021, the Bank released the 'Resilient Rhody 3-Year Impact Report' detailing progress that has been made by state agency and municipal partners in turning the original 2018 Resilient Rhody report's recommendations into concrete actions including infrastructure upgrades, coordinated planning, and financing of resilience projects.

Climate Change and Health Resiliency (2015)

https://health.ri.gov/publications/reports/ClimateChangeAndHealthResiliency.pdf

This 2015 report by the Rhode Island Department of Health warrants mention because of its thorough review of climate's impacts on health. The report discusses implications of extreme heat and rising temperatures, air quality, extreme weather, water quality, marine bacteria, and vector-borne disease. Importantly, this report also discusses climate change's implications for mental health. The report provides some next steps for action which continue to be relevant to our recommendations today.

Carbon Pricing Study (2020)

http://www.energy.ri.gov/documents/carbonstudy/final-rhode-island-carbon-price-study-report.pdf

In response to a 2017 directive from the Rhode Island General Assembly, OER and RIDEM in consultation with the RIDOT, contracted with the Cadmus Group and Synapse Energy Economics to investigate potential state and regional carbon pricing policy options to support Rhode Island in achieving the requirements laid out in the 2014 Resilient Rhode Island Act. This report provides an impartial assessment of the implementation considerations and potential impacts of illustrative carbon pricing policies.

The report outlines several key findings: A carbon price at the levels analyzed in this study would not achieve Rhode Island's 2050 greenhouse gas (GHG) reduction targets alone. Determining how to use revenue generated by the carbon price is a chief policy design step. Equity needs to be a conscious choice in both process and ultimate policy design. A carbon price has a small impact on electric vehicle (EV) adoption. A carbon price contributes, in a limited fashion, to increasing the adoption of air source heat pumps (ASHPs). A carbon price will create shifts in Rhode Island's economy, but aggregate economic impacts are expected to be negligible. A carbon price would generally have a limited aggregate impact on households. Lastly, a wider geographic scope would lead to greater success.

Rhode Island Bicycle Mobility Plan (2020)

https://planning.ri.gov/sites/g/files/xkgbur826/files/documents/LRTP/Bicycle-Mobility-Plan.pdf

Approved in December 2020, Rhode Island's Bicycle Mobility Plan (BMP) is the first statewide initiative to expand the bicycle network strategically. The BMP takes a more detailed look at specific conditions, needs, and gaps surrounding bicycle infrastructure and operations in the State of Rhode Island and identifies supporting policies, strategies, and projects that will expand the network over the 20-year vision set out by the Long-Range Transportation Plan. The plan seeks to safely and efficiently connect people and places so that riding a bicycle in Rhode Island is safe and fun for all ages. It also serves as a guide to assist municipalities at developing bicycle infrastructure at the local level.

Rhode Island Transit Master Plan (2020)
www.transitforwardri.com

Also approved in December 2020, the Transit Master Plan (TMP) performs a comprehensive analysis on the condition, needs, and future solutions to the transit network and works within the same 20-year horizon as the Long-Range Transportation Plan and Bicycle Mobility Plan. The TMP sets out to achieve four major goals: make transit attractive and compelling, connect people to life's activities, grow the economy and improve quality of life, and ensure financial and environmental sustainability. The plan hopes to guide investments to provide transit riders with faster services in dedicated lanes, investments in stops and regional hubs, and increased transit frequency.

Clean Energy Industry Reports (2016-2021)
http://www.energy.ri.gov/cleanjobs/

The 2021 Clean Energy Industry Report is the seventh iteration in a series of reports conducted and written by BW Research Partnership, Inc. under commission by the Rhode Island Office of Energy Resources and the Renewable Energy Fund at Commerce RI. Findings in this report are based on data taken from comprehensive 2021 U.S. Energy and Employment Report (USEER). The 2021 USEER utilizes data from the Bureau of Labor Statistics Quarterly Census of Employment and Wages (BLS QCEW 2019 Q2) and Current Employment Statistics, as well as survey data. The survey was designed and implemented by BW Research Partnership. This series of reports provide crucial insight into trends in Rhode Island's clean energy workforce.

Select New Programs Since 2016
This section highlights some programs that have supported decarbonization strategies in Rhode Island, focusing on new programs since the *2016 Greenhouse Gas Emissions Reduction Plan* was released. The main takeaway from the programs described below is that we have gained a lot of experience with offering programs to support decarbonization. This experience should be leveraged to support progress toward our 2030 mandate and these programs provide an existing vehicle for deploying funding to support our climate goals.

This is not a comprehensive inventory of programs – to keep this section manageable, we exclude many impactful programs that began prior to 2016, are limited in term and funded by external grants, or are not administered directly by state agencies. We also omit many significant refinements to existing programs that have increased their impacts and benefited Rhode Islanders.

Expanding Energy Efficiency Programs
While National Grid (now RI Energy) has a long history of administering an energy efficiency program for its customers, Rhode Island's two municipal-owned utilities have made notable advances in their own energy efficiency programs. Since 2016, we can now say we have full statewide coverage to support energy efficiency.

Following an initial pilot program in 2015-2016, Block Island customers were offered an expanded energy efficiency pilot program called 'Block Island Saves' in 2016-2017. In 2021, Block Island Utility District launched a full-scale energy efficiency program for its customers.

Electric customers in Pascoag saw their long-running program substantially expanded beginning in 2019. The new program offers more incentives for more types of energy efficiency upgrades for both households and businesses.

Renewable Energy Fund

CommerceRI's Renewable Energy Fund (REF) provides grants for renewable energy projects. Since the program started in 2014, nearly 500 applicants received Renewable Energy Fund grants totaling $3.7 million for over 11 MW of grid-connected renewable energy.[43] Several notable program features have been added to the Renewable Energy Fund since 2016.

In 2017, the REF began incentivizing Community Renewables, including community solar. A community solar project is a large solar farm shared by more than one household. Its primary purpose is to allow members of a community the opportunity to share the benefits of solar power even if they cannot install solar panels on their roof or property.

In 2020, the REF began incentivizing the installation of solar projects located on brownfields. Brownfields are former industrial or commercial sites where future use is affected by environmental contamination and are often ideal locations for renewable energy projects. By incentivizing the installation of solar on already disturbed sites, this feature helps reduce pressures to develop open space, forests or farmland for solar projects.

In 2020, the REF began piloting an enhanced incentive for solar projects that are paired with battery energy storage systems. Energy storage can help match the timing of renewable electricity production with that electricity is consumed, which can reduce strain on our electric grid during critical times and provide other grid support. Energy storage can also provide backup power when the power is out.

Supply Chain Challenges

> *Supply Chain Shortages due to COVID-19 have had dramatic impacts on construction costs for clean energy systems. Spikes in steel prices, other raw materials, and transportation costs have led to higher costs and delays for renewable energy systems, electric transportation, and electric heat pumps. Rising costs and supply chain issues continue to create uncertainties in the clean energy industry, especially with respect to the reliability of future employment opportunities given the ongoing pandemic.*

Electric Transportation Programs

Since 2016, Rhode Island has offered several new programs to support electric transportation.[44] From 2016-2017, incentives for electric vehicles were available through a program called DRIVE. This program offered rebates up to $2,500, based upon vehicle battery capacity. Over 250 Rhode Island drivers received rebates, totaling the programs funding limit of $575,000. Electric vehicles using the DRIVE

[43] Data through 12/31/2021
[44] This section does include programs offered by third parties or federal agencies, but we recognize the importance of these programs.

incentive were purchased at 15 different car dealerships across Rhode Island, generating over $300,000 in sales tax revenue for the state.

From 2017 to 2019, the Office of Energy Resources supported the installation of electric vehicle charging infrastructure at public locations through the ChargeUp! program. This program provided applicants with incentives to support the purchase and installation of electric vehicle charging stations (Level 2 or higher) at publicly accessible locations. In addition, applicants that installed at least one charging station through this program could also qualify for incentives to support the purchase or lease of a new electric vehicle as part of their public sector fleet. ChargeUp! supported the installation of 49 dual charging stations and the purchase of 9 electric vehicles.

From 2019-2022, the Office of Energy Resources ran an incentive program for electric vehicle charging stations called Electrify RI, funding with $1.4 million from the Volkswagen Diesel Settlement[45]. Incentives varied from $10,000 to $40,000 based on the type of charging station (Level 2, or DCFC) and sector (workplaces, multi-unit dwellings, state and local government, and publicly accessible locations). As of November 30, 2022, Electrify RI has supported the installation of 70 Level II charging stations, and 23 DC Fast Chargers throughout Rhode Island. In 2022, further federal funding will be available to expand electric vehicle charging infrastructure.

In July 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) and e-Bike rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program. It works towards making EVs more affordable for more Rhode Islanders.

Following recommendations from the 2017 Power Sector Transformation report, National Grid began its Electric Transportation Initiative. This suite of programs includes a pilot to encourage charging at certain times of the day to reduce strain on the electric grid, an incentive program to offset some costs of installing electric vehicle charging stations, and technical assistance to support converting fleets from gas to electric.[46]

Incentives for Heat Pumps

Converting heating systems to electric heat pumps is a key strategy to reduce emissions from heating. Incentives for installing heat pumps are new since 2016. These incentives have been offered by utility energy efficiency programs and by the Office of Energy Resources leveraging auction proceeds from the Regional Greenhouse Gas Initiative (RGGI). Since 2016, incentives have supported hundreds of households – in 2021 alone, over 500 households were supported. In 2022, the General Assembly passed a budget article that allocated $25 million to the High-efficiency Heat Pump Program (HHPP) that will provide a broadened suite of heat pump incentives to Rhode Islanders. It is set to launch in early 2023.

Agricultural Energy Grant Program

The Rhode Island Department of Environmental Management and Office of Energy Resources partnered to offer an energy grant program specifically designed to support farmers. The Agricultural Energy Grant Program provides grant awards of up to $20,000 for eligible energy efficiency and renewable energy

[45] https://dem.ri.gov/environmental-protection-bureau/air-resources/mobile-sources/volkswagen-settlement
[46] The Electric Transportation Initiative also included a discount on demand charged for eligible customers installing fast charging; this discount is no longer offered.

projects at qualifying Rhode Island Farms. This funding helps local farmers "green" their operations and benefit from the related energy and cost savings through energy efficiency projects and by transitioning to renewable power. Funding for this program is made possible through the Regional Greenhouse Gas Initiative (RGGI). Since 2016, grants totaling over $894,000 have supported more than 50 projects.

Lead-by-Example

Signed in 2015, Executive Order 15-17 set forth specific goals for the State Administration to lead-by-example. Since then, the Office of Energy Resources has devoted staff resources to leading this body of work and has expanded support to other public entities. To tout progress being made, the Lead-by-Example Annual Awards recognize achievement of public sector entities in implementing clean energy projects.

Since 2016, several Master Price Agreements (MPAs) have been developed to streamline procurement processes for state agencies and other public entities. An MPA is a list of pre-qualified vendors from whom a procurer may solicit quotes. This purchasing mechanism expedites decarbonization by clearly defining proposal requisition processes and providing access to a pool of prequalified energy services vendors. MPA 508 includes vendors to develop and install turnkey energy efficiency projects. MPA 509 includes vendors to develop and install electric vehicle charging stations. MPA 553/CR 44[47] includes firms that can provide turnkey solar installation and maintenance services for public entities.

OER has also coordinated several competitive procurements of gas and electricity supply. These procurements, in addition to covering all State accounts, have also been made available to other public sector entities, such as quasi-state agencies and municipalities. By aggregating demand and leveraging economies of scale through a competitive process, OER and the Department of Administration aim to reduce energy supply costs and reduce energy price volatility for all participating public entities. The current electric contract will deliver approximately $2.3 million in bill savings in 2021 compared to the default utility price and the current gas contract will deliver approximately $2.1 million in bill savings in 2020 compared to the default utility price.

OER is now the central clearinghouse for all utility billing for State accounts. By collating and providing greater oversight over State agency utility bills, OER has been able to improve energy usage and cost forecasting, decrease payment errors, and analyze progress toward Lead by Example goals. Importantly, OER has been simultaneously working to increase public and inter-governmental transparency into these important data sets.

In February 2018, Rhode Island’s first voluntary Stretch Codes were made available to private and public building construction and renovation projects. The codes were developed with the assistance of subject matter experts and were vetted through a public comment process. Rhode Island’s Stretch Codes are meant to be used on a voluntary basis to guide the construction and/or renovation of buildings that use less energy, have less negative impact on the environment, and achieve higher levels of occupant health and comfort.

In 2021, the LED School Lighting Accelerator Pilot was launched to support the conversion of public-school facilities to LEDs in Central Falls and Providence. Public schools, particularly in economically challenged school districts, have not had the funding and technical expertise to implement many clean energy upgrades. By providing the technical, procurement, and financial support needed to implement these projects, OER is helping to improve the operations, efficiency and learning environment in public

[47] CR-44 is a Continuous Recruitment procurement list. Similar to an MPA, a CR is a list of pre-qualified vendors. In contrast to an MPA, a vendor may apply to be included on a CR at any time through an open enrollment process.

school facilities. After a successful pilot, OER scaled up efforts to support LED lighting projects in additional districts, expanding the reach of the program to 10 communities by the end of 2022.

Created in 2019, the Clean Energy Internship Program is designed to help provide internship opportunities in clean energy careers, ranging across sectors (e.g. energy efficiency, solar) and job types (e.g. direct construction, engineering, research). This programs pairs students with host companies from Rhode Island. Student interns can develop professional skills under the mentorship of an industry partner to combat real world problems in energy and the environment. The Clean Energy Summer Internship program approved five interns providing a reimbursement to four clean energy host companies that totaled $16,871.85 in calendar year 2021.

Municipal Resilience

Resilient Rhody identified priority actions the state could take to build statewide resilience, as well as a need to work collaboratively with and in support of municipalities across Rhode Island to build resilience at the local level. In response to this need, the Bank, in partnership with The Nature Conservancy, introduced the Municipal Resilience Program (MRP) in 2019 to provide clearer pathways to implement the shared priorities of Resilient Rhody with participating municipalities. The purpose of the MRP is to help Rhode Island municipalities deepen their understanding of climate risk and adaptation approaches, as well as to assist municipalities to prioritize and implement local resilience actions, effectively increasing climate resilience across Rhode Island and advancing Resilient Rhody.

As of 2022, 27 municipalities have participated in the Rhode Island Infrastructure Bank's program which includes a robust stakeholder engagement approach to resilience planning. MRP workshops have hosted over 600+ participants, including municipal staff and community leaders. 350+ potential resilience capital projects have been identified using this locally specialized approach.

As of 2022, 46 resilience projects have been funded through MRP Action Grants - a total of $7.5 million in assistance. 93% of MRP Action Grants have incorporated green infrastructure and/or nature-based solutions. $7 million was allocated to the MRP through the 2021 Beach, Clean Water, and Green Economy Bond, and another $16 million was allocated to the MRP through the 2022 Green Economy Bond. MRP workshops statewide have identified a need for local capacity building, as well as a need for regional approaches that can address resilience projects spanning municipal boundaries. Rhode Island Infrastructure Bank launched a pilot Regional Resilience Coordinator position at the Bank, within the MRP, to provide additional capacity for local resilience. The pilot position, a Regional Resilience Coordinator for Aquidneck Island, assists island municipalities to advance intra- and inter-municipal resilience efforts, and serves as a model for future Regional Resilience Coordinator positions at the Bank.

MRP municipalities have also expressed a need for increased design and engineering assistance, particularly for resilience projects implementing green infrastructure and nature-based solutions. In response, the Bank will launch a new initiative in 2023: '*Creating a Centralized Nature-Based Resilience Program for RI*.' This upcoming initiative, funded by the National Fish and Wildlife Foundation and conducted by the Rhode Island Infrastructure Bank in partnership with Narragansett Bay National Estuarine Research Reserve, University of Rhode Island Coastal Resources Center / Sea Grant, Save the Bay, and The Nature Conservancy, will assist MRP municipalities to advance resilience project ideas to construction ready designs.

Climate Change and Health Program

Since the 2015 Climate Change and Health Resiliency report, RIDOH has continued to support community resilience and adaptation efforts focusing on extreme heat, flooding, emergency preparedness, and sea level rise. Resilience building efforts with the Health Equity Zones have resulted in grants for urban greening and tree planting, community education and youth activities, and efforts to support senior living facilities, schools, and municipal cooling centers.

During the summer of 2020, RIDOH collaborated with the RIDEM Division of Forest Environment and American Forests to measure ambient air temperatures across several Rhode Island municipalities and neighborhoods. This project resulted in a set of maps that identifies urban heat islands and heat disparities during different times of the day. Areas where overnight temperatures stay high and where daytime temperatures can be up to 12 degrees hotter than others are considered priority areas for heat mitigation using tree planting and other urban greening techniques.

In 2021, the RIDOH Climate Change and Health Program conducted a needs assessment with a small group of stakeholders. This assessment showed that we need to continue collaborating across state agencies to deepen our connection with the community and drive change through inclusion of a diversity of community voices. The Climate Change and Health Program sees its role as supporting community engagement, educating the public and other agencies about risks to human health, and building resilience and social cohesion. Additional resources are needed to continue this work at a meaningful level while integrating it into 2021 Act on Climate goals.

Climate & Youth

Climate change has contributed to extreme weather events, air pollution, and rising temperatures. As the impacts of climate change become more severe, the fear of uncertainty in our future grows. Our youth population is already facing challenges caused by climate change. We need to prepare and educate our youth on how policies can be used to regulate and slow down the anthropogenic activities that are causing climate change. This will allow the future generation to gain skills that will help them determine the best ways to fight against climate change. When it comes to youth and climate it is also important to recognize that young people are active participants in climate action and provide a valuable perspective that deserves to be heard by decision-makers, as we will be leaving the Earth to them.

Climate change education is critical because the impacts that climate change is having on humans goes beyond our physical health. It can also affect our mental health, especially in our youth. For example, natural disasters related to climate change, such as hurricanes and wildfires, may lead to high levels of anxiety and trauma. Long-term impacts of climate change can cause fear of not knowing what the future of our environment will be, leaving our youth feeling helpless. To help ease the anxieties of climate change in our youth, we need to educate them on the importance of climate policies and what they can do personally to help.

It is important that we ensure our youths voices are heard. Through climate-youth workshops, young Rhode Islanders can learn about our current climate change policies as well as be given an opportunity to share their ideas on climate's impact on our youth. It is critical that we focus not only on meeting our climate mandates but also ensuring health, safety, and comfort of our youth community.

Policies and Legislation

The following list highlights some policies and legislation that showcase substantial commitments toward our climate goals. This list is not exhaustive, and every piece of policy and legislation matters. Interested readers should contact their local legislators to learn more about considerations in the General Assembly.

2021 Act on Climate

The 2021 Act on Climate sets statewide, economy-wide climate goals that are both mandatory and enforceable. The Act requires the state reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and reach net-zero emissions by 2050. The Act also requires the development of this update to the *2016 Greenhouse Gas Emissions Reduction Plan* in 2022 and a comprehensive climate strategy by 2025, to be updated every five years thereafter.

Critically, the Act deems addressing the impacts on climate change to be within the powers, duties, and obligations of all state departments, agencies, commissions, councils, and instrumentalities, including quasi-public agencies. The Act gives each agency the authority to promulgate rules and regulations necessary to meet the Act's greenhouse gas emissions reduction mandates.

COP26 (Signaling Promising Momentum) and COP27 (Loss & Damage Fund)

In November 2021, the United Nations Climate Change Conference (called COP26) was held in Glasgow, Scotland. Many first-hand accounts of this remarkable meeting were shared afterwards, including from Rhode Island State Senator Dawn Euer at the December meeting of Rhode Island's Executive Climate Change Coordinating Council held in Newport.

Bill Gates also shared his experiences and observations in a blog post. Mr. Gates noted three major areas of change that have happened since the last summit he attended in 2015; clean-energy innovation is higher on everyone's agenda, the private sector is now playing a major role alongside government agencies; and, there is much more public visibility and acceptance of climate adaptation.

The 27th Conference of the Parties (COP27) took place during the first two weeks of November 2022 in the Egyptian coastal city of Sharm el-Sheikh. More commonly referred to as COP27, this conference was touted as the "Africa COP" with a specific focus on implementation to help turn past pledges into real climate action. The conference closed on November 20th after all night negotiations. The highlight of the conference was an agreement to establish a "loss and damage" fund. The fund aims to provide financial assistance to nations most vulnerable to the adverse effects of climate change. However, key details, such as which countries will pay into the fund, have yet to be fully decided. While the creation of a "loss and damage" fund was historic, the lack of action on adaption and mitigation begs the question of whether the "loss and damage" fund will translate into action. Additionally, many countries did not bring updated nationally determined contributions to COP27 and therefore have not set more ambitious climate targets that are necessary to stay below the Paris Agreement goal of a 1.5°C. Finally, the most disappointing element of COP27 was the failure to commit to decisively phase out the use of fossil fuels.

Appliance Energy Efficiency Standards

In 2021, the General Assembly updated Rhode Island's energy and water efficiency standards for a number of common appliances.[48] The legislation sets minimum efficiency standards for 15 household and commercial products which will save energy, save money, and reduce greenhouse gas emissions. From 2023 to 2035, these standards are expected to reduce emissions by 256,000 metric tons.

Transportation and Climate Initiative

The Rhode Island Department of Environmental Management led Rhode Island's participation in the Transportation and Climate Initiative (TCI), a regional cap-and-invest policy proposal for the transportation sector. In December 2021, neighboring states Connecticut and Massachusetts paused their participation in this effort. As this effort depends upon the involvement of at least three jurisdictions, Rhode Island cannot move forward with TCI at this time. However, key insights about priorities for program design and revenue investment should be incorporated into future policies and programs.

Conversations about Solar Siting

Since 2016, increasing deployment of large solar PV systems in forested areas has raised concerns from stakeholders and the public about finding the right balance of renewable energy development amidst policy objectives like decarbonization and land conservation. These local conversations have informed studies (e.g. the Solar Siting Opportunities study, Value of Forests report), program design (e.g. REF Brownfields Program), and policies (e.g. municipal solar ordinances). These conversations should continue to inform our climate strategies, particularly related to decarbonizing our electric sector and preserving environmental benefits of Rhode Island's forests.

Increasing Biofuels

In 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil. The new law requires home heating oil to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025 and 50% in 2030. Biodiesel is a fuel made from plant or animal products or waste. It must meet standards and is blended with petroleum heating oil to burn cleaner and reduce greenhouse gas emissions. Rhode Island had previously required heating oil to be sold as a mix that contains 5 percent biodiesel, phased in between 2014 and 2017.

Offshore Wind

In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. This new project is expected to reduce Rhode Island's greenhouse gas emissions by 11 MMTCO2e, in addition to providing substantial local economic benefits including more than 800 direct construction jobs, 50 permanent jobs, and hundreds more jobs supported indirectly as the region's burgeoning offshore wind industry takes off.

Land and Forest Conservation

In 2016, the RI General Assembly amended the laws of the state as they relate to the conservation and preservation restrictions on real property (RIGL §34-39-5). The amendment makes it more difficult remove land conservation restrictions. The result has been stronger land protection laws in Rhode Island.

Forests provide invaluable ecosystem services like carbon sequestration and storage that are essential to meeting the state's climate change goals. In recognition of this natural asset, the Rhode Island General

[48] RIGL 39-27.1 Appliance and Equipment Energy and Water Efficiency Standards Act of 2021

Assembly passed the Forest Conservation Act in July 2021 (RIGL §2-27). The Act establishes a Forest Conservation Commission (FCC) to inventory the state's forestland, develop stronger tools and incentives for forest conservation, expand urban and community forestry, and grow the state's forest products industry. Led by RIDEM, the Forest Conservation Commission has been meeting regularly since mid-2022.

Pressures on Land Conservation Efforts

Land conservation efforts are significantly impacted by real estate market dynamics. Rhode Island's housing market has seen an unprecedented increase in value over the past several years. However, higher than ever development costs (i.e., roads, utilities, and home construction) have led to uneven expectations for the value of large land parcels, often leaving state land protection programs unable to match private market offers. Similarly, pressure for kilowatts of solar (renewable) energy has resulted a in large tracts of undeveloped property being converted to fields of solar panels. Finding the right balance between solar development and the need to protect working farms and forest land continues to be the subject of much discussion at the local level and in the General Assembly. Siting guidance and incentives that push solar development away from large forested and agricultural parcels can help to protect Rhode Island's remaining open space.

It is an ongoing challenge to protect interconnected land areas of sufficient size to support wildlife, biodiversity, and ecosystem services for future Rhode Island generations. Large, interconnected conservation lands are particularly important as a strategy for adapting to climate change because the distribution of animals and plants are likely to shift and continue shifting as temperatures, rainfall and the timing of seasons continue to morph over coming decades. Ensuring the state can be ready to match available funding with the opportunity to protect such critical land resources should be a priority resilience measure.

Rhode Island's 400 miles of coastline is particularly vulnerable to episodic storms, erosion, coastal flooding, inundation and storm surge. The National Oceanic and Atmospheric Administration's February 2022 report 'Global and Regional Sea Level Rise Scenarios for the United States' indicates that relative sea level along the contiguous US coastline is expected to rise on average as much over the next 30 years as it has over the last 100 years. Land conservation efforts that accommodate and proactively target areas to allow for the inland movement of coastal habitat, such as wetland migration, are increasingly being considered to help maintain natural storm surge buffers, wildlife habitat, wetland-dependent human activities, water filtration, and other ecosystem services coastal wetlands provide.

2021 Beach, Clean Water, and Green Economy Bond & 2022 Green Bond

The 2021 Beach, Clean Water, and Green Economy Bond dedicated $7 million to the Municipal Resilience Program matching grants to municipalities to restore and/or improve the resiliency of infrastructure, vulnerable coastal habitats, river and stream floodplains, and watersheds. The Bond passed with 78.3% support, allowing the Municipal Resilience program funds to further advance community resilience to the impacts of climate change.

In the pilot years of the Municipal Resilience Program, limited MRP Action Grant funds meant that the Bank could only offer Action Grants to municipalities who had completed their MRP workshop in the current award year. With the support of this State Green Bond, the Bank has been able to expand the call for MRP Action Grant proposals, allowing any community who completed a Municipal Resilience Program workshop in any year access to MRP Action Grant funds annually. With a successfully widened call for MRP Action Grant proposals in fall of 2021, the Bank seeks to continue offering annual MRP Action Grants to all MRP municipalities each year.

2022 saw the passage of the 2022 Green Bond which infused an additional $16 million into the Municipal Resilience Program. This has greatly increased the capacity of the Bank to support resilience priorities identified by a majority of communities across Rhode Island.

Progress on 2016 Pathways

The *2016 Greenhouse Gas Emissions Reduction Plan* organized its emissions mitigation strategies as a set of pathways under three overarching objectives: build on state success, enable markets and communities, and leverage regional collaboration. We refer the reader to the 2016 Plan for the full description of each of these pathways. Here, we summarize the progress since 2016 and comment on the progress we still need to make. For additional detail on specific items since 2016, we refer readers to the other sections within this chapter.

Build on State Success

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that “Rhode Island has existing policies and proven models to address nearly all mitigation options, creating a strong foundation the State can build upon to reach our goals.” Since 2016, Rhode Island has continued to be a leader in our climate efforts.

Energy Efficiency

Rhode Island has continued to invest in its energy efficiency programs. In 2021, the General Assembly extended the statutory obligation to offer energy efficiency through 2029.[49] Programs have also been initiated and enhanced for customers of Pascoag Utility District and Block Island Utility District.

One notable achievement of these energy efficiency programs is their influence on transforming the lighting market. Programs in previous years emphasized incentives that reduced the customer cost of energy efficient lighting, a very cost-effective low hanging fruit to reduce energy use. Thanks to these incentives and appliance efficiency standards, energy efficient LEDs are now the prominent type of lighting technology, rendering utility incentives for LEDs unnecessary in most applications. Today’s energy efficiency programs are in the transition to incentivize other efficient technologies like building automation, high-efficiency HVAC, and weatherization.

The 2016 Plan recommends “policymakers could address a critical gap in existing programs – limited energy efficiency services for delivered fuels (heating oil and propane) customers, a group comprising over one-third of all heating customers. A sustainable funding and/or financing solution is needed for these users to enjoy full and equal access to energy efficiency programs.” Rhode Island continues to lack this sustainable funding solution for customers relying on delivered fuels for heating.[50] Short-term, limited funding has been proposed as a stop-gap solution, but we must come up with a permanent funding stream to achieve the level of heating decarbonization needed to meet our longer-term climate mandates.

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[49] Least-Cost Procurement Statute

[50] Some funding is available to incentivize some efficiency measures for electric customers who heat with delivered fuels (e.g. weatherization).

The 2016 Plan recommends screening additional appliances to see whether enacting or updating energy efficiency standards may be warranted – in 2021, Rhode Island did indeed enact updated appliance efficiency standards.[51]

Lastly, the 2016 Plan recommends making energy costs of purchases visible to consumers including through building energy disclosure and labeling. While discussions have occurred, no such statewide policy has been enacted.

Vehicle Miles Traveled (VMT) Reductions

The 2016 Plan notes a number of considerations that may encourage the reduction of vehicle miles traveled, including increasing transit and mode share ridership targets, integrating transportation and land use planning, using price signals to discourage solo driving, and investing in alternative modes of mobility.

In 2019, Rhode Island launched the Mobility Innovation Working Group, a 26-member panel of experts comprised of equal participation from the private and non-profit sectors as well as key state agency representatives. The two-year effort culminated in a thorough strategy for improving mobility broadly, including additional thinking around reducing vehicle miles traveled. To date, there has been no concerted action to expressly reduce vehicle miles traveled. On the contrary, all efforts have been based on strategies to improve the relative attractiveness (e.g. convenience, cost savings) of alternative forms of mobility (e.g. transit, biking, walking) and better connect residents with destinations (e.g. state and local comprehensive plans).

In 2021, the Rhode Island Turnpike and Bridge Authority completed installation of all-electronic tolling at their Jamestown Plaza serving drivers crossing the Newport Pell Bridge. While not explicitly reducing vehicle miles traveled, this project does reduce idling and congestion, which reduces localized air pollution and emissions.

Clean Energy

The 2016 Plan recommends aligning "in-state renewable energy policy and deployment targets to be consistent with the broader goal of a 99% clean regional grid by 2050. As part of this consideration, policymakers would need to weigh the comparative costs and benefits of different pathways (e.g., local versus regional renewables, the role of different technologies, and the need for incremental distribution or transmission investments)." Rhode Island's 100% Renewable Electricity by 2030 report analyzes the trade-offs between various technology pathways to meet all of Rhode Island's electricity demand with renewable energy resources. Among other important insights, this report recommends enacting an accounting mechanism to ensure Rhode Island either generates or offsets all its electricity consumption with renewable energy resources.

Electric Heat

The *2016 Plan* noted the importance of transitioning to energy efficient electric heat, and the 2021 Act on Climate's stronger emissions mandates will necessitate this strategy even more. To offset costs of transitioning to efficient electric heating, the *2016 Plan* suggests using existing energy efficiency programs which would require "further policy guidance is needed to allow electrification of heating to fully qualify as an activity under the State's energy efficiency program or another energy program." Regardless of programmatic avenue to deploy funding and assistance, sustainable funding is needed.

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[51] RIGL 39-27.1 Appliance and Equipment Energy and Water Efficiency Standards Act of 2021

While there is a long-term funding source identified for upgrading inefficient electric heating systems (e.g. electric resistance) to efficient electric heating (e.g. heat pumps), this is not the case for supporting customers who would like to switch fuels. We have since employed short-term and limited funding sources as a stop gap measure to support fuel switching. Rhode Island has not yet identified a long-term source of funding that can support energy efficient heating electrification, particularly for customers who currently rely on delivered fuels, within our current statutory framework.

Biofuel Heat

In line with recommendations from the *2016 Plan* to increase the existing statewide bioblend standard, the General Assembly updated the Biodiesel Heating Oil Act in 2021. The strengthened Act now requires all home heating oil sold in Rhode Island to be 10% biodiesel or renewable hydrocarbon diesel in 2023, 20% in 2025, and 50% in 2030.

Electric Vehicles

The *2016 Plan* recommends “further initiatives to incentivize the adoption of electric vehicles and charging infrastructure would be needed to achieve the aggressive market penetration levels necessary to meet long-term GHG reduction targets.” Accordingly, Rhode Island has deployed several incentive and assistance programs to support electric vehicle purchases and installation of charging infrastructure, with significant incentive programs and funding becoming available in 2022.

In line with recommendations, the Rhode Island Public Transit Authority is working to convert its entire fleet to electric or zero-emissions buses by developing an action plan and the Department of Transportation is conducting a study to understand implications for gas tax revenues and resulting policy considerations to ensure sustainable funding for our transportation infrastructure. These commitments, along with many others by all state agencies represented on the Executive Climate Change Coordinating Council, are described in the report Electrifying Transportation.

The *2016 Plan* also recommends “future planning for the state’s passenger and freight rail transportation system could also evaluate electrification as a strategy aligned with long-term greenhouse gas reduction targets.” Electrification continues to be discussed and is considered in Transit Forward 2040, a collaboration between the Rhode Island Public Transit Authority, the Rhode Island Department of Transportation, and the Rhode Island Division of Statewide Planning.

Rhode Island has previously adopted California’s emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California’s standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles. Rhode Island should continue to adopt new rules, including California’s Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers, as well as the Advanced Clean Cars II regulation.

Transportation Biofuels

The *2016 Plan* suggests “Rhode Island could explore the feasibility of establishing a statewide bioblend standard” similar to bioblending for heating oil. Such a standard has not been enacted to date.

Land Use Conservation

The *2016 Plan* suggests considering “adoption of a ‘no net-loss of forests’ policy.” While such a policy has not be enacted per se, recent policies have strengthened land and forest conservation (RIGL §34-39-5 and RIGL §2-27). Renewable energy programs have also been developed to nudge renewable energy development away from forested areas and onto previously disturbed sites.

Natural Gas Leaks

The *2016 Plan* recommends "continuation of National Grid's gas infrastructure repair and replacement program to address fugitive methane leaks in the state's gas distribution system." Indeed, this work has continued in collaboration with the Division of Public Utilities and Carriers and under the regulatory oversight of the Public Utilities Commission.[52] Approximately 500 miles of leak prone pipe has been replaced since 2016 –which reduces leaks from the pipeline gas system. However, leak prone pipe replacement may actually be counterproductive to meeting the Act on Climate, since pipes that are replaced have a 50–100-year lifespan. This topic will likely be analyzed the Public Utility Commission's upcoming Future of Gas docket.

Energy Storage

The *2016 Plan* recommends "pursuit of policies to promote energy storage, which can provide many types of system benefits, including integrating clean energy resources in a more cost-effective manner." Since 2016, two key programs have been deployed to encourage energy storage: payment for performance of energy storage systems during demand response events and incremental incentives for solar PV systems paired with energy storage. The report 100% Renewable Electricity by 2030 echoes the recommendation to build out a strategic role for energy storage as we increase renewable energy on our regional grid; this work has not yet begun. In addition to electric energy storage, there are thermal storage options that can help decarbonize the thermal sector. These have not yet been extensively explored, but should evaluated in the coming years.

Other

This section outlines three 'other' pathways described in the *2016 Greenhouse Gas Emissions Reduction Plan*. In addition to the updates below, in 2021, RIDEM also enacted a new Air Pollution Control Regulation to prohibit manufacturers from selling products (air conditioning and refrigeration equipment, aerosol propellants, and foam) that contain a certain particularly potent greenhouse gas.[53]

Battery Storage in Pascoag

The Pascoag Utility District (PUD) unveiled a new 3MW/9MWh stand-alone battery storage installation in August of 2022, which will provide needed grid-reliability and peak load reductions for the utility's 5,000 customers. This battery project, alongside a needed substation upgrade, helped PUD avoid nearly $12 million dollars in infrastructure investment that would have otherwise been required to continue reliably serving their customers during peak-load conditions in the summer months.

Through an innovative and collaborative partnership with the Office of Energy Resources, the Rhode Island Infrastructure Bank, and Agilitas Energy, PUD was able to provide the reliability and load management it needed, at a fraction of the cost to its customers. The implementation of this battery is a successful example of implementing a non-wires alternative to improve reliability at a lower cost.

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[52] Plans for identifying and prioritizing the replacement of 'leak-prone pipe' are proposed in annual Infrastructure, Safety, and Reliability Plans. The most recent plan is included in Docket 5210.

[53] Part 53 of the Air Pollution Control Regulation, "Prohibition of Hydrofluorocarbons in Specific End Uses" (250-RICR-120-05-53) prohibits manufacturers from selling products that contain high global warming potential hydrofluorocarbons.

A first of its kind project in Rhode Island, this stand-alone battery demonstrates the viability of storage technologies in not only delivering value for utility customers but also supporting the State's Act on Climate mandates to reduce GHG emissions. Using batteries to store energy and dispatch it later at times of peak demand helps balance supply and demand. It also supports the transition to clean energy by allowing better integration of the increasing amount of renewable energy coming onto the electric grid.

Solid Waste

The *2016 Plan* recommends we put in place "strategies to reduce methane emissions from the Central Landfill." The RI Resource Recovery Corporation (RIRRC) continues to maintain a landfill gas (LFG) recovery system at the Central Landfill. LFG, which contains methane, is captured, converted, and used as a renewable energy resource. Using LFG helps to reduce odors and prevents methane from migrating into the atmosphere and directly contributing to climate change. Rhode Island's Central Landfill has one of the largest methane-to-energy plants in the country.

In 2015, RIRRC completed a waste characterization study that highlighted a significant opportunity to extend the life of its Central Landfill by further diverting organics from the municipal residential waste stream. Anaerobic decomposition of organic materials in landfills produces methane, a greenhouse gas with global warming potential many times higher than carbon dioxide. In 2018, RIRRC's Long Term Solid Waste Alternatives Study subsequently identified several means for processing this material. Then, in 2019, RIRRC identified 13 potentially viable collection scenarios that could be pursued for the technologies short-listed in the 2018 Alternatives Study. Recognizing that collection costs are a significant consideration of overall program delivery, RIRRC issued a request for proposals in 2020 to better understand the collection scenarios for organics that could be pursued in Rhode Island and what their associated costs may be – results of this analysis are expected in 2022. The co-benefit of reducing organics in the Central Landfill as a means to extend the life of the Central Landfill will be reduced methane emissions.

Enable Markets and Communities

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that "Rhode Island's best resources are our people and communities – with the right support, we can remove barriers to clean energy market growth, consumer education and engagement, partnership of utilities, and public sector leadership." This strategy of partnership and collaboration has not only been foundational for Rhode Island's leadership but has improved since 2016.

Grow Clean Economy Jobs

The *2016 Plan* provide three recommendations for state policymakers: "fostering nascent local clean energy industries, supporting innovation in clean energy, providing workforce training, and assisting incumbent fossil fuel industries (e.g., the delivered fuels industry) and disadvantaged communities with resources to excel in the burgeoning clean energy marketplace."

We point readers to the Office of Energy Resources annual Clean Energy Industry Report for more details about job growth and industry trends but note a few key items here. First, Rhode Island is working hard to position itself as a hub for the domestic offshore wind supply chain. For example, the 2019 contract for the 400 MW Revolution Wind offshore wind project includes $4.5 million in investments for Rhode Island's ports and offshore wind workforce.[54] Second, Rhode Island continues to support the local solar industry through programs that incentivize solar (e.g. RE Growth Program, Renewable Energy Fund) and partnerships for workforce development (e.g. Clean Energy Internship Program). Third, in 2022 the Department of Labor and Training is beginning an industry convening to assess workforce development needs for increasing consumer adoption of electric transportation (to launch in 2023). Fourth, the High-efficiency Heat Pump Program (HHPP) includes supporting workforce development as a key component.

Further strategic analysis needs to be conducted to recommend specific action items needed to support a just transition with living wages as part of the development of the *2025 Climate Strategy*, as required by the 2021 Act on Climate.

Empower Citizens and Communities

The *2016 Plan* lists barriers to consumer adoption of decarbonized technologies: "low customer awareness and confidence in previously unfamiliar products; access to and availability of financing solutions; soft costs related to permitting and regulatory hurdles; technical assistance for municipalities to implement solutions." These barriers are still present, but some work has attempted to mitigate them. This work includes consumer education and outreach campaigns (e.g. via Ocean State Clean Cities Coalition, via the Energy Efficiency and Resources Management Council), financing through energy efficiency programs and the Rhode Island Infrastructure Bank (e.g. HEAT Loan, on-bill repayment, Efficient Buildings Fund), and technical support for municipalities (e.g. via the Municipal Resilience Program, via OER's Shared Energy Manager pilot program). However, gaps remain and barriers are still present, which necessitates continued work to empower citizens and communities, and particularly low-income and vulnerable communities.

Foster a More Dynamic Regulatory Model

The *2016 Plan* states "state policymakers and utility regulators will continue initial efforts already underway to consider thoughtful changes to utility planning, business models, performance incentives, and rate design in order to enable a transition to the future grid that values, integrates, and plans for growth in clean energy and carbon-free resources, while maintaining a safe and reliable electric system." This statement alluded to the Power Sector Transformation initiative, which resulted in a stakeholder

[54] Press Release from April 2019

report in 2017. Resulting recommendations led to National Grid's programs related to electric transportation and proposals for both modernizing our electric grid and deploying advanced metering infrastructure. While these two proposals were filed in 2021, they were on hold while other regulatory proceedings were being resolved. In November 2022 Rhode Island Energy filed their Advanced Metering Functionality (AMF) Business Case to the Public Utilities Commission.[55] The Power Sector Transformation report also includes a number of recommendations that should continue to be considered.

Lead-by-Example

The *2016 Plan* advocates for the "state government to serve as an early adopter to demonstrate the benefits of greenhouse gas mitigation and clean energy solutions." In accordance with this recommendation, the Office of Energy Resources has supported state agencies across government leading by example with reducing energy use and cost, deploying renewable energy systems, transitioning fleets to electric, and installing electric vehicle charging infrastructure, among other accomplishments. These efforts to date will save Rhode Island nearly $100 million in energy costs over the lifetime of projects implemented.[56]

The *2016 Plan* extends leading by example to municipalities and communities: "at the local level, cities and towns can play an important role in achieving state greenhouse gas targets by integrating mitigation into community planning efforts, setting their own reduction goals, investing in clean energy projects, and directly engaging with diverse community voices." Programs like the Municipal Resilience Program and the Shared Energy Manager pilot program have supported these local efforts. Localities have also demonstrated their leadership in climate planning and community engagement. For example, the City of Providence has been widely recognized for their 2019 Climate Justice Plan and applauded for process of co-development between their Office of Sustainability and the Racial and Environmental Justice Committee of Providence.

Leverage Regional Collaboration

The *2016 Greenhouse Gas Emissions Reduction Plan* noted that "Rhode Island has a fruitful history of working cooperatively with neighbors to seek scalable, cost-effective solutions to mutual challenges; climate change mitigation is one such area that is ripe for strong regional partnerships." This strategy of regional collaboration has continued since 2016.

Regional Greenhouse Gas Initiative (RGGI)

The *2016 Plan* advocates for Rhode Island's continued participation in the Regional Greenhouse Gas Initiative (RGGI) and recommends advocating for program design elements that align RGGI emissions reductions with state climate mandates. Rhode Island has continued to be an active participant in RGGI since 2016. A program review is currently underway throughout 2021-2023, which will inform RGGI program design for future years.[57]

Transportation and Climate Initiative (TCI)

In accordance with *2016 Plan* recommendations to continue participation in the Transportation and Climate Initiative (TCI), Rhode Island continued to pursue TCI and consider legislation through 2021. However, in December 2021, neighboring states Connecticut and Massachusetts paused their participation in this effort. As this effort depends upon the involvement of at least three jurisdictions,

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[55] https://ripuc.ri.gov/Docket-22-49-EL
[56] Lead-by-Example 2020 Annual Report
[57] For more information about the RGGI Program Review and for opportunities to participate, visit https://www.rggi.org/.

Rhode Island cannot move forward with TCI at this time. However, key insights about priorities for program design and revenue investment should be considered in future policies and programs, and Rhode Island should leverage regional partnerships as opportunities arise.

New England Governors/Eastern Canadian Premiers

The *2016 Plan* supports Rhode Island's continued engagement with the New England Governors/Eastern Canadian Premiers (NEG/ECP). In 2018, NEG/ECP's Climate Change Steering Committee submitted the 2017 Update of the Regional Climate Change Action Plan and is currently working to execute this new report through various committees. Currently, there is a low level of activity in this regional organization.

Other Regional Work

The *2016 Plan* offers additional ideas for regional collaboration, including through renewable energy procurements and carbon pricing. Doing so is also a recommendation of the 100% Renewable Electricity by 2030 report. Regarding the *2016 Plan's* specific suggestions, Rhode Island leveraged a procurement by Massachusetts to contract for the 400 MW Revolution Wind offshore wind farm, and we conducted a study to examine the impacts of carbon pricing in 2020.

Also of note is a vision statement submitted in 2020 by the New England States Committee on Electricity (NESCOE, of which Rhode Island is a member) to ISO-NE, the organization that operates and maintains our region's transmission system. The NESCOE vision statement lays out three recommendations: First, wholesale markets need to be redesigned such that state-procured renewable energy systems are accounted for and properly valued. Second, transmission planning needs to account for substantial long-term deployment of renewable energy resources to meet states' decarbonization goals. Third, ISO-NE's governance needs to better reflect states voices and improve opportunities for public participation. Through NESCOE, New England states continue to work collaboratively to improve our regional transmission system.

In relation to transportation emissions: recognizing the urgent need for action, a diverse coalition of jurisdictions across the United States and Canada has committed, through the Multi-State Medium- and Heavy-Duty Zero Emission Vehicle (ZEV) Memorandum of Understanding (MOU), to work to reduce greenhouse gas emissions and harmful air pollution by accelerating the market for zero-emission trucks, vans, and buses. To achieve a timely transition and ensure near-term progress, the participating jurisdictions committed to strive to make at least 30 percent of sales of new medium- and heavy-duty vehicles ZEVs by 2030, and 100 percent of sales ZEVs by no later than 2050.

To translate commitment into action, the MOU directed the participating jurisdictions to develop a Multi-State Medium-and-Heavy-Duty (MHD) ZEV Action Plan to recommend policy options to foster a self-sustaining market. Released in July 2022, the Action Plan includes more than 65 recommendations for state policymakers to support the rapid, equitable, and widespread electrification of MHD ZEVs.

Meeting our 2030 Mandate

This section identifies recommendations for discrete priority actions by sector. Whereas the *2016 Greenhouse Gas Emissions Reduction Plan* offered "a broad framework to achieve the Resilient Rhode Island greenhouse gas reduction targets," this *2022 Update* recommends more granular actions needed in the short-term in order for Rhode Island to get on track to meet our 2030 emissions reduction mandate set forth by the 2021 Act on Climate. These priority actions are informed by all of our progress since 2016 – including studies, policies, and experience gained – as well as by stakeholder input.

The priority actions presented here are not comprehensive. We choose to focus on coordinated systems-level interventions that will either ensure or enable we meet our 2030 mandate. Instead of prescribing specifics for each action, we discuss the nuances of select factors that may be refined in order to advance policy co-objectives. Our intent is to elucidate the tradeoffs of certain refinements such that legislators, policy makers, and stakeholders can make decisions with the best understanding of impacts across the policy landscape.

In focusing on systems-level interventions, we de-emphasize priorities for individual action. This is not intended to downscale the importance of our individual decisions within our collective impact. Individual choices to reduce the greenhouse gas emissions within our control is fundamental and necessary for meeting Rhode Island's climate mandates. Indeed, we want to empower and encourage all Rhode Island households and businesses to reduce their own greenhouse gas emissions and prepare for impacts of a changing climate. Public administrations should lead by example here.

We also choose to focus on actions needed within the near future, when Rhode Island's comprehensive climate strategy is due and programs launching now will begin to take hold. The *2025 Climate Strategy* will include additional short-term and long-term actions to ensure Rhode Island meets is climate mandates through 2050.

Please also note that these actions have been restructured relative to the pathways identified in the *2016 Greenhouse Gas Emissions Reduction Plan.* This restructuring is intended to better align our strategic framework with how we think about our emissions inventory and the portfolio of analyses conducted since 2016. However, the pathways described in the *2016 Greenhouse Gas Emissions Reduction Plan's* broad framework comprise the foundation for the following short-term strategy.

Customized Emission Modeling Scenario for the 2022 Update

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with RMI and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by Acadia Center utilizing the *Energy Policy Simulator* (EPS) developed by Energy Innovation and RMI. By modeling a short list of key policy scenarios as outlined below, it is projected that Rhode Island slightly misses the Act on Climate's 2030 reduction mandate of 45% by 0.5 $MMTCO_2e$. To put this in perspective, the emissions in 2030 are projected by the EPS to be approximately 7.39$MMTCO_2e$, as compared to the 1990 baseline of 12.48 $MMTCO_2e$.

The EPS created a '2030 Climate Plan' scenario for Rhode Island using a number of realistic, actionable policies the state could adopt in the next decade.

Transportation

The EPS created a '2030 Climate Plan' for Rhode Island using various transportation policies the state is likely to adopt in the next decade. Clean transportation-related policies provide the greatest greenhouse gas emissions reductions. The following transportation policies help Rhode Island move towards the Act on Climate's 2030 GHG emissions reduction mandate of 45% below 1990 levels.

1. **Increase Adoption of Electric Passenger Vehicles**

   - Rhode Island can adopt California's *Advanced Clean Cars II* regulation as a Section 177 state. *(See Transportation Priority Actions for definition of a Section 177 state).*
   - If Rhode Island adopted *Advanced Clean Cars II*, **68% of all new passenger vehicles sold** in the state would be electric in 2030.
   - Adoption of the *Advanced Clean Cars II* helps Rhode Island **avoid approximately 0.29 MMTCO$_2$e emitted** in 2030.
   - Of the clean transportation-related policies, an estimated 88.5% of emissions reductions are attributed to switching to electric passenger vehicles.
   - In addition, an estimated 10.2% of all GHG emissions reductions modeled in the EPS are attributed to adopting more electric passenger vehicles.

2. **Increase Adoption of Electric Trucks & Buses**

   - Rhode Island can also adopt California's *Advanced Clean Truck* and *Medium-and-Heavy-Duty Omnibus* regulation to decarbonize large trucks and buses.
   - If Rhode Island adopted these regulations, **36% of all large trucks and buses sold** in the state would be electric in 2030.
   - Adoption of more electric trucks and buses helps Rhode Island **avoid approximately 0.04 MMTCO$_2$e emitted** in 2030.
   - Of the clean transportation-related policies, 11% of emissions reductions are attributed to switching to electric heavy-duty trucks and buses.
   - Also, 1.3% of all GHG emissions reductions modeled in the EPS are attributed to increased adoption of electric trucks and buses.

3. **Increase Decarbonization of RIPTA's Bus Fleet**

   - Another policy to reduce transportation-related greenhouse gas emissions is RIPTA's Zero Emissions Fleet Transition Program.
   - The EPS modeled the emissions reductions if **electric buses account for 17.7% of total miles travelled by the RIPTA bus fleet** in 2030.
   - An estimated **0.0004 MMTCO$_2$e** of GHG emissions would be avoided in 2030 with RIPTA's Zero Emissions Fleet Transition Program.
   - Of the clean transportation-related policies, 0.1% of all transportation emissions reductions are attributed to RIPTA's Zero Emissions Fleet Transition Program.
   - Additionally, 0.01% of all GHG emissions reductions modeled are attributed to the increased decarbonization of RIPTA's bus fleet.

4. **Expand RIPTA Ridership to Reduce Light Duty VMT**

   - Another powerful policy to reduce GHG emissions is known as "mode shifting".
   - Under this scenario, the EPS modeled the emissions reductions of a **4.8% reduction in vehicle miles travelled by single occupancy vehicles** below 2020 levels by 2030.

- Mode shifting reduces vehicle miles traveled (VMT), which takes more vehicles off the road and reduces traffic congestion.
- Through this scenario, Rhode Island **avoids approximately 0.23 MMTCO$_2$e** of GHG emissions in 2030.
- 7.9% of all GHG emissions reductions modeled in the EPS are attributed to mode shifting.

Altogether, clean transportation-related policies modeled in the EPS help Rhode Island avoid 0.56 MMTCO2e of GHG emissions in 2030.

Thermal - Energy Code

1. **Strengthen RI's Building Energy Code**

- More efficient building codes are vital to eliminate wasted energy, lower energy bills, and reduce carbon emissions that cause climate change.
- Under this scenario, the EPS modeled continuous adoption of the most recent IEEC model energy code for residential buildings and the most recent ASHRAE Standard 90.1 for commercial buildings for all code cycles falling between 2021 and 2030.
- Improvements to energy code efficiency requirements combined with an estimated rate of new construction in the state over the next decade results in an estimated **1.3% reduction in total building energy use in the state by 2030** relative to the BAU scenario.
- Through this scenario, Rhode Island **avoids 0.04 MMTCO$_2$e** of GHG emissions in 2030.
- 1.5% of all GHG emissions reductions modeled in the EPS are attributed to strengthening energy codes.

Thermal - Electrification

1. **Increase Efficient Electrification of Building Space and Water Heating**

- The persistent reliance on fossil fuels makes buildings one of the largest sources of GHG emissions.
- Under this scenario, the EPS modeled an **aspirational target of 15% of space and water heating demand in all buildings** being provided by efficient electric appliances (e.g., heat pumps and heat pump water heaters) by 2030.
- The EPS analysis shows that 22% of sales of new non-electric space heating equipment and 8% of the sales of new non-electric water heating equipment are replaced with the sale of efficient electric equipment from 2021 to 2030.
- Through this scenario, Rhode Island **avoids approximately 0.19 MMTCO$_2$e** of GHG emissions in 2030.
- 6.7% of all GHG emissions reductions modeled in the EPS are attributed the efficient electrification of building space and water heating.

Land Use

1. **Adopt a No Net Loss Forest Policy**

- Trees and vegetation absorb and store carbon dioxide. If forests are cleared, or even disturbed, they release greenhouse gases. Forest loss and damage cause rising GHG emissions.

- Under this scenario, the EPS modeled the adoption of a statewide policy that results in maintaining the existing amount of total forested land (~361,000 acres) in Rhode Island through 2030.
- A no-net loss forest policy through 2030 does not further reduce carbon emissions, but helps limit increases in carbon emissions.
- Further avoidance of forest loss helps steady Rhode Island's ability to sequester carbon.

Please take note of the following key issues which are further explained in the technical appendix attached to this report.

- The EPS uses 2020 as a starting point for Rhode Island when undertaking its modeling for 2030. Note that it is a *projected* estimate (RIDEM has yet to complete a full inventory for 2020).
- The EPS utilizes a generation-based approach for the electric sector that also incorporates RIs renewable energy standard. RIDEM's GHG inventory uses a consumption-based methodology that also incorporates RI's RES. This is an important fact that needs to be acknowledged.
- Rhode Island's recently enacted Renewable Energy Standard and Biodiesel Heating Oil Act (RIGL § 23-23.7) adopted in 2013 and amended in 2021 are directly incorporated into the EPS and accounted for in the '*Business as Usual*' scenario because they have already been adopted into law. Please note that in accordance with the Biodiesel Heating Oil Act, the percent of heating oil composed of bioproduct is assumed to achieve the following blend rates: 2020 (5%), 2024 (15%), 2025 (20%), and 2030 (50%).
- RI's leak prone pipe replacement program was not examined as part of this analysis because the level of uncertainty surrounding EPA's per mile emission factors is too high. We propose that this issue be examined in greater detail for the 2025 Climate Strategy as informed by the Public Utility Commission's (PUC) Future of Gas docket (commencing in 2023).
- The scenarios modeled in the EPS primarily focused on policies considered for adoption between 2020 and 2030.

The most important takeaways from this high-level analysis are:

- Electrifying the transportation sector and installing efficient electric appliances for space and water heating (e.g., heat pumps) combined have the most significant impact on GHG reductions in RI between 2020 and 2030.
- Adoption of all the scenarios previously discussed result in a 40.8% reduction in GHG emissions by 2030.
- Although the model indicates RI is projected to be 6.6% away from the Act on Climate's 45% reduction mandate in 2030, adoption of the highlighted policies is critical to putting the state on the correct path for large-scale emissions reductions.

Please refer to the technical appendix for further details and explanation of the EPS methodology and policy assumptions used.

Climate Change: Local Action for a Global Issue

The following is an excerpt from the RIEC4 Event: A Conversation with Senator Whitehouse, hosted on February 11, 2022.

Question: How do you respond to people who say, "Hey it's just little Rhode Island, it's not going to make any difference?" What do you think the value is of the work that we're doing, in terms of leading by example, or just trying to set the stage for bigger things?

Senator Whitehouse:

It was little Rhode Island that created the first conservation-based electric rates in the country back in the late 80s when it was still Narragansett Electric and now you see those everywhere. It was an entirely new way of thinking about regulation and how you compensate utilities, not for selling more electricity, but for actually reducing how much they create and burn.

So Little Rhode Island has had some big, big leadership that plays out still across the country and, frankly, across the world, so, you know everything has to start somewhere, but was it Margaret Mead that said "never doubt that a small group of committed individuals can change the world - in fact, it's the only thing that ever has". We can be that small group of determined people in a lot of ways, and then good ideas take on a life of their own.

Priority Actions for the Electric Sector

There are two ways to reduce emissions from the electric sector: consume less electricity and meet electricity needs using decarbonized energy resources. The Rhode Island General Assembly enacted a 100% Renewable Energy Standard that must be met by 2033. The 100% Renewable Energy Standard is expected to grow demand for renewable energy resources; this, in turn, will require strategic investments in our electric grid to enable timely and efficient integration of these resources, as well as bolstering cost-effective renewable energy within Rhode Island's portfolio through procurement of offshore wind. All actions must be considered within the larger fabric of policy objectives, and should be refined to improve affordability, equity, land use, and other policy objectives. The following table summarizes priority actions, which are described in more detail below. We additionally summarize recommendations from key recent and relevant studies in recognition that action must happen across the board.

Table X. Summary of Priority Actions in the Electric Sector

Action	Impact	Lead(s)	Select Considerations
Implement the 100% Renewable Energy Standard	100% reduction in greenhouse gas emissions when 100% target is achieved through REC retirement	Public Utilities Commission	Track schedule of increasing requirement yearly through 2033
Modernize the electric grid	Enables the electric grid to more readily integrate distributed energy resources and improve	Electric distribution utilities propose investments	Timing of investments, scale of investments, use of technologies

	customer energy management	Public Utilities Commission regulates	
Deploy advanced metering	Enables time-varying utility rate designs; allows customers to better manage their energy use; provides additional visibility into the electric grid	Electric distribution utilities propose investments Public Utilities Commission regulates	Interaction with grid modernization proposal, timing of deployment, subsequent rate design considerations
Procure offshore wind	Expands renewable energy generation portfolio	Electric Distribution Utility Public Utilities Commission regulates	Local economic development, scale and timing, contract structure
Continue energy efficiency work	Continue and further evolve programs to capture additional energy savings	Utilities	Effective investments
Complete RGGI Program Review and implement suggested changes	Supports regional decarbonization	RIDEM	Equitable investments

Implement the 100% Renewable Energy Standard

During the 2022 legislative session, a 100% Renewable Energy Standard (RES) was passed by the RI General Assembly and signed by Governor McKee. The RES ensures we decarbonize the electric sector with yearly targets. Rhode Island's Renewable Energy Standard is an existing statutory mechanism by which we can require electricity suppliers to meet an increasing percentage of retail electric sales from renewable energy resources. The Renewable Energy Standard also sets forth an accounting methodology and process to ensure compliance.

The newly passed Renewable Energy Standard, initially enacted in 2004 and subsequently revised in 2022, sets a statewide target of 100% renewable energy by 2033. Electric distribution companies and non-regulated power producers must comply with the mandate by supplying an increasing percentage of their retail electric sales from renewable energy resources through the purchase and retirement of Renewable Energy Certificates (RECs).[58]

[58] See the discussion on pages 25-28 in the Greenhouse Gas Emissions Inventory chapter for a complete description of how the Renewable Energy Standard works and its interaction with Rhode Island's greenhouse gas emissions inventory.

The impact of a 100% RES is that the emissions reduction may be as large as fully eliminating emissions from the electric sector, as it relates to electricity as an end-use. In 2019, emissions from electricity consumption were estimated to account for 18.9% of total economy-wide emissions. If the 100% Renewable Energy Standard were met in whole by the purchase of Renewable Energy Certificates, then Rhode Island would reduce its greenhouse gas emissions by 18.93%. [59] [60] [61] [62]

The schedule and yearly targets set forth in the 100% RES mandate steadily increase over time starting with an additional four percent of retail electricity sales in 2023 and increases until an additional 9.5% of retail electricity sales are needed in years 2032 and 2033. Additionally, the law requires municipalities participating in municipal aggregation to possibly include voluntary renewable energy products to be counted toward the annual targets.

Any impact to electricity costs should be considered within a larger macroeconomic context. For instance, the war in Ukraine has and will continue to result in increased fuel prices, which in turn increase electricity supply costs. Communities continue to struggle with the economic downturn from the COVID-19 pandemic. Supply chain challenges are not only delaying shipments necessary to our energy landscape but are causing cost increases as well for commonplace technologies. However, implementing the 100% Renewable Energy Standard is one of the most important steps Rhode Island has taken towards statewide, economywide decarbonization.

Modernize the Electric Grid

The current electric grid is built for one-way flow of electricity from a few large power generators to many end-use customers. However, decarbonizing the electric grid necessitates a paradigm of two-way power flow between renewable energy systems of all sizes distributed throughout the electric grid to all customers. Safely, reliably, and affordably building out the electric grid will require electric distribution companies to make strategic investments in technologies for a twenty-first century electric grid.

Grid modernization technologies serve the purpose of managing power flow, protecting workers and customers, improving visibility into electricity consumption and grid conditions, building resilience from power outages, and giving customers more choice and control over their electricity use.

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[59] This simple estimate is *ceteris paribus*: the estimate assumes all else is held equal (e.g., no increase in electricity consumption) and only the Renewable Energy Standard is changed.

[60] More completely: Rhode Island would reduce its emissions by 26.3% below 2018 levels. Emissions resulting from electricity consumption in 1990 were estimated using a different methodology that prevents robust sector-specific comparison between years.

[61] This statement is true if our annual emissions accounting methodology is in place. If instead Rhode Island were to move to a more temporally granular method of emissions accounting, then the emissions reduction impact of a 100% Renewable Energy Standard would be smaller. If hourly accounting capabilities are available, Rhode Island can then consider the value of enacting a more stringent Renewable Energy Standard that requires the timing of renewable energy production (or more specifically, its release into the electric grid for retail consumption) to match the timing of demand. See, for example, Massachusetts's Clean Peak Standard or discussions of private investment in 24/7 clean energy. Moving to this level of standard would not be without cost (e.g. required for energy storage build out), so we recommend first prioritizing increasing the Renewable Energy Standard and then exploring any further enhancements in the 2030s and 2040s, when hourly accounting capabilities exist for both emissions and Renewable Energy Certificates and energy storage is more commonplace and less expensive.

[62] This estimate excludes emissions resulting from methane leakage in Rhode Island's gas distribution system where that gas is used to fuel electricity generators. As gas-fueled electricity generators decrease production in Rhode Island, emissions from methane leakage will decrease accordingly.

Deploy Advanced Meters

Meters that measure electric (and gas) consumption for utility accounts range in capability from simple counting and aggregation of energy use over a billing period to detailed accounting of consumption throughout minutes-long intervals and real-time communication with customers. Most meters in Rhode Island are more like the former – conventional meters that report how much energy a customer uses over the course of a month – and the majority of those meters are reaching the ends of their useful lives.

As Rhode Island considers how to replace its legacy meter system, advanced meters may be the more cost-effective option that also supports progress toward our climate mandates. The granularity of data and method of data communication that advanced meters use allows for innovative rate designs that deliver appropriate signals about the true cost of electricity use throughout the day and year, enables customers to better understand and control their electricity use, and provides important visibility into the electric grid that allows us to make the most use of our infrastructure.

Procure Offshore Wind

Offshore wind is a not only a vital renewable energy resource but a significant economic driver of growth and jobs in Rhode Island. As we move to implement the 100% Renewable Energy Standard, offshore wind will play a critical role in affordably meeting both our in-state renewable energy requirements as well as supporting the region as a whole.

On July 6, 2022, Governor Dan McKee signed a bill into law adding 600 to 1,000 additional megawatts of offshore wind to Rhode Island's clean energy portfolio. Rhode Island Energy released a request for proposals for public comment through the Public Utilities Commission in the Fall of 2022. RIE formally released the RFP in October and responses by interested bidders are expected in early 2023. A final decision on the winning projects will occur later in the year, and contract(s) with developers will be reviewed and approved Public Utilities Commission. It is expected that any new offshore wind projects procured through the RFP would be operational during the first half of the 2030's.

Continue Energy Efficiency Work

Energy efficiency programs in Rhode Island helps residents and businesses adopt and install technologies that allow them to receive the same or better performance from their equipment, buildings, and appliances while using less energy. Rhode Island's energy efficiency programs are offered through the state's utilities and from the Rhode Island Office of Energy Resources. These services can directly lower energy bills for participating consumers, reducing both emissions and energy costs for all consumers, which help support the local economy, and combat climate change. Since 2005, ratepayer-funded energy efficiency programs have saved Rhode Island consumers about 15,400 GWhs of electricity. The impact of these savings means that Rhode Island's electric load is 9% lower than it was in 2005. Since 2009, Rhode Island's ratepayer funded energy efficiency programs have provided over $4.5 billion in realized benefits. This compares to total program costs of about $1.6 billion, resulting in a cumulative benefit-cost ratio of 2.8.[63] In 2021, Rhode Island's least cost procurement statute was extended to 2029, which ensures the energy efficiency programs for the next seven years.[64]

[63] Rhode Island Energy Efficiency and Resource Management Council 2022 Annual Report
[64] Least Cost Procurement: http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM

Complete RGGI Program Review and implement suggested changes

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia to cap and reduce CO2 emissions from the power sector. It represents the first cap-and-invest regional initiative implemented in the United States. Rhode Island has continued to be an active participant in RGGI since 2009. A Third Program Review is currently underway throughout 2021-2023, which will inform RGGI program design for future years. Once the ongoing Third Program Review is completed, Rhode Island can examine adopting new program design elements aimed at continued reduction in greenhouse gas emissions in Rhode Island and the region. The 2025 Climate Strategy should be informed by and responsive to the recommendations of the RGGI Third Program Review.

Table X. Summary of Remaining Recommendations for the Electric Sector from Select Recent and Relevant Studies

Report Title	
Status	Recommendation
100% Renewable Energy by 2030	
Complete [65]	We must ensure we meet our clean energy goals by advancing a 100% Renewable Energy Standard.
Complete [66]	Continued efforts to decrease energy consumption necessitate extension of Least-Cost Procurement and Nation-Leading Energy Efficiency Programs.
Underway [67]	Maintain continued support for in-state renewable energy development, while supporting programmatic evolution to deliver more affordable and sustainable outcomes.
Underway [68]	Optimize the electric grid through integrated grid planning.
Priority action [69]	Facilitate integration of distributed energy resources by deploying Advanced Metering Functionality and Grid Modernization technologies.
On the horizon[70]	Build out a strategic role for energy storage technologies.
Underway [71]	Continue regional collaboration on wholesale markets and interstate transmission.

[65] RIGL39-26.4
[66] RIGL39-1-27.7
[67] The Division of Public Utilities and Carriers is conducting a study to understand programmatic costs and benefits.
[68] The Office of Energy Resources, National Grid, Regulatory Assistance Project, and Lawrence Berkeley National Lab are developing an exploratory pilot project to understand process options and viability.
[69] Modernizing the electric grid, which includes upgrading metering functionality, is a priority action for the short-term. Other recommendations from the Power Sector Transformation Report are noted within this table.
[70] This recommendation is ripe for further consideration and discussion in the development of the *2025 Climate Strategy*.
[71] See https://newenglandenergyvision.com/ for more information about this effort.

Needs more work	Partner with trusted community organizations to listen, learn, support, and establish foundational definitions. Based on foundational definitions, develop equity metrics with the community to track and monitor progress towards equitable outcomes. Improve outcomes identified and prioritized by communities through rate design, program adjustments, and policy.
Power Sector Transformation	
Implemented [72]	Create a multi-year rate plan and budget with a revenue cap to incentivize cost savings.
Ongoing [73]	Shift to a pay-for-performance model by developing performance incentive mechanisms for system efficiency, distributed energy resources, and customer and network support.
Ongoing[74]	Develop new value streams from the distribution grid to generate third-party revenue and reduce burden on ratepayers.
Ongoing	Update service quality metrics to address today's priorities, including power outage prevention, cyber-resiliency, and customer engagement.
Needs more work	Assess the existing split treatment of capital and operating expenses.
Priority action	Deploy advanced meters.
Ongoing	Plan for third-party access and innovation.
Ongoing	Share the cost burden of advanced metering through partnerships.
Ongoing	Focus on capabilities to avoid technological obsolescence.
Ongoing	Proactively manage cyber-resilience.
Implemented [75]	Synchronize filings related to distribution system planning.
Ongoing	Improve forecasting.
Ongoing	Establish customer and third-party data access plans.
Ongoing [76]	Compensate locational value.

[72] See Commission Docket 4770.
[73] See for example Commission Docket 4943.
[74] This will likely be a consideration in any future electric distribution utility filing requested cost recovery for investments in grid modernization and advanced metering. See stayed Commission Dockets 5113 and 5114.
[75] See Commission Docket 5015.
[76] See for example National Grid's process for procuring non-traditional electric grid solutions.

Ongoing and on the horizon [77]	Design rates to increase system efficiency.
Ongoing	Establish outcome-based metrics.
Needs more work	Beneficial heating proposals should be consistent with principles outlined in the Commission white paper on beneficial electrification.
Solar Siting Opportunities	
Ongoing	This report estimated viability of solar in preferred locations. Considerations are embedded throughout the report,
Docket 4600	
Ongoing	This report included a number of next steps for the Public Utilities Commission to consider, some of which fed into the Power Sector Transformation report and subsequent work to develop a grid modernization plan and advanced metering functionality business case in collaboration with National Grid's Power Sector Transformation Advisory Group.
Energy Efficiency Market Potential Study	
Ongoing	There is significant opportunity to expand DR programs in RI in a cost-effective manner, both through growing the market for existing programs, and introducing new measures and programs.
Ongoing	C&I lighting remains by far the largest opportunity, both in terms of annual and lifetime savings.

Building an Integrated Portfolio of Action

Framing our emissions reduction journey by the largest emissions categories— thermal, transportation, and electric—provides a clear starting point for assessing our baseline and organizing our actions. As we move along in the process, however, it becomes clear that we cannot draw clear lines between these sectors. So many systems, both big and small, overlap and these overlaps will only continue to change, as we adjust the way we do things to decrease our emissions.

For example, our food systems produce emissions through agricultural practices, processing, distribution, refrigeration, cooking, and waste. This one supply chain includes emissions from the electric sector, the transportation sector, and the thermal sector. Another example is heating. We currently use a mix of fuels and technologies to heat our buildings, and as we decarbonize, that mix will continue to change, overlap, and have greater implications on other sectors. When we begin to look at the ways in which different areas of our energy usage are integrated with each

[77] In Commission Docket 4770, the Commission approved a performance incentive for meeting system efficiency targets; however, rate designs specifically targeting system efficiency are not likely to be proposed until metering functionality is improved (i.e. such as to allow for time-varying rate structures).

other, we can find additional priority actions that more strategically reduce emissions across the board.

As policymakers, we often rely on benefit-cost assessments to understand the potential impacts of choosing different options. When we conduct benefit-cost assessments on single actions, or sets of siloed actions, we lose sight of the integrated and indirect benefits and costs that ripple throughout the entire system. Looking at the big picture, can change how we interpret the benefits and costs in a small part of it.

For example, if we prioritize only the low-hanging fruit—actions with the biggest benefits and the lowest costs—then we may find ourselves in a place where our remaining actions are no longer cost-effective. We also run the risk of not seeing the full scale of benefits across our holistic set of policy objectives. Looking at the collective benefits and costs of an entire portfolio of actions, can help us see the full effect of our actions.

It is for this reason that, in this report, we not only organize our priority actions by sector (electric, transportation, thermal, land use, etc.) but we also include these integrated callouts on health, food systems, buildings, and youth. Discussing these integrated systems helps us understand additional priority actions that we must take, not only to meet our climate mandates, but also to improve things like the health, comfort, safety, affordability, resilience, equity, and the vibrancy of our Rhode Island communities.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a multi-state, market-based program to cap and reduce carbon dioxide (CO_2) emissions from electricity generating power plants. Through independent regulations (based on the RGGI "Model Rule"), twelve Eastern states currently participate in this cooperative effort. Launched in 2009, RGGI was the first mandatory greenhouse gas "cap-and- invest" program in the United States. The regional cap on CO_2 emissions is set by the RGGI states. Together, the RGGI states' individual emissions caps (or CO_2 budgets) are equal to shares of the regionwide cap. This cap sets a limit on the emissions from regulated power plants in the RGGI states' and declines over time in a planned and predictable way.

Since its conception, RGGI emissions have been reduced by more than 50% RGGI-wide and the RGGI program has contributed to the decarbonization of the electric sector. Fossil fuel-fired power plants with a capacity of 25 megawatts or greater must acquire enough RGGI allowances to cover their CO_2 emissions. Electric generation facilities in the RGGI states obtain allowances primarily through quarterly auctions. The RGGI states receive the proceeds from selling RGGI allowances and each state has discretion over how best to use their proceeds. Over $5 billion has been raised RGGI-wide from the allowance auctions. Generally, the proceeds have been invested by states back into their communities including funding of energy efficiency, clean energy programs, renewable energy deployment and direct rate relief for low-income consumers. As of September 2022, RI's proceeds from all auctions total approximately $116 million.

The RI Office of Energy Resources (OER) with guidance from RIDEM determines the allocation and distribution of RI's RGGI auction proceeds. In 2022, RI auction revenue supported numerous programs including the RI Commerce Corporation's Renewable Energy Fund (REF), LED *lighting in public schools, air-source heat pump incentives, RIDEM Energy-Savings Trees Program and RI Agricultural Energy Grant Program. Two programs directed towards low- and moderate- income (LMI) customers; the Affordable Solar Access Pathways Program (ASAP) and the Zero Energy for the Ocean State (ZEOS) were also funded by RGGI auction proceeds. In addition, approximately 5 million in electric bill credits to low-income customers were also supported by RGGI revenues.*

Priority Actions for the Transportation Sector

There are two ways to reduce emissions in the transportation sector: consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions and take action to incentivize lower-emissions mobility.

Table X. Summary of Priority Actions for the Transportation Sector

Action	Impact	Lead(s)	Select Considerations
Increase light-duty ZEV penetration to at least 10% by 2030.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	Administration (RIDOT, RIDEM, OER, DMV, Commerce, RIIB)	Incentive programs, interaction with electric vehicle charging infrastructure. State fleet transportation Lead by Example.
Implement Transit Forward RI 2040, Rhode Island's Transit Master Plan, to grow transit ridership from 53,000 to 87,000 daily passenger trips. Look to the Transit Master Plan and Bicycle Mobility Plan for next steps and consider committing resources to key projects.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIPTA, Division of Statewide Planning, RIDOT	This will mitigate 231,000 MTCO2e. [78] Projects in the TMP and BMP are planned on a conceptual level. The next step is to evaluate needs and connections.
Reduce RIPTA's carbon footprint by decarbonizing Rhode Island's transit fleet.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIPTA	This will mitigate 14,122 MTCO2e. [79]
Maintain increasing fuel economy and low-and zero-emission vehicle standards.	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIDEM	Maintain adherence to Corporate Average Fuel Economy and GHG emission standards.

[78] Estimates are from the TCRP Land Use Benefit Calculator as provided by RIPTA.
[79] Estimates are from the TCRP Land Use Benefit Calculator as provided by RIPTA.

			Maintain adherence to California low-emission and zero-emission vehicle requirements. Includes amending existing rules to incorporate Advanced Clean Cars II. Adopt New Rules: California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers.
Incentivize electric mobility	Enables switch to electric vehicles	Office of Energy Resources	New and used, personal and fleet, BEV, PHEV and MHD, future expansion of incentives to e-bikes. Utilize Diesel Emissions Reduction Act (DERA) funds to provide incentives to RI entities to replace older diesel engines and vehicles with cleaner and zero-emission alternatives.
Model climate impacts of transportation demand (in Unified Planning Work Program)	Allows weighing climate impacts of transportation investment decisions among policy objectives	Division of Statewide Planning, RIDOT and RIDEM	This is not an issue only at the state level, but nationally and regionally. RIDOT and RIDSP will work together with other federal, state and regional partners to improve the GHG modeling capacities as this is a FHWA requirement for transportation capital projects and establish a model for decision-making.
Develop 'complete streets' state plan leveraging federal funding	Reduces fuel consumed through decrease in vehicle miles traveled and encourages lower-emissions mobility	Division of Statewide Planning, RIDOT and RIPTA	The IIJA resulted in specific formula funding set-asides for developing a Complete Streets plan and implementation strategy: RIDSP will be the lead but work closely with a robust group of partners and stakeholders. Anticipated completion in 2025.

Target 10% penetration of electric vehicles by 2030

In the latest Rhode Island Greenhouse Gas (GHG) Emissions Inventory report, the Transportation sector was responsible for the highest gross greenhouse gas emissions (39.7%) by economic sector in 2019. Emerging technologies in the transportation sector, such as electric vehicles, are paving the way for alternative fuels to be used as a solution for reducing GHG emissions. Clean transportation will also deliver substantial energy security and economic benefits as cleaner electricity derived from renewable energy and other low-carbon sources replaces imported gasoline and diesel as transportation fuels.

As of October 2022, Rhode Island has 6,275 registered electric vehicles, which is a 1,313% increase in EVs since 2015. In order for the transportation sector to meet its 2030 emissions reduction, Rhode Island will need to have roughly 43,000[80] registered EVs on the road. By having programs focused on Zero-Emission Vehicles, such as DRIVE EV, an electric vehicle rebate program available to Rhode Island residents and businesses, it will help increase the amount of registered electric vehicles on the road in Rhode Island as mandated by the 2021 Act on Climate, as well as paving the way for further expansion of EV penetration, post 2030.

Implement Transit Forward RI 2040

Implementing the plan will require an approximate average annual capital investment of $100-160M over 20 years. Operating costs will increase roughly $150M annually, from $130M (2020) to $280M). This action is estimated to grow transit ridership from 53,000 to 87,000 daily passenger trips and to mitigate 231,000 MTCO2e,

As resources are available, look to the Transit Master Plan (TMP) and Bicycle Mobility Plan (BMP) as well-vetted strategies for next steps

RIDOT, RIPTA, and RIDSP have all developed planning work tasks to support mapping, evaluation, and implementation of projects and priority corridors which were recommended in the TMP or BMP respectively. These agencies continue to prioritize projects advancing better connections for both transit and bicycle/pedestrian modes as the state looks to identify funding for the TMP and BMP. Some of the projects related to these steps include funding for long-range planning studies that take conceptual proposals and prepare design and cost details. In addition, staff resources are used to map the projects in the BMP and TMP to show where overlap may occur with existing planned projects, allowing incorporation of bike, pedestrian, and transit components into projects already programmed in the STIP.

Reduce RIPTA's carbon footprint by decarbonizing Rhode Island's transit fleet.

The full cost of fleet decarbonization is currently unknown. RIPTA is preparing an Action Plan for Electrification and Service Growth which will provide estimated annual decarbonization infrastructure, vehicle, and energy costs. This plan will be complete by June of 2023.

Adopt Advanced Clean Trucks rule

The federal Clean Air Act (CAA) grants the U.S. Environmental Protection Agency (EPA) original jurisdiction for establishing emission standards for new motor vehicles, including heavy-duty trucks. Section 209(a) of the federal Clean Air Act (42 USC § 7543) prohibits states (except California) or other political sub-divisions, such as local or regional governments, from establishing emission standards for new motor vehicles.

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[80] This estimate is based on an internal scatter model used by Rhode Island Energy (RIE).

Under CAA Section 177 (42 USC § 7507), however, states that choose to adopt vehicle emission standards that are more stringent than the federal standards for new vehicles may adopt standards that are identical to any standards adopted by California.

Rhode Island has previously adopted California's emissions standards for passenger cars and trucks and, through the state's rulemaking process, could further opt-in to California's standards by amending 250-RICR-120-05-37 to include new standards for medium- and heavy-duty vehicles.

Reducing emissions from the vehicles on our road is an important part of Rhode Islands' programs to meet and maintain the health-based National Ambient Air Quality Standards (NAAQS), reduce the risk of exposure to toxic diesel particulate matter, and reduce the GHG emissions that contribute to climate change. The adoption of California's emissions standards is an imperative piece of the puzzle to Rhode Island's response and action on climate change.

Adopt New Rules: California's Advanced Clean Trucks (ACT), the Low NOx Heavy-Duty Omnibus (HD Omnibus), and Phase 2 Greenhouse Gas (Phase 2 GHG) emission standards for trucks and trailers.

- ACT: The purpose of the ACT Rule is to accelerate the widespread adoption of ZEVs in the medium-and heavy-duty truck sector and reduce the amount of harmful emissions generated from on-road trucks. The ACT Rule applies to manufacturers of medium- and heavy-duty vehicles over 8,500 pounds gross vehicle weight rating (GVWR)8 which includes passenger vans, buses, pickups, vocational trucks, box trucks, and tractor trailer combinations used locally and for long-haul applications. The ACT Rule requires manufacturers to sell ZEV trucks as an increasing percentage of their annual sales from model years 2026 to 2035. (**MY26 or MY27 pending if we move forward in 2022 or 2023).

- HD Omnibus: The Heavy-Duty Engine and Vehicle Omnibus (HD Omnibus) Rule and associated amendments require NOx reductions from new on road heavy-duty engines and vehicles and ensure emissions reductions are maintained as those engines and vehicles are operated. The HD Omnibus Rule requires a 90% reduction in NOx emissions from model year 2027 engines.

- Phase 2 GHG: The Phase 2 GHG Rule sets standards to reduce GHG emissions associated with medium- and heavy-duty engines, vocational vehicles, heavy-duty pick-up trucks and vans (PUVs), and applicable tractors and trailers. The Phase 2 GHG Rule requires manufacturers to improve existing technologies or develop new technologies to meet the GHG emission standards. It also amends requirements for glider vehicles, glider engines, and glider kits. The Phase 2 GHG requirements would apply to model year 2026 and newer Class 2b to 8 medium- and heavy-duty vehicles with greater than 8,500 pounds GVWR and the engines that power them, except for medium-duty passenger vehicles already covered in the light-duty regulations. (**MY26 or MY27 pending if we move forward in 2022 or 2023).

Avoided Medium- and Heavy-Duty Emissions, 2020-2040		
NOx (short tons)	PM2.5 (short tons)	CO2e (million metric tons)
4,740	25	1.96
Avoided Medium- and Heavy-Duty Emissions, 2020-2050		
13,080	76	5.59

Table: Cumulative emissions avoided with 2025 implementation of ACT, HD Omnibus, and Phase 2 GHG rules. [81]

Amend Existing Rules to incorporate California's Advanced Clean Cars II:

- Rhode Island Department of Environmental Management will also have the ability to amend our existing Advanced Clean Cars program to adopt California's Advanced Clean Cars II (ACCII). The ACCII ZEV regulation requires that all passenger car and light-duty truck vehicles delivered by manufacturers for sale in Rhode Island by 2035 meet the definition of zero-emission vehicle (ZEV). The ACCII regulation will reduce NOx, PM2.5, and GHG emissions. (**GHG reduction analysis pending)

Incentivize electric mobility

Rhode Island has a history of impactful planning and programming related to clean transportation programs. In the past, the Office of Energy Resources has successfully administered programs incentivizing electric mobility.

Program	Targeted Technology	Program Duration	% Increase
DRIVE	Electric Vehicles	January 2016 – July 2017	20-35% (254 EVs)
Electrify RI	Electric Vehicle Charging Stations	October 2019 – July 2021	83 Operational Charging Stations and 14 Pending Activation (as of August 24, 2022).

The success of the programs implemented in the table above provided several best-practices and mechanisms used to incentivize electric mobility. On July 7, 2022, OER launched an electric vehicle rebate program, DRIVE EV. Driving Rhode Island to Vehicle Electrification (DRIVE) is an electric vehicle (EV) rebate program administered by the Rhode Island Office of Energy Resources (OER) to support adoption of electric vehicles by Rhode Island residents, small-businesses, non-profits, and public sector entities. DRIVE EV also provides additional incentives for qualified Rhode Islanders who purchase or lease an eligible electric vehicle and meet certain income requirements or participate in a State or Federal Income-Qualifying Program.

In the coming years, there will be opportunities to identify long-term, sustainable fundings sources to continue incentivizing electric vehicle adoption. An increased focus on providing additional incentives aimed at reducing the barrier-to-entry costs related to electric vehicles, as well as providing programs aimed at providing electric vehicle charging stations for non-homeowners, and those that live at multi-unit dwellings, as well as businesses looking to transition their fleet.

There are now programs, and incentive opportunities, available for e-bikes. The current DRIVE EV rebate program gives rebates for light-duty electric vehicles, and recently OER expanded the scope to include rebates for e-bikes.

Model climate impacts of transportation demand

Transportation accounts for the largest share of Greenhouse Gas (GHG) emissions in Rhode Island, with passenger vehicles being the largest contributor to pollution caused by transportation related emissions[82]. RIDOT and the Rhode Island MPO must adopt long-range transportation plans that reduce GHGs to set

[81] Source: ICCT Report "Benefits of state level adoption of MHDV Regulations" https://theicct.org/
[82] Per Transportation Emissions Dashboard | Rhode Island Department of Environmental Management (ri.gov)

reduction levels. Current air quality measurements and travel-demand models do not specify GHG levels as they pertain to transportation projects in the STIP, so a new model is needed.

To understand how projects of regional significance in the State Transportation Improvement Program (STIP) contribute to GHG emissions and to assess future policy options and investment strategies towards the reduction of those emissions, Rhode Island Department of Transportation (RIDOT) is working with other state partners to improve the modeling of GHG, establishing performance measures to help reduce emissions and creating a Carbon Reduction Plan per federal guidelines.

Investments in transportation capital projects are prioritized based on many factors, including asset management, readiness, risk levels, available funding and opportunities for partnership. Due to changes in both state and federal regulations and guidelines, this data-driven process now will include another layer that determines how regionally significant projects impact carbon emissions in the state. The state planning process determines these priorities so that adequate investments are made based on the proper funding sources and uses, and to meet mandates such as performance measures.

In addition, the Rhode Island Division of Statewide Planning (RIDSP) hosts and maintains the State's Travel Demand Model.

Develop 'complete streets' state plan leveraging federal funding

In addition to the state requirements around complete streets, Complete Streets law: http://webserver.rilin.state.ri.us/Statutes/TITLE24/24-16/24-16-1.HTM there is a federal requirement to develop a complete streets plan and design guidance. In December 2021, USDOT sent a letter to all state and regional offices to highlight new Planning Emphasis Areas (PEAs), which included Complete Streets as a focus for planning-level funds and projects. The IIJA requires that states and metropolitan planning organizations set aside 2.5 percent of their highway planning funding for designing "complete streets" projects and policies that will improve safety and accessibility for all users of the road.

USDOTs definition of "Complete Streets" as "Streets that are streets designed and operated to enable safe use and support mobility for all users. Those include people of all ages and abilities, regardless of whether they are travelling as drivers, pedestrians, bicyclists, or public transportation riders. The concept of Complete Streets encompasses many approaches to planning, designing, and operating roadways and rights of way with all users in mind to make the transportation network safer and more efficient. Complete Street policies are set at the state, regional, and local levels and are frequently supported by roadway design guidelines."

In Rhode Island, RIDOT and RIDSP have joined together to maximize the impact of that funding. RIDSP will lead a 2.5-year effort to invest more than $250,000 in combined planning funds into development of a Complete Streets Plan and Design Guidelines. This project has kicked off (fall 2022) with a draft RFP for consultant assistance, which RIDSP expects to complete and issue in spring 2023, in coordination with RIDOT and RIPTA. This project is included in the FY2023 Unified Planning Work Program (UPWP), is the annual RIDSP program of projects under development.

Electrifying Transportation Strategic Policy Guide [83]

In December 2021, '*Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island'* was released in response to S-0994 and H-5031, which directed numerous agencies to develop a coordinated plan to improve access to electric

[83] Please see the Electrifying Transportation Strategic Policy Guide for additional recommendations throughout the entire text of the report.

vehicle charging stations across the state. The policy guide highlighted the following key priorities for Rhode Island in the coming years:

- Reinvest in incentive programs for electric vehicles and charging infrastructure;
- Refine electric vehicle and charging infrastructure programs to align with priorities and to center equity such that benefits accrue to underserved and overburdened communities;
- Demonstrate progress in electrifying transit, school buses, and medium- and heavy-duty vehicles in order to reduce harmful emissions and improve public health;
- Conduct an analysis to understand transportation revenue impacts and develop recommendations for future action to ensure sustainable funding streams;
- Support a 100% Renewable Energy Standard to ensure electric transportation is truly decarbonized;
- Develop a clean transportation dashboard to track progress; and
- Demonstrate action through state agency commitments and accountability.

A number of these priorities have already been accomplished or are underway. A specific meaningful action item for all agencies represented by RIEC4 was included in the final guide. The RIEC4 should continue to track progress on all the agency specific action items and coordinate implementation across agencies to maximize impact. Looking ahead, the 2025 Climate Strategy will be able to revisit both the priorities outlined above and the agency specific action items and recommend changes as needed.

Climate and Buildings

Buildings are a significant source of greenhouse gas emissions and contributors to climate change. According to the American Council for an Energy-Efficient Economy (ACEEE), "residential and commercial buildings are responsible for approximately 40% of U.S. energy consumption and GHG emissions."[1] We live, work, and play inside buildings and the operations required to keep the lights on, operate our electronics and appliances, and keep our spaces comfortably heated or cooled require a lot of energy. Buildings also contribute to climate change through the construction process and the manufacturing of the materials necessary for construction. We create buildings to have very long lifespans, which means that how we choose to build or renovate them can have large impacts on the lifetime emissions of those buildings. Altogether, our built environment is both one of our largest contributors to climate change and one of our greatest opportunities for reducing our emissions.

Resilient buildings are important because buildings affect our climate, but our buildings are also impacted by our changing climate. In our coastal areas, flooding will become more common as sea levels rise. Across the state, storms will become more severe, and the number of high heat days that we have in the summer will increase. All of these changes mean that our buildings must also be constructed to be resilient in order to withstand these more intense impacts, and to keep the interiors of our buildings comfortable in more extreme weather conditions.

Decarbonizing the built environment is one way we can reduce GHG emissions of buildings. There are numerous considerations for decarbonizing the built environment that intersect across different sectors. For example, we typically use fossil fuels to heat our buildings, and we use electricity to power an increasingly wide range of appliances. One of the greatest uses of energy in buildings is for space heating and cooling. Switching to renewable sources for energy, heating and cooling our buildings can help to reduce the impact the built environment has on the climate.

Key considerations for the thermal sector and decarbonizing the thermal needs of buildings are issues addressed throughout this report.

We have a variety of tools available to us in Rhode Island to both reduce the emissions that come from our built environment and to strengthen the resilience and adaptability of our buildings.

Strengthen Building Energy Codes

Building codes are one of the tools available for improving our buildings. Building codes provide a baseline set of rules that all new construction projects must comply with to ensure the safety and energy efficiency of buildings. The State's building codes are generally updated every three years through a public process to raise the bar on the minimum standards of safety and efficiency. The State also has a stretch code in place, which is a more ambitious building code that developers can choose to comply with in order to build more efficient buildings. Building codes can help the State set the trajectory for net-zero green building standards, prepare our new buildings to be EV- and solar-ready, and prepare our buildings to be completely electrified.

Implement the Updated Green Buildings Act Legislation and Continue to Assess and Recommend Opportunities for Improvement

The Green Buildings Act was signed into law in 2009 to require public agencies to design and construct projects and renovations to meet a LEED-certified of equivalent high performance green building standard. In 2022, the Green Buildings Act was amended to specify that these requirements apply to all new construction projects and renovations of 10,000 square feet or larger. The Green Buildings Act is administered by a Green Buildings Advisory Committee comprised of State agency representatives and members of the public. The Committee will continue to assess and evaluate the implementation practices of the Green Buildings Act, including conducting studies as needed, to provide recommendations for achieving the State's goals related to public facility emissions. By ensuring improved compliance with the Green Buildings Act, the State can help reduce emissions from public buildings and facilities throughout the state.

Coordinate Climate Considerations with New Housing and School Investments that Use Public Money

There are many efforts being made to use public funds to reduce harmful climate impacts in the state, including with new housing and school investments. One program is the Zero Energy for the Ocean State (ZEOS) program, which is a partnership between the Office of Energy Resources and RI Housing. This program provides Regional Greenhouse Gas Initiative (RGGI) funding to affordable housing developments to create net-zero energy housing for low- and moderate-income residents. The State's School Building Authority is also able to leverage its funding to ensure that school construction projects are built to high energy and environmental standards. School districts looking to renovate existing buildings or construct new facilities can receive 30 to 98 percent in funding reimbursements for those projects, if the projects are constructed to meet the New England Collaborative for High Performance Schools criteria (NE-CHPS). State agencies continue to seek additional opportunities to leverage federal funding for reducing emissions from Rhode Island's built environment. These efforts will allow new building stock to advance climate mandates and deliver non-energy benefits to all.

Priority Actions for the Thermal Sector

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island. Because of the variety of energy sources, emissions accounting for the thermal sector is spread across different categories in the state's greenhouse gas reporting. Over the next decades, the fuel sources we use for the thermal sector will begin to shift as we transition to lower emissions fuels.

At a high level, the two primary ways to reduce emissions from the thermal sector are to, 1) consume less fuel, and 2) to consume lower emissions fuels. Consuming less fuel means optimizing efficiency and reducing wasted fuel or heat that does not get used for its primary purpose or providing heating or cooling to Rhode Islanders. The ways we can use lower emissions fuels are summarized in Figure X and generally involve two over-arching pathways: strategic electrification and decarbonized fuels.

<table>
<tr><td rowspan="5">Thermal Processes</td><td rowspan="3">Strategic electrification</td><td>Air Source Heat Pumps (ASHPs)
-e.g., air to air, air to water heat pumps</td></tr>
<tr><td>Ground Source Heat Pumps (GSHPs)
-e.g., ground to air, water to air heat pumps, and geothermal district systems</td></tr>
<tr><td>Thermal Energy Storage
-e.g., heat batteries</td></tr>
<tr><td rowspan="2">Decarbonized Fuel</td><td>Renewable Liquid Fuels
-e.g., biodiesel, ethanol</td></tr>
<tr><td>Renewable Gases
-e.g., renewable natural gas, hydrogen</td></tr>
</table>

Figure X. Thermal Decarbonization Pathways (adapted from the Heating Sector Transformation Report)

Table X summarizes priority actions for decarbonizing the thermal sector. The priority actions focus on consuming less fuel, consuming lower emissions fuel, or a combination of both.

Table X. Summary of Priority Actions in the Thermal Sector

Action	Impact	Lead(s)	Select Considerations
		Energy Efficiency	
Continue Energy Efficiency and Weatherization	Efficiency standards can continue to be improved for heating equipment, and weatherization incentives and programs can further be enhanced by the utilities and the state.	Utilities and State Agencies	Extensive federal funding for electrification is expected in coming years; weatherization programs should ramp up to use funding effectively

Strategic Electrification			
Target 15% penetration of energy efficient electric heating by 2030	≈ 0.19MMTCO2e reduction in greenhouse gas emissions (in 2030)	OER and RIE	Workforce training, consumer education, utility coordination
Pursue district geothermal	Pilot most efficient electric thermal system	OER and RIE	Utility coordination, community involvement, integrated systems and planning
Incentivize efficient electric heating technologies	Increases affordability of technologies and spurs market growth	State and federal government	Funding streams and associated limitations, consumer and contractor trust and awareness
Decarbonized Fuels			
Increase biofuel blending in accordance with the 2021 Biofuel Heating Oil Act	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	Industry	Equipment compatibility, cost and quantity of supply, life cycle carbon intensity and environmental impact
Continue to abandon leak-prone gas pipes and pursue non-pipe alternatives	The GHG emission impacts of this action will be modeled as part of the 2025 Climate Strategy.	RIE DPUC + PUC	Evaluate whether replacement is consistent with climate mandates
Pursue hydrogen demonstration projects in coordination with the Northeast Regional Hydrogen Hub	Creates opportunities for decarbonization of hard to electrify areas, such as high-heat industrial processes	State of RI, led by OER; Northeast Hydrogen Hub state and private sector partners	Technology research and development, workforce development, zoning, codes, safety regulations
Continue to pursue solutions to reduce emissions from solid waste	Lowers direct emissions from waste, creates source of renewable methane	OER in coordination with relevant waste facilities	Overlap with biofuels and biogas planning, ideally solid waste amounts decrease in future, consider implications on renewable gas supply
Future of the gas distribution system	Enables cost-effective decarbonization, planning, and aligning utility business model	PUC	Trimming branches of the distribution system where we can electrify, strengthening branches where we can't electrify
Begin developing a renewable thermal standard	Progressive scale down of thermal sector emissions	Legislature	Interplay of all different decarbonization technologies, cost effectiveness, jobs impacts, rethinking role of the utility

Prioritize Efficiency to Decrease Fuel Usage

The first way to reduce emissions from the thermal sector is to improve energy efficiency, so we use less fuel. This can be done by improving the efficiency of appliances and by improving the weatherization of buildings.

Continue Energy Efficiency Programs and Weatherization

Weatherization of buildings is key to ensuring a successful transition to decarbonized heating and cooling, because it helps to decrease our overall energy demand. While the utilities' efficiency programs support a number of weatherization programs and appliance efficiency standards, these should continue to be expanded.

Strategic Electrification

One pathway to thermal decarbonization is through strategic electrification. Converting thermal processes from fossil fuel power to energy efficient electric appliances can reduce emissions immediately. Air source heat pumps, for example, are three times more efficient at providing heat than fossil fuel heating systems, resulting in an immediate increase in fuel efficiency. The emissions of electric appliances for thermal processes will continue to decrease to zero, as we move toward the state's 100% Renewable Energy Standard by 2033.

Converting fossil fuel technologies to electric power will pose new challenges for our electric grid. According to the Heating Sector Transformation Report, 100% electrification of the thermal sector is not only unlikely, but also not cost effective.[84] Electrification is not appropriate for certain components of the thermal sector, such as high-heat industrial processes. Additionally, we must be cognizant of the impacts heat pump conversions will have on our electric distribution system. As we design incentives and other mechanisms to support the market for electrification, we need to remain strategic in how we plan for necessary changes to the electric system and simultaneously support other decarbonization technologies to reach our emissions reductions targets.

Target 15% penetration of energy efficient electric heating by 2030

A conversion of 15% of Rhode Island's buildings from fossil fuel heat to efficient electric heating by 2030 is an aggressive, but attainable and necessary target. This rate of conversion will reduce thermal sector emissions by an estimated 0.19MMTCO_2e[85]. While the market for efficient electric heating—including a variety of heat pump technologies—is relatively nascent in Rhode Island, the next several years will be used to build a strong foundation for the market to expand at a quicker pace in the last two decades as we approach 2050. The priority actions below, will help us reach this 15% target and plan for further expansion, in tandem with other decarbonized thermal technologies, post 2030.

Efficient heat pump incentives

There are several mechanisms for incentivizing efficient heat pumps that are expected to be used in the coming years. First, the Office of Energy Resources will be launching the High Efficiency Heat Pump Program (HHPP)[86] in 2023, which will combine federal funding from the American Rescue Plan Act (ARPA) with existing incentives provided by Rhode Island Energy's energy efficiency programs. The aim of the program is to create a robust incentive program, extending greater financial incentives to more Rhode Islanders who want to convert to efficient heat pumps. The program will also emphasize education

[84] https://energy.ri.gov/heating-cooling/heating-sector-transformation
[85] Please see "Meeting our 2030 Mandate" and Acadia Center's Technical Appendix at the conclusion of this report for additional details.
[86] https://energy.ri.gov/heating-cooling/high-efficiency-heat-pump-program

and workforce development to build a sold market for this efficient, and ultimately emissions-free, thermal technology.

Second, the Inflation Reduction Act, recently passed by the U.S. Congress, will provide a suite of incentives including tax credits and rebate programs for heat pumps and other electric thermal appliances, such as induction stoves. The State will work diligently to ensure that the maximum benefits are easily accessible to Rhode Islanders and that federal incentives for heat pumps compliment State offerings.

Third, in the coming years, there will likely be opportunities through policy and regulation to identify long-term, sustainable funding sources for efficient electric heat that go beyond one-time federal stimulus funding. While federal funding can provide a very solid basis for standing up efficient electric heating programs, there may be a need to craft novel funding mechanisms that can carry electrification efforts well into the future.

Pursue district geothermal

District geothermal systems are being piloted in neighboring states as a solution for providing extremely efficient electric-powered heating and cooling that is delivered by a thermal utility company. Traditionally, gas utilities have delivered fossil fuel to customers connected to the gas distribution system to fuel heating appliances. Geothermal systems (a.k.a. ground source heat pumps) use the least amount of energy to deliver space heating and cooling, of all the electric thermal technologies currently available. Drawbacks to geothermal include high upfront costs, and disruptive installation practices, which involve drilling, and/or laying pipe in the ground or a body of water. Once geothermal systems are installed though, they have an extremely long lifespan and very low operating costs—providing clean, affordable, and reliable heating and cooling to customers.

The challenges with geothermal systems make it difficult for many homeowners to install these systems themselves; gas utilities, however, are uniquely well-positioned to carry the high upfront costs and engineering challenges given their experience with large scale infrastructure projects. In the next 1-3 years, OER will work together with the utility to assess the opportunities for district geothermal.

Decarbonized Fuels

Priority actions in this category mainly focus on using lower emissions fuels and using them more efficiently, but also contain actions to consume less fuel, by avoiding emissions caused by wasted fuel.

Increase biofuel blending in accordance with the 2021 Biofuel Heating Oil Act

The 2021 Biofuel Heating Oil Act requires that, by 2030, all No. 2 distillate heating oil sold in Rhode Island, "shall at a minimum meet the standards for B50 biodiesel blend and/or renewable hydrocarbon diesel."[87] This means that by 2050 all heating oil in the state will contain at least 50% biodiesel, significantly decreasing the carbon intensity of home heating oil.

As the state moves incrementally toward the 2030 biofuel mandate, it will be necessary to consider the impacts on customers, heating oil companies, and emissions. In the next two to three years, as biodiesel blending mandates increase, it will be important to anticipate and monitor potential implications of using higher biodiesel blends with existing heating equipment. Generally, biodiesel is considered a "like-for-like" swap with heating oil, because it can be used with existing oil boilers and furnaces. There are, however, concerns that higher biodiesel blends can wear on existing heating systems and may require retrofits.

[87] http://webserver.rilin.state.ri.us/BillText/BillText21/HouseText21/H5132A.pdf p. 3

Additionally, in the next two to three years, compliance plans for the mandate should be made. Currently, there is no robust system for monitoring compliance with the blending mandate, nor are there requirements for biodiesel feedstocks and sourcing, both of which greatly impact the emissions profile of biodiesel. At this time, there is a very limited supply of bio-based fuels and in the context of significantly increasing global demand, future biodiesel prices are a concern. Therefore, we must consider strategies for mitigating the impacts of supply-side cost increases on local business.

While biodiesel has fewer greenhouse gas emissions than fossil diesel, using biodiesel and other bio-based fuels for heating still results in emissions. Biodiesel and other biofuels have a wide range of potential feedstocks, and numerous additional supply chain factors impact the emissions intensity of biodiesel. In order to effectively track our state's emissions, it will be necessary to understand the different emissions profiles of biodiesel and require biodiesel blending with the lowest emissions. Beyond the 2030 biodiesel blending mandate, there will need to be solutions for fully decarbonizing oil heating by 2050.

Continue to abandon leak-prone gas pipes and pursue non-pipe alternatives

Public Utilities Commission Docket No. 5210, "National Grid's FY 2023 Gas Infrastructure, Safety and Reliability (ISR) Plan," contains the Leak Prone Pipe Replacement Program which replaces leak-prone gas mains throughout the Rhode Island gas distribution network. Since the program's beginning in 2012, 537 miles of leak-prone pipe have been replaced and an additional 951 miles are expected to be completed by the program's end in 2035.

While the avoidance of methane leaks along the gas system is extremely important to reducing our state's emissions, the efficacy of the Leak Prone Pipe Replacement Program, in light of the goals of the Act on Climate, needs to be evaluated. Gas mains that are replaced through this program have an expected lifespan between 50-100 years, locking in gas infrastructure well beyond the target date for an emissions-free state. Currently, there are extremely limited supplies of decarbonized gases, and the ratepayer cost impacts of future decarbonized gas supplies must be considered. It would be imprudent to continue to reinforce and expand gas infrastructure that could not be easily and affordably decarbonized by 2050. Therefore, in the coming years, more emphasis should be placed on non-pipes alternatives (NPA). NPA seeks alternative ways of providing thermal service to Rhode Islanders, rather than expanding and enforcing the fossil gas network. The gas utility has already formed a working group to discuss developments in NPA.

Continue to pursue solutions to reduce emissions from solid waste

Waste streams, such as landfills and water treatment facilities, produce highly penetrative greenhouse gases that result from the breakdown of biological material. If not captured, these greenhouse gases are released directly into the atmosphere and contribute to global warming. One method of decreasing direct emissions from waste is to capture these gases and use them as a source of renewable gas.

The future of the state's solid waste streams should be considered in the context of thermal decarbonization opportunities as well. There are numerous technologies that could be explored, but the climate and environment impacts must also be critically examined.

Future of the gas distribution system

Just over half of Rhode Islanders are connected to the gas system for heating, cooking, and various other household appliances. Gas is also used for high-heat industrial processes. At this time, Rhode Island is supplied with fossil gas that, while cleaner than other fossil fuels like oil and coal, still emits greenhouse gases and contributes substantially to climate change. The gas system in Rhode Island relies on extensive physical infrastructure in the form of pipelines and supporting facilities. Pipelines and other gas infrastructure have been, and continue to be, built with decades to centuries-long time horizons. There is an urgent need to reconsider the existing gas infrastructure and planning in our state to avoid burdening consumers with the cost of stranded fossil gas assets, as the state transitions to carbon neutrality.

In August 2022 the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG, "Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate."[88] This docket will serve as an important first step in beginning to plan for the gas system's transition to carbon neutrality. There are many options for decarbonizing the thermal sector, and as the HST Report notes, it is unlikely that one single technology will prevail. Instead, to optimize costs and emissions reductions, a mix of solutions will need to be pursued. Other states are looking to transform their gas systems to work cohesively with a mix of decarbonized thermal technologies. In light of the Act on Climate, it will be important to engage in a very robust planning process that ensures a viable future for the thermal sector with a mix of different technologies. The utility company is uniquely positioned to tackle large decarbonization challenges and substantially help move the state toward our emissions reduction goals.

Begin developing a renewable thermal standard

Similar to the recently enacted 100% Renewable Energy Standard, the state should begin to plan for a renewable thermal standard to phase thermal emissions down at intervals that align with the Act on Climate Mandates. The results of Docket 22-01-NG "The Future of Gas" may provide a good foundation to begin planning for such a standard. Additionally, other states with drafted renewable thermal standards could be looked to for best practices and guidance.

Table X. Summary of Remaining Recommendations for the Thermal Sector from Select Recent and Relevant Studies

Report Title	
Status	Recommendation
Heating Sector Transformation Report	
Priority action[89]	Ensure: Increase efficiency and reduce carbon content of all fuels to zero over time – ensures progress no matter which technologies are used
Priority actions[90]	Learn: Data collection, R&D, pilot projects to understand technologies, infrastructure, and customers
Underway[91]	Inform: Educate stakeholders – customers, installers, policy-makers – about pros and cons of options, system interactions, etc.
Priority Action[92]	Enable: Facilitate deployment with incentives; target natural investment opportunities; align regulation, rules, codes; expand workforce
Priority Action[93]	Plan: Expand planning horizon; develop long-term, high-level contingency plans now (don't commit yet) and use to guide near-term policy

[88] https://ripuc.ri.gov/Docket-22-01-NG

[89] Our priority action to begin the development of a renewable thermal standards is responsive to this recommendation.

[90] Two priority actions are responsive to this recommendation: pursue district geothermal, and pursue hydrogen demonstration projects in coordination with the Northeast Regional Hydrogen Hub.

[91] This recommendation is central to all new and upcoming thermal policies led by OER. For example, the High-efficiency Heat Pump Program will have a consumer and workforce education component.

[92] Priority actions to incentivize heat pumps, the future of gas docket, and planning for the renewable thermal standard are responsive to this recommendation.

[93] Future of gas docket and planning for the renewable thermal standard are priority actions responsive to this recommendation.

Energy Efficiency Market Potential Study	
Underway[94]	Electrifying oil and propane-based systems offers the bulk of the economic opportunity for heating electrification.

Climate and Food Systems

A food system represents the interconnected parts of the food supply chain such as production, consumption, distribution, processing, consumption and disposal, all of which creates greenhouse gas emissions and significantly impacts water resources and biodiversity. Globally, the food and agriculture sector are responsible for one-third of greenhouse gas emissions [95] 70% of water withdrawals and 60% of biodiversity loss. At the same time, climate change threatens our long-term food security due to greater frequency of extreme and erratic weather events which impact crop yield, disrupt natural ecosystems and weaken national and global food supply chains.

The majority of food-related GHG emissions comes from agriculture and land-use such as methane from cattle production, nitrous oxide from fertilizers on crop production and carbon dioxide from clear-cutting for food production as well as refrigeration and management of food waste. Despite all of those impacts and high emissions, according to the EPA, one-third of food produced in the United States is never eaten and, food waste is the single most common material in landfills. When food is wasted all the resources, land, fertilizer, capital and energy that went into producing it is wasted, too. In RI, 20% of waste that goes to the Central Landfill is food and organics waste [96] (2017).

Fortunately, food systems and agriculture hold potential to sequester greenhouse gas emissions while regenerating biodiversity and ecological systems. In fact, according to "Project Drawdown" scientists and policymakers estimate that the top two solutions to staying below the critical 2 degrees Celsius necessary for survival are reducing food waste and eating plant-rich diets [97].

In order to better understand the impacts of climate change on our food systems, the following actions should be considered:

1. Establish metrics to set a baseline of GHG emissions derived from the food system throughout the value-chain from agriculture/aquaculture to manufacturing, processing, consumption and food waste disposal. The EPA's GHG emissions by economic sector fails to capture the complexity of food systems-related emissions which is why it is imperative that we better align climate, land-use, transportation, and food systems planning and policies in Rhode Island. Most of the emissions related to food consumption are derived from activities outside of the state because we import some 95% of the food we consume. However, these Scope 3 emissions[98] will

[94] Current and upcoming heat pump incentive programs sponsored by OER and RIE incentivize the switch from oil and propane heating to efficient electric heat pumps.
[95] Cippa, Solazzo et al. *Nature* (2021)
[96] RI Food Policy Council (2017)
[97] Project Drawdown (2022)
[98] Scope 3 emissions are defined by the USEPA: "Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain. Scope 3 emissions include all sources not within an organization's scope 1 and 2 boundary. The scope 3 emissions

provide the greatest opportunity to drawdown emissions and should be considered as part of the Act on Climate mandates (ex: emissions related to the food purchased by State agencies for corrections and K-12 school meals could be quantified and goals could be set to shift menus towards more climate-friendly, nature positive foods for a healthy planet and healthy people)

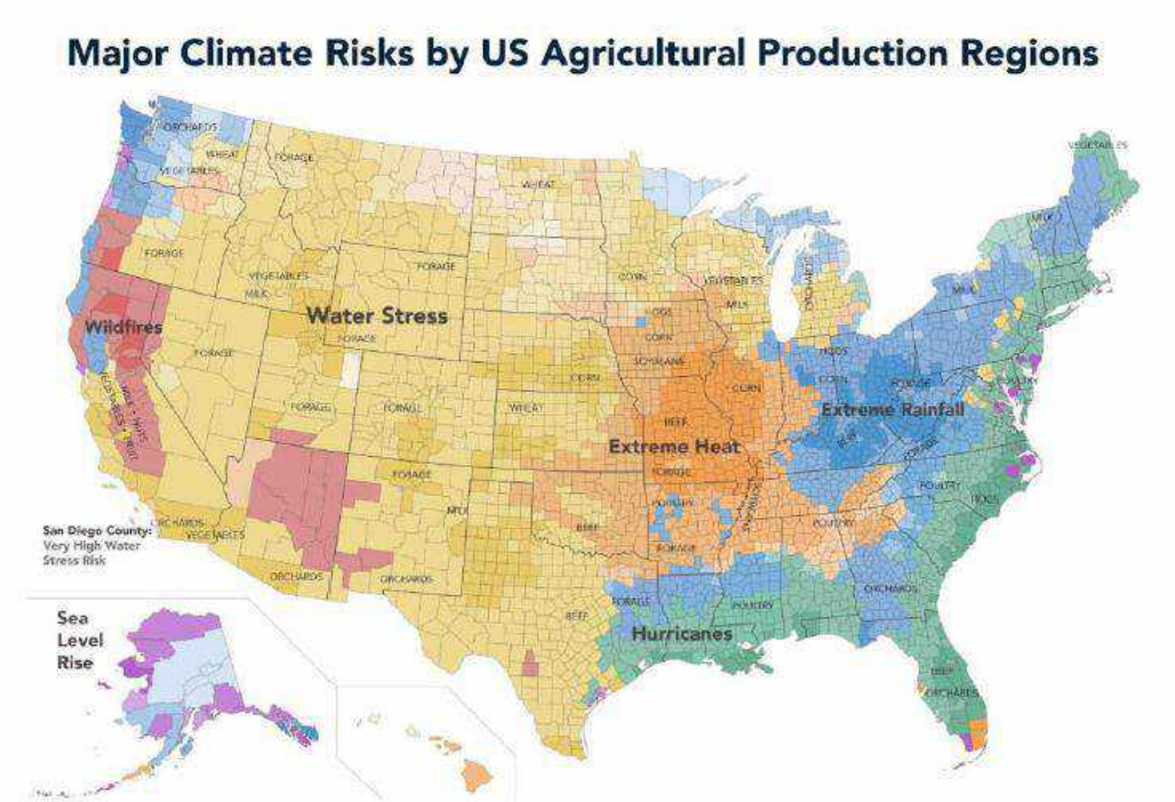
2. Quantify the current and potential carbon sequestration of our working lands and waters (e.g. agricultural lands, coastal areas zoned for aquaculture, etc.)

3. Evaluate policies for increasing food waste diversion and food recovery including more supports to help commercial waste generators comply with the 2017 "Food Waste Ban" and support municipalities with residential food/compost collection.

4. Support the development of the state's update to the 2017 food strategy "Relish Rhody" in order to strengthen regional food supply chains to better combat climate change disruptions to food producing and regions outside of New England

5. Explore alternative pathways to decarbonization which minimize trade-offs between renewable energy production and regional food production and harvesting.

for one organization are the scope 1 and 2 emissions of another organization. Scope 3 emissions, also referred to as value chain emissions, often represent the majority of an organization's total GHG emissions.



Source: *Every Country Has Its Own Climate Risks. What's Yours?*
https://www.nytimes.com/interactive/2021/01/28/opinion/climate-change-risks-by-country.html (2021)

Priority Actions to Address Climate Justice

As highlighted earlier in this report, since 2016, we've collectively seen vast growth in understanding about equity generally and climate justice specifically. This understanding should have already been a priority, and our level of understanding today is still deficient. However, we are making some progress. While the 2016 Plan omits mention of equity or justice, we have centered these concepts in the recommendations stemming from our more recent studies and we will integrate explicit consideration of equity and justice not only in this report, but throughout development of all future climate strategies and activities of the RIEC4.

In direct response to needs and calls for accountability, RIDEM and OER onboarded new staff in the fall of 2022 who will assist each respective organization to better understand and incorporate the needs of overburdened and underserved populations across the state. Bringing these voices to the front of the many conversations happening about mitigation and resilience will help to address community needs, build trust and incorporate new perspectives into Rhode Island's fight against climate change. This work began in 2022 with an inaugural 'Climate Justice Hour' in November 2022 with additional sessions planned in 2023 and beyond.

TABLE X: Summary of Priority Actions for Centering Climate Justice

Action	**Impact**
Create space for meaningful conversation – continue climate justice conversations in communities and with a new climate justice advisory board	Raises up new voices about climate justice and community needs into the RIEC4 and future climate plans, programs and policies
Better align work of RI's Health Equity Zones (HEZs) with the resilience and mitigation work being undertaken by RIEC4 agencies	Strengthens the efforts of the various HEZs to serve its members and provide tangible community benefits on issues related to climate change
Better coordinate state and local investments in urban tree programs	Provides health, social and environmental benefits for urban communities; increased tree canopies in RI's urban core
Provide technical assistance to communities for climate related issues	Allows communities to better address the climate/environmental/energy issues they have defined as priorities
Promote research into the impacts of climate change on overburdened and underserved communities	Provides a clearer understanding of direct impacts; better alignment of funding to address climate impacts and improve community resilience

Priority Actions Related to Land Use

Plants on our lands and in our oceans can absorb carbon dioxide, acting as a sink for emissions. However, removing natural elements of our land to develop our built environment (for roads, renewable energy resources and other uses) can take away the land's ability to sequester carbon dioxide. Beyond impacts on emissions – or climate change *mitigation* – how we use our lands is of critical importance in relation to climate change *adaptation* – our ability to reduce damages from and recover from the impacts of climate change like intense storms, extreme heat, and flooding.

These critical issues are being debated in RI, regionally in many states' climate plans and internationally. The Intergovernmental Panel on Climate Change (IPCC) published its Special Report on Climate Change and Land in August 2019[99]. It analyzes the existing science to date on how greenhouse gases are released and absorbed by land-based ecosystems, and the science on land use and sustainable land management in relation to climate change adaptation and mitigation, desertification, land degradation and food security. The findings are of great importance to decision-makers across the US and the world.

In terms of climate justice and equity, the way we use our lands will have a much bigger impact on the quality of life of Rhode Islanders than most other emissions reduction strategies. Land use policies that increase access to open public spaces and encourage the development of healthy communities while promoting the development of renewable energy resources is a balancing act RI must continue to explore in future legislation, regulation and policies.

[99] IPCC Report on Climate Change and Land Use (2019) https://www.ipcc.ch/srccl/

TABLE X: Summary of Priority Actions for Land Use

Action	Impact
Explore improvements to siting guidance and incentives that push solar development away from forests and agricultural lands towards previously disturbed sites	Streamline support for investments in renewable projects that minimize impacts on forest and agricultural lands
Identify a more stable and predictable funding stream for land conservation	Allow the state/municipalities/land trusts to develop longer-term land use protection strategies
Coordinate state and local investments in urban tree programs	Health, social and environmental benefits for urban communities
Expand existing programs that promote local agriculture	Increased local food security; reduce the carbon intensity of food
Promote research and policies that invest in regenerative agriculture practices	Allows agricultural lands to store more carbon to help mitigate the effects of climate change

Climate and Health

Climate change, health, and equity are inherently intertwined. Climate change acts as a risk multiplier, meaning vulnerable populations face more of its effects. Many of the environmental and social determinants of health, such as housing, proximity to traffic, tree canopy cover, and vulnerability to flooding, are related to climate. For this reason, improving community resilience is a key strategy to help keep a focus on equity and environmental justice. As incidences of heat-waves and flooding increase, we must address immediate health impacts and build resilience among Rhode Islanders.

Climate Change worsens the health effects from urban heat, flooding, severe weather and sea level rise, food and water borne diseases, vector-borne diseases, and poor air quality. Our efforts to cut greenhouse gasses, plant trees, reduce air pollution, build green infrastructure, and support healthy food systems will create huge gains in public health across the state. When we focus this work with equity and justice in mind, we will see the biggest gains among our most vulnerable populations. We should also use our decarbonization efforts to undo past harms and ensure that our youth are poised to take on the challenges of the work we know we need to do in our communities.

Extreme Heat

Extreme heat is an increasing threat across Rhode Island as the average temperature has already risen three degrees in the last century. Since 1980, there has been an average of 10 days above 90 degrees in the Providence area each summer, but already in the last several years, we have seen closer to 20 days. Extreme heat is the leading cause of weather-related injury and can lead to health harms such as cardiovascular events and dehydration. In the Providence area, studies have shown that some neighborhoods can be up to 12 degrees warmer on hot summer days. These neighborhoods also tend to stay warmer at night. In the last several years, the Department of Health (DOH) and the Department of Environmental Management (DEM) have teamed up to support urban forestry and better understand urban tree canopy across our cities.

Air Quality

Air quality also degrades when it is hot. Ozone is formed from air pollution and sunlight on hot days. While DEM measures air pollution and issues air quality alerts on high ozone days, it is the very localized, everyday emissions that we also must consider. For example, many schools and neighborhoods are close to heavy traffic and truck routes putting residents and children at a higher risk. Schools also lack proper air filtration and air conditioning creating poor indoor air quality. As spring and fall warms, learning suffers in hot classrooms. Asthma is also a large driver of school absenteeism and can affect learning. As we remove fossil-fuel burning appliances from homes and provide efficient air conditioning to urban families, the health of children will greatly improve as will their success in school.

Emergencies

During emergencies, people who are already vulnerable suffer the most. RIDOH has worked with senior living facilities to make sure they have shelter-in-place plans for their residents and adequate supplies during events. The Rhode Island Special Needs Registry allows those who need additional help to make sure they are prioritized during a storm. Restoration of power for those who need electricity for medical reasons is prioritized, but more can be done to help folks with assistance for back-up power and batteries for their medical devices. RIDOH is also working on supporting cooling shelters and community spaces that can serve as information centers and gathering places.

Mental Health

Mental health is affected by climate change in multiple ways. People who are taking certain medications are more prone to heat stroke and have a hard time regulating body temperature. Heat can also increase anxiety and levels of violence and can affect sleep and mental functioning. Extreme weather events also increase anxiety and can lead to post-traumatic stress when lives are disrupted. Working with communities on building social cohesion and supporting a local resilient economy can help people bounce back from disturbances faster. Working with youth on climate solutions lowers their sense of anxiety and gives them a place to be part of the conversation.

Health Care

The health care system should be an important part of implementing climate change solutions. Doctors and other health care providers are becoming more attuned to the effects of climate change on their patients. Medical students are asking to have climate change taught in medical school. Many health care systems are focusing on social determinants of health, the environment being one of them. The medical system also produces a large amount of waste and uses a large amount of energy. Hospitals should be part of the conversation about electrification and decarbonization as they provide critical community services. Sustainability efforts at hospitals are being supported more and more by medical professionals and should be part of state-wide efforts.

Looking Ahead to the 2025 Climate Strategy

When the legislature passed the Act on Climate and it was signed by Governor McKee in April of 2021, the sense of urgency for the State's response to climate change increased dramatically. Goals became enforceable mandates and clear priorities were set for equity, justice, and workforce development. These priorities were to be central to all our work on reducing emissions. Regular reporting, metrics, and dashboards, as well as strategic plans were required to ensure we stayed on track to meet our goals and clearly communicate status and progress. The *2022 Update* is the first of the plans required by the Act on Climate.

Beginning in September 2021, the RIEC4 initiated a comprehensive public involvement strategy to provide transparency and opportunities for engagement on the development of the *2022 Update*. The RIEC4 met more often – bimonthly versus quarterly – and held meetings across the state to allow more Rhode Islanders to participate in critical conversations about climate change. The RIEC4 held over 20 public listening sessions and workshops to gather public input for the *2022 Update*. The RIEC4 also worked closely with Governor McKee to make appointments to both the RIEC4 Advisory Board and the Science and Technical Advisory Board, started work to create a Climate Justice Advisory Group, and OER and DEM have both onboarded additional staff to assist with the state's numerous climate programs, including staff members in both agencies focused on climate justice. This *2022 Update* has been prepared to serve as a benchmark and updated foundation for the work ahead. We have reviewed the 2016 plan, reflected on the substantial work that has been done in Rhode Island over the past six years, and provided an interim path forward based on work being done across state government.

Much has changed in the world, the country, the region, and Rhode Island with respect to attitudes, actions, and science related to climate change since 2016. Key changes since 2016 include new emissions reduction targets directed by the 2021 Act on Climate; new learning from analyses, reports, progress on actions, and advances in science, technology, and business; emergency events leading to a renewed and stronger sense of urgency to act; and changing factors like new funding opportunities, renewable energy procurements, and changes in utility ownership.

The *2022 Update* reflects on past progress and identifies our priority short-term actions needed to stay on the right path to meet our 2030 emissions mandate, in hope these priorities will be well established by 2025. The 2025 Climate Strategy will then build out workplans for each sector to meet our mandates and set us on a viable path to reach net-zero emissions by 2050.

During the dialogs with stakeholders, it became clear that the development of the *2022 Update* was also an opportunity to reconsider and confirm technical aspects of modeling. Current emissions inventory processes, methodologies, and tools were reviewed in detail and, in many cases updated and modernized to use better local data. We also include explicit actionable recommendations for additional analysis in support of the development of the 2025 Climate Strategy.

In terms of progress and where we stand, Rhode Island's 2019 gross greenhouse gas emissions – the most recent inventory on record – are estimated to be 10.82 MMTCO2e. This level of emissions is 1.8% below emissions in 2016. Since 2016, electric power consumption emissions decreased by 28.0%, residential heating emissions increased by 13.5%, commercial heating emissions increased 8.8%, transportation emissions increased 8.8%, industrial emissions decreased 9.2%, agricultural emissions increased 39.2%, and waste emissions increased 14.2%.

Since 2016, the State has conducted several in-depth studies deepening our understanding of decarbonization activities and enabling actions. The *2022 Update* includes a list and summary of over a dozen major studies that either directly authored by state agencies or state-commissioned subject matter experts. These studies contain numerous data-driven and stakeholder-informed recommendations for future action that should be continually referenced throughout strategic climate planning. The list of studies in the *2022 Update* is not complete but is illustrative of the large and growing body of work we can rely on as we continue to reassess and refine our climate strategy.

Additionally, the Rhode Island General Assembly has debated and passed several bills addressing different aspects of our response to climate change. The most significant legislation was the 2021 Act on Climate, which set statewide, economy-wide climate goals that are both mandatory and enforceable.

In 2021, legislation updated the Biodiesel Heating Oil Act of 2013 to phase in higher percentages of biodiesel or renewable hydrocarbon diesel blended into home heating oil.

In January 2020, Executive Order 20-01 set a first-in-the-nation goal to meet 100% of Rhode Island's electricity demand with renewable energy by 2030. In 2022, the RI legislature passed a bill, subsequently signed by Governor McKee, to commit the state to 100% renewable energy by 2033.

In 2016, Rhode Island became home to the first offshore wind project in the nation with the successful installation of the 30 MW Block Island Wind Farm. In 2019, another contract for the 400 MW Revolution Wind was approved. In 2022, the legislature authorized procurement of up to an additional 1000 MW of power generated from offshore wind.

Obviously, action is needed to meet the upcoming emissions reduction targets that are now enacted in Rhode Island law. While the details, modeling, and balancing of these actions across the sectors of our economy will be done as part of the 2025 Strategic Plan, many actions are underway by several agencies, funded by both federal grants and state investments, and they must continue.

In the electric sector, we must take action to both consume less electricity and meet electricity needs using decarbonized energy resources. Critical to this will be meeting the 100% Renewable Energy Standard by 2033. The 100% Renewable Energy Standard is expected to grow demand for renewable energy resources; this, in turn, will require strategic investments in our electric grid to enable timely and efficient integration of these resources, as well as bolstering cost effective renewable energy within Rhode Island's portfolio through procurement of offshore wind. All actions must be considered within the larger fabric of policy objectives, and should be refined to improve affordability, equity, land use, and other policy objectives. This report outlines seven priority policies and actions for the electric sector to meet our goals and more detailed options, plans, and metrics will be developed as part of the 2025 Strategic Plan. Upcoming discussions on the use of smart meters and modernization of our electric grid will be critical to formulate state policies and investments moving forward.

In the transportation sector, priority actions must be taken to both consume less fuel and consume lower-emissions fuel. To consume less fuel, we can discourage high-emissions driving and encourage low-emissions mobility solutions. To consume lower-emissions fuel, we need to encourage electric vehicles and expand electric vehicle charging infrastructure. Critical to all this is the development and construction of a convenient and robust charging infrastructure across Rhode Island and pushing the adoption of more and more low-emission and zero-emission electric vehicles. Strategies outlined in the *2022 Update* those focusing on passenger vehicles, public transportation, and school bus transportation. More work is needed to develop a plan for commercial fleet conversion. Over the next five years, we can strengthen the groundwork for integrating climate into our investment decisions in transportation infrastructure and take action to incentivize lower-emissions mobility. The modeling to done in support of the 2025 Strategic plan will balance these options and provide us with the degree of implementation and penetration needed to meet our goals.

The thermal sector consists of emissions from all thermal processes, including space heating and cooling, high-heat industrial processes, refrigeration, cooking, and household activities such as clothes drying. Fossil fuels, electricity, and bio-based materials are all used as energy sources for thermal processes in Rhode Island. Our initial action on this will be a large state investment supporting the conversion of heating systems to heat pumps, moving from fossil-fuel based heating to electricity. An upcoming discussion on the future of natural gas in Rhode Island will also be very important to inform our strategies and plans for the building and heating sector. As Rhode Island makes significant investments in both housing and school construction, climate considerations must be incorporated into those design and construction plans.

With technical assistance funding from the US Climate Alliance, Rhode Island partnered with the Rocky Mountain Institute (RMI) and Acadia Center to undertake high-level greenhouse gas modeling focused on the near term 2030 reduction mandate (45% below 1990 levels). A high-level state decarbonization analysis was performed by the Acadia Center utilizing the RMI's Energy Policy Simulator (EPS). By modeling a short list of key policy scenarios as outlined in the report, it is projected that Rhode Island slightly misses the Act on Climate's 2030 reduction mandate. This is a very simple, preliminary model that verifies Rhode Island is moving in the right direction but is not quite at the point where we can be confident in our success. More scenarios must be considered, with input from a wide variety or experts and stakeholders, and the modeling needs to be further refined to develop and balance different implementation strategies to increase that confidence. That will be the crux of the 2025 Strategic Plan.

On that note, the RIEC4 will immediately turn attention to the 2025 Climate Strategy, which will include a set of "strategies, programs, and actions to meet economy-wide enforceable targets for greenhouse gas emissions" due by December 31, 2025. The 2025 Climate Strategy will be developed via a robust stakeholder process modelled closely on the process used for the *2022 Update* and will address areas such as environmental injustices, public health inequities, and a fair employment transition as fossil-fuel jobs are transitioned into green energy jobs. The 2025 Climate Strategy will be a comprehensive working document that will be updated every five years thereafter.

The public involvement strategies for the *2022 Update* were generally well received and effective in soliciting comments and feedback from a broad range of stakeholders. Thank you to everyone who participated in the listening sessions, attending our RIEC4 meetings, and for providing comment through the online portal. A huge change from 2016 is the degree of public engagement and interest, and it is clear that people want more - both in terms of more opportunities to participate and more action. Looking forward to starting the next process on developing the 2025 Strategic Plan, we will continue some of the best practices from this effort with a specific eye towards bringing in more voices to the conversation. In particular, our engagement with disadvantaged and underserved communities has just begun and there is much more work necessary to ensure that those voices are heard in our policy and program discussions. Similarly, we need to develop systems to effectively engage with municipalities and Rhode Island's business communities. Their voices and contributions will also be critical to meeting our greenhouse gas emissions reduction goals. Concurrently with these additional outreach efforts, we must expand our communications channels to effectively tell our story and get broader engagement across the State.

The agencies in the RIEC4 will focus on implementation of the action items outlined in this report. The RIEC4 will continue to work with the Advisory Board, as well as the Science and Technical Advisory

Board and Climate Justice working group, to refine policies and develop metrics and the public dashboard called for in the Act. The metrics and dashboard will show the progress made and the status of our efforts.

Discussions of identifying and allocating resources to these efforts will continue. The decarbonization and transition of our economy must be done carefully, and deliberately, to meet the goals set forth in the statutes. This will require both internal and external expertise and support for all the agencies. In the near term, prospects for federal support in many areas looks strong, particularly from the federal Bi-Partisan Infrastructure Law and the Inflation Reduction Act. However, these federal funds will not provide complete support needed for our efforts and state funds will be needed.

We look forward with enthusiasm to working with all partners as we chart our path forward to implementing solutions and achieving the goals of the Act on Climate.

Appendix: Stakeholder Engagement

Summary

A goal from the outset of the development of this report was to prioritize stakeholder involvement to inform the priorities and actions outlined for next steps to meet the goals of the Act on Climate. Over the course of 12-months between November 2021 and November 2022, over 20 listening sessions and workshops addressed the following topics, and in many instances multiple sessions were hosted for each topic:

1. Scoping the *2022 Update*
2. How to Define Net-Zero Emissions by 2050
3. Understanding RI's Greenhouse Gas Inventory Process
4. Priority Actions for the Electric Sector
5. Priority Actions for the Transportation Sector
6. Priority Actions for the Thermal Sector
7. Priority Actions for Land Use
8. Health & Climate
9. Buildings & Climate
10. Food Systems & Climate
11. Climate Justice

The first seven sessions listed above are further summarized in the following pages of this appendix. We highlight issues heard from participants and actions identified to help the state meet its near-term climate goals.

In addition, we further highlight the issues of health and climate, buildings and climate, food systems and climate, and climate justice in special sections in the report. A copy of the slides from these sessions can be found online at: https://climatechange.ri.gov/act-climate/attend-event [100]

Throughout the development of this report, the RIEC4 utilized an online comment portal called Smart Comment to collect and review additional comments submitted by interested parties. Over 390 sets of comments were received from November 2021 through early December 2022. The vast majority were submitted on behalf of individuals, with additional sets of comments submitted on behalf of local/regional organizations active in RI's climate change conversation. Additional public comments were offered verbally at RIEC4 meetings between December 2021 and December 2022.

[100] Note: The November 'Climate Justice Hour' did not utilize slides. It was intended to be a conversational session. Additional 'Climate Justice Hours' will be held in 2023 and beyond to ensure continued conversations with communities disproportionately impacted by environmental and climate burdens.

Scoping the 2022 Update Sharing Session (#1) Stakeholder Appendix

The 1st series of public sharing sessions was held in November 2021 and discussed the scope of the *2022 Update to the 2016 Greenhouse Gas Emissions Reduction Plan*. During this first public sharing session, 89 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the clean energy industry.

The goal of the discussion was to reach consensus on the scope of the *2022 Update* and was framed by four discussion points to generate participation and input from all groups represented.

The first discussion point was for each attendee to describe their objectives for the update. After attendees expressed their opinions on the matter, the following objectives were recorded: be responsive to the 2021 Act on Climate, center equity and be developed using a meaningful public participation process, leverage lessons learned since 2016, build a foundation for the *2025 Climate Strategy*, reconsider and confirm technical aspects of modeling while promoting reliance and being action oriented, and focus on near-term actions to achieve the 2021 Act on Climate's 2030 mandate.

The next discussion point was focused on the major changes and lessons learned since the last Greenhouse Gas Emissions Reduction Plan was published in 2016. Some of the changes that were highlighted include new learning from analyses, reports, progress on actions, and advances in science, technology, and business over the last few years. There was also a mention of lessons learned from intense weather events that renewed a sense of urgency to act on the issues posed by the changing climate.

Given these objectives and changing conditions, attendees collaborated with one another to come up with updates to specific components of the *2016 Greenhouse Gas Emissions Reduction Plan*. This scope includes technical updates, updates to pathways, policy, and implementation strategies, as well as specific action items. The technical updates include modernizing the greenhouse gas emissions reduction targets to comply with the 2021 Act on Climate, defining the goal of reaching net zero emissions by 2050, and review modeling to ensure the 1990 baseline is sound and the data and modeling assumptions are reasonable. Under the update pathways, policy and implementation strategies, there were a few more recommendations. This included providing progress updates, as well as coordinating emissions sectors with policies from the *2016 Plan*, adding and refining policy and implementation strategies from more recent studies that also comply with the 2030 mandate, and consider new funding opportunities. There were also recommendations to review the entire *2016 plan* with equity appropriately centered, identify and engage key stakeholders, develop a climate dashboard that tracks progress on community-prioritized outcomes, and identify and address the prerequisite needs or the *2021 Climate Strategy* and preview the work ahead.

The last discussion point was centered around which stakeholder groups should be included in future conversations, and attendees were encouraged to help connect the project team to their contacts within these groups and to continue to recommend stakeholders with whom to engage.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Defining 'Net-Zero Emissions by 2050' Sharing Session (#2) Stakeholder Appendix

The 2nd series of public sharing sessions was held in January 2022 and discussed how the 2021 Act on Climate's ultimate mandate of 'net-zero emissions by 2050' should be defined. Over the span of two identical sessions, held on January 11th and 13th, 102 people participated from a range of stakeholders including, interested individuals, environmental advocates, policymakers, and representatives of the clean energy industry.

The scope of the discussion was framed by three different prompts whose aim was to increase understanding surrounding considerations and preferences for how we define 'net-zero by 2050'. This was facilitated through a brief background information discussion before diving into the prompts.

The first prompt asked attendees which emissions should be included when defining the term 'net-zero emissions by 2050'. Attendees generally supported continuing to track the same four greenhouse gases already tracked by the IPCC and US EPA, which include Carbon dioxide, Methane, Nitrous oxide, and Fluorinated gases. A few concerns were raised including timeframes regarding global warming potentials, biogenic versus anthropogenic emissions, tracking for methane leakage from pipelines, considerations for land use changes, emissions from biodiesel and bioheat, the importance of consistency throughout states and with the IPCC, the role of education and messaging, developing mitigation strategies tailored for each type of emission, and prioritizing action.

The second prompt was centered around how we should net emissions. There were two net options given, one was net each greenhouse gas first and the second was to net MMTCO2e last by subtracting the sinks from the sources of MMTCO2e. Attendees were a bit more divided in this discussion, but the overall preference was towards netting MMTCO2e last, which is the current practice and capability. Some considerations that were raised included but were not limited to understanding the consequences of offsets versus sinks, the role of transparency regarding climate dashboards, and definitions to account for changes in technology and science.

The third and final prompt encouraged attendees to discuss the timeframe over which emissions should be netted. The current practice is to net emissions over an annual timescale, but attendees debated over whether annual or sub annual time frames would be more beneficial. It was roughly split 50/50 with slightly more attendees supporting the current annual timeframe but made sure to raise important points regarding the potential value in supplementing annual netting with sub-annual netting and considering the best timeframe for each type of sector. Other considerations included prioritizing action, focusing on reaching short term mandates, prioritize mitigating sources, highlighting success stories in conjunction with quantitative metrics, and identifying impactful near-term actions.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Greenhouse Gas Inventory Methods and Tools Sharing Session (#3) Stakeholder Appendix

The 3rd series of public sharing sessions was held in March 2022 and discussed the different greenhouse gas inventory methods and tools. During the session, 76 people participated from a range of stakeholders including, interested individuals, environmental advocates, policymakers, several state administration representatives, and representatives of the clean energy industry.

There were three objectives of the discussion: (1) provide a tutorial to improve understanding of how we inventory greenhouse gas emissions, (2) understand considerations and preferences for how / when we re-estimate greenhouse gas emissions changes due to land use, land use change, and forestry, and (3) understanding preferences for comparing apples-to-apples across years versus maintain an unchanging baseline against which to compare contemporary emissions.

The sharing session began with RIDEM expert Allision Archambault presenting a brief overview of how RIDEM inventories greenhouse gas emissions. After the overview, a facilitated discussion took place, using two discussion prompts that were meant to help attendees understand considerations and preferences for updating greenhouse gas emissions accounting.

The first prompt asked attendees what considerations they saw for how frequently Rhode Island estimates emissions reductions due to land use, land use change, and forestry (LULUCF). Attendees generally supported estimating emissions from LULUCF every five years, which is in line with Rhode Island's Comprehensive Climate Strategy beginning in 2025. There were some suggestions, including working to better understand trends and changes in LULUCF emissions and accounting methodologies. In doing this, we might strategically estimate emissions from LULUCF when certain indicators are met. The second prompt encouraged attendees to discuss considerations for how frequently we update the 1990 baseline. Three considerations were given: the first was to never change the baseline, the second was to update somewhere in between / strategically, and the third was anytime updated science is available. The attendees generally recommended that re-estimation should occur whenever major updates to climate science occur, such as those identified in IPCC Assessment Reports. Another recommendation made includes consideration of administration burden and costs when determining the frequency of update estimations.

Finally, attendees had an opportunity to voice other considerations for greenhouse gas emissions inventorying. The first included reiterating the importance of accurate accounting of and reduction of methane emissions, specially from the gas pipeline system. The second consideration was whether and how we track 'Scope 3' emissions, which are the emissions that result from activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Electric Sector Sharing Session (#4) Stakeholder Appendix

The 4th series of public sharing sessions was held in April 2022 and discussed the priority actions for the Electric Sector with regards to the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan*. Over the span of three identical sessions, 58 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the electric sector.

There were three objectives of the discussion: (1) provide a refresher on key recommendations from the 2016 Plan and update with the most relevant recent reports, (2) brainstorm actions needed over the next 1-3 years to set Rhode Island on a path to meet the 2030 mandate, and (3) understand preferences and considerations to inform how actions are prioritized.

Dr. Gill provided significant background information Rhode Island's electric sector emissions and how emissions would change if Rhode Island went 100% renewable. Some progress that was described included the extension of Rhode Island's Least-Cost Procurement statute, expansion of appliance and equipment energy and water efficiency standards, costs versus benefits measurement of pathways to decarbonize the electric sector in *The Road to 100% Renewable Electricity by 2030 in Rhode Island*, and two programs offered through the Renewable Energy Fund called ConnectedSolutions and Solar+Storage Adder Pilot Program that support the development of energy storage systems. Following the background information, several policy and programmatic recommendations were made, as well as planning, enabling, and equity recommendations.

The attendees then participated in a facilitated discussion, which allowed them to express their opinions on priority actions needed over the next 1-3 years within the electric sector to aid Rhode Island in meeting its goals for the 2030 emissions reduction mandate. The framework that was used in this segment fell under three categories: ensure decarbonization, enable decarbonization, and refining our actions. One clear priority action is to pass a 100% Renewable Energy Standard, and attendees also recommended bolstering energy efficiency and demand response programs, encouraging, and educating renewable energy practices in preferred locations, continuing to improve building standards and codes, modernizing the electric grid, and deploying smart meters. Some refining actions that were suggested by the attendees include improving affordability, improving equitable access to programs and public participation in program design, balancing land use priorities, and ensuring equitable investments in communities. Actions that would enable this include building relationships between customers and utilities, programmatic and process evolution, building community partnerships through regional collaboration, and systematic planning for energy storage.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Transportation Sector Sharing Session (#5) Stakeholder Appendix

The 5th series of public sharing sessions was held in May 2022 and discussed priority actions for the transportation Sector with regards to the *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan*. Over the span of three identical sessions, 54 people participated from a range of stakeholders including interested individuals, environmental advocates, policymakers, and representatives of the transportation sector.

There were three objectives of the discussion: (1) provide a refresher on key recommendations from the 2016 Plan and update with the most relevant recent reports, (2) brainstorm actions needed over the next 1-3 years to set Rhode Island on a path to meet the 2030 mandate, and (3) understand preferences and considerations to inform how actions are prioritized.

Dr. Gill provided background information on the greenhouse gas emissions from the transportation sector and said that most of the emissions come from on-road vehicles, which was one of the main focuses of the discussion. She also noted that there is an overall reduction in the transportation sector when (1) we consume less fuel and (2) we consume lower-emissions fuels. These pathways are what framed the facilitated discussion later in the presentation. Dr. Gill also reviewed Rhode Island's efforts to decrease carbon emissions in the transportation sector and named a few key areas of progress: encouragement of electric vehicle use in the state, electrification of the public transport buses, and enacting more stringent air regulations. In relation to decarbonizing the transportation sector, Dr. Gill highlighted two key studies conducted since 2016 that provide meaningful templates and information for states to use. The *Clean Transportation and Mobility Innovation Report* and the more recent *Electrifying Transportation Report* both provided significant information on recommendations for creating a healthier environment through more updated an efficient transportation use.

The attendees then participated in a facilitated discussion, which allowed them to express their opinions on priority actions needed over the next 1-3 years within the transportation sector to aid Rhode Island in meeting its goals for the 2030 emissions reduction mandate. The framework that was used in this segment was split into two conversations consistent with the two pathways we must reduce emissions from the transportation sector: reducing fuel consumed, and consuming lower-emissions fuel. The priority actions included reducing high-emissions driving, increase low-emissions mobility, and refining our actions. To reduce high-emissions driving, attendees suggested making driving less attractive while making transit more attractive, consider lower-emissions biofuels, and enact stricter emissions regulations on vehicles. As a suggestion to increase low-emissions mobility, attendees recommended making active mobility more attractive, such as support for the Bicycle Master Plan. In terms of refining our actions, attendees suggested learning from others, as well as balancing climate impacts of transportation investments among other policy objectives such as safety. The second conversation prompted attendees to suggest priority actions to encourage electric vehicle usage as well as charging infrastructure availability. In terms of actions to encourage people to switch to electric vehicles, attendees suggested incentive programs with sustainable and substantial funding streams, as well as broadening incentive programs to include other modes or transportation such as e-bikes. Attendees also discussed requiring maintenance strategies and standards for charging stations for actions to expand electric vehicle charging. Finally, under the section titled "refining our actions" attendees recommended tailoring strategies based on use cases and needs, as well as integrating equity into program design.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Thermal Sector Sharing Session (#6) Stakeholder Appendix

The 6th series of public sharing sessions was held in June 2022 and discussed emissions reductions in the thermal sector. Over the span of three sessions, 47 people participated from a range of stakeholder groups including, interested individuals, environmental advocates, fuel sector advocates, policymakers, and representatives of the utility company. The scope of the discussion was framed by two guiding emissions reductions principles: to reduce our thermal sector emissions, we can, 1) consume less fuel, and 2) consume lower emissions fuel.

Throughout the three sharing sessions, stakeholders had a range of comments, including numerous ideas to both enhance existing mechanisms for thermal decarbonization and to push beyond current structures which would enable novel approaches to decarbonizing our thermal sector. Ideas for thermal decarbonization also loosely formed a timeline of when to pursue certain measures, starting with low-hanging fruit while simultaneously planning for larger-scale and more complex projects that are not yet feasible in the short term.

Building codes, workforce development, and the implications of various decarbonization pathways and regulatory frameworks on energy costs, were some of the most highly discussed topics. Numerous stakeholders see building codes as a powerful lever for lowering the carbon intensity of heating and cooling in buildings. Stakeholders would like to see stronger, more enforceable energy codes that require buildings to lower the amount of energy needed for heating and cooling, and to require technologies that will be carbon-free. Ensuring that Rhode Island has the labor force needed to construct and install technologies in buildings that meet ambitions efficiency standards and decarbonization standards is essential. Furthermore, stakeholders see a need to start planning for the emissions and price impacts of various decarbonization pathways that could be pursued. Several stakeholders argued that a mix of centralized and decentralized approaches will likely be needed to meet the Act on Climate mandates, and given the scale of these potential project ideas, and the significant potential impacts on costs to consumers, it is urgent to think about how to manage these scenarios.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Priority Actions for the Land Use Sharing Session (#7) Stakeholder Appendix

The 7th series of public sharing sessions was held in July 2022 and discussed how natural vegetation can absorb greenhouse gasses, resulting in lowering emissions, and how we use our land can also help adapt to a changing climate and build community resilience. Over the span of three sessions, 43 people participated from a range of stakeholder groups including, interested individuals, environmental advocates, land use advocates, policymakers and renewable energy. The scope of the discussion was framed by two guiding questions: what do we need to do to decrease emissions resulting from how we use and develop land? and; what do we need to do to increase the amount of carbon our land can sequester?

Throughout the three sharing sessions, stakeholders had numerous comments, including clarifying what policies are in place to reduce solar development of forests and agricultural land (e.g. redirecting solar development to previously disturbed sites), promoting transit-oriented development, adopting a no-net loss of forests policy, prioritizing forest management to increase sequestration, promoting reforestation, increasing available state funds for land protection (including agricultural lands), prioritizing urban trees, and the need for a broader state discussion to address competing land uses.

Solar development, no net-loss policies, agricultural land protection (including healthy sols), and forest conservation (both urban and rural) were some of the most highly discussed topics. Numerous stakeholders see the competition between renewable energy development and land conservation as one of the most pressing on-going discussions in Rhode Island related to climate change. Stakeholders would like to see more regulations and policies in place to prevent future forest loss. Several stakeholders argued that issues related to food security and organics diversion need to be considered as well.

A copy of the slides from this session can be found online at: https://climatechange.ri.gov/act-climate/attend-event

Technical Appendix: Energy Policy Simulator GHG Emissions Avoided Modeling Analysis

Technical analysis conducted by Acadia Center, in collaboration with RIDEM, was used to inform the estimates of avoided greenhouse gas (GHG) emissions associated with individual actions and the collective suite of actions described in previous sections of this report. Specifically, Acadia Center leveraged the Rhode Island Energy Policy Simulator (EPS) model developed by Energy Innovation and RMI. The EPS was originally designed at a national scale with the intention of discovering the most effective policies to decarbonize America's economy at the lowest cost and empower decision makers to find the best course toward a low-carbon U.S. economy. In recent years, state-level versions of the EPS have been publicly released in select states. The version that has been customized for Rhode Island, referred to as the Rhode Island EPS (RI EPS), is scheduled to be released in early 2023 and will serve as a free, open-source, peer-reviewed model that allows users to estimate climate and energy policy impacts through 2050 on emissions, the economy, jobs, and public health using publicly available data. Technical documentation associated the EPS, detailing the specifics of how the model works, can be found at: https://us.energypolicy.solutions/docs/.

The RI EPS uses a "base year" starting point of 2020 and then projects emissions out to 2050 under a pre-loaded "Business as Usual" (BAU) scenario that incorporates existing policy, scheduled power plant retirements, some improvement in building and transportation efficiency, and economic adoption of electric vehicles (EVs). It's important to note that, due to some methodological differences, the base year 2020 GHG emissions in the RI EPS likely will not match the 2020 Rhode Island GHG emissions inventory (to be released in December 2023). For this reason, the RI EPS is not intended to provide precise projections of how a specific suite of actions will impact future emissions in Rhode Island as measured by the state's official GHG accounting standards, but rather is intended to provide high-level insight by estimating approximate GHG emissions reductions trajectories for the state.

Actions that have already been formally adopted in state legislation – including Rhode Island's Renewable Energy Standard and Biofuel Heating Oil Act – are included in this BAU Scenario. Building off of this BAU scenario, Acadia Center leveraged input and data from various Rhode Island state agencies to develop a customized emission modeling scenario for the *2022 Update* with the intent of developing high-level, preliminary estimates of the GHG emissions avoided by 2030 from both 1) Individual actions in this draft plan and 2) The collective suite of actions in this draft plan. Evaluating multiple policies simultaneously through the RI EPS captures the interactive effects of these policies. Ultimately, the 2022 Draft Climate Plan Update Scenario details how actions outlined in this plan would reduce Rhode Island's GHG emissions in 2030 beyond the reductions already captured in the BAU Scenario.

The table below provides a list of the actions analyzed for GHG emissions reduction potential by Acadia Center using the RI EPS and briefly describes the analysis approach for each action. In some instances, the analysis approach is "bottom up": For example, estimating vehicle miles travelled (VMT) avoided in the year 2030 as a result of the collective suite of actions and programs outlined in Transit Forward RI 2040 to reduce VMT in the state. In other instances, the analysis approach is "top down": For example, setting an aspirational target of 15% of space and water heating demand in all buildings served by efficient electric appliances by 2030. For "top down" measures, the specifics of the policies and programs needed to achieve these aspirational targets will require further detailed conversation and analysis.

Table X: List of Actions Analyzed in the Rhode Island Energy Policy Simulator "Customized Emission Modeling Scenario for the 2022 Update" & Analysis Approach by Action

Action	Analysis Approach
Enact a 100% Renewable Energy Standard	In accordance with the Renewable Energy Standard, assumes 72% of total electricity generated to be from qualifying renewable energy sources by 2030 (on course for 100% by 2033). This action was incorporated into the RI EPS BAU projections as the policy is already formally adopted in legislation.
Increase Adoption of Electric Vehicles (Light Duty)	Assumes state adopts Advanced Clean Cars II Regulations, taking effect starting model year 2027.
Increase Adoption of Electric Vehicles (Trucks)	Assumes state adopts Advanced Clean Trucks and Phase 2 GHG regulations, taking effect starting model year 2027.
Increase Decarbonization of RIPTA's Bus Fleet	Assumes 17.7% of total RIPTA bus fleet miles are driven by EVs by 2030 based on estimated projections from RIPTA staff assuming 1) Three pilot Proterra buses in service; 2) R Line electrification; 3) Electrification of five Newport routes; and 4) Route 78 service electrification.
Expand RIPTA Ridership to Reduce Light Duty VMT	Assumes a 4.8% reduction in statewide single occupancy vehicle miles travelled (VMT) below 2020 levels by 2030 based on estimated projections from RIPTA staff assuming 1) Full funding for TMP implementation; 2) Sufficient labor resources (drivers, mechanics, etc.) to implement at recommended service levels; 3) Timely implementation of all new routes and span/frequency recommendations; 4) Ridership growth at estimated rates; and 5) Land use changes consistent with TCRP calculator assumptions.
Strengthen Building Energy Codes	Assumes continuous adoption of the most recent International Energy Conservation Code (IEEC) model energy code for residential buildings and continuous adoption of the most recent American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Standard 90.1 for commercial buildings for all code cycles falling between 2021 and 2030.
Increase Efficient Electrification of Building Space and Water Heating	Assumes achievement of 15% of space and water heating demand in all buildings, both residential and commercial, in the state being provided by efficient electric appliances (e.g., heat pumps) by 2030.
Increase Biofuel Blending in Heating Oil	In accordance with the 2021 Biofuel Heating Oil Act, assumes that a percentage of biofuel is blended into the heating oil supply at rates of 15% by 2024, 20% by 2025, and 50% by 2030. In accordance with the current RI GHG emissions inventory lifecycle emissions associated with biofuel production and biofuel combustion were not assumed to result in GHG emissions attributable to Rhode Island. This action was incorporated into the RI EPS BAU projections as the policy is already formally adopted in legislation.
Maintain Current Amount of Forested Land	Assumes that Rhode Island adopts a policy or set of policies that results in maintaining the existing amount of total forested land currently in the state (approximately 361,000 acres) through the year 2030. This is an increase in amount of forested land in 2030 in comparison to the BAU Scenario which assumes a 2.3% decline in 2030 levels of forested land relative to 2020 levels of forested land based on analysis conducted by RIDEM.