

Rhode Island Investigation into the Future of the Regulated Gas Distribution Business

Technical Analysis Report
Docket 22-01-NG

April 2024



Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our three practice areas: Climate Pathways and Electrification, Integrated System Planning, and Asset Valuation, Transmission, and Markets. The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

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The results and conclusions of this report are the responsibility of the study authors and do not necessarily reflect the views of others, including members of the Stakeholder Committee, Technical Working Group, or organizations that provided funding to support this report.

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Executive Summary

In the context of Rhode Island's Act on Climate ("the Act") that requires the state to achieve net-zero economy-wide emissions by mid-century, the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG ("the Docket") to investigate the effect of the Act on the regulated gas distribution business in Rhode Island. The PUC required Rhode Island Energy (RIE), the largest provider of gas and electric service in the state, to retain a third-party consultant to perform a Technical Analysis that identifies options to reduce emissions from the gas distribution system and to understand the implications of these options. RIE retained Energy and Environmental Economics, Inc. (E3) to identify and model decarbonization scenarios that comply with the Act and to draft a report summarizing the technical analysis findings and implications.

This report presents E3's independent findings from the Technical Analysis. The findings are informed by analysis of decarbonization scenarios compliant with the Act that were developed in close collaboration with a Stakeholder Committee and Technical Working Group formed by the PUC.

Decarbonization Scenarios

E3, in consultation with the Stakeholder Committee and with final direction and approval from the PUC, designed six economy-wide decarbonization scenarios that each present distinct pathways to achieving the Act's climate targets of 45% by 2030, 80% by 2040, and net zero by 2050, compared to 1990 levels:

- + A **High Electrification** scenario, designed to assess the impact of pursuing a full-electrification pathway that transitions Rhode Island away from gas infrastructure;
- + A **Hybrid Electrification with Delivered Fuels Backup** scenario, designed to assess the statewide impact of hybrid electrification while evaluating potential net benefits of avoiding gas infrastructure;
- + A **Hybrid Electrification with Gas Backup** scenario, designed to assess the statewide impact of hybrid electrification while leveraging existing gas infrastructure in the long term;
- + A **Staged Electrification** scenario, designed to leverage existing infrastructure and mitigate customer impacts in the near term while achieving long term electrification;
- + An **Alternative Heat Infrastructure** scenario, designed to assess how networked geothermal systems can support decarbonization in Rhode Island, while providing an alternative to gas investments;
- + A **Continued Use of Gas** scenario, designed to assess how existing gas infrastructure can support decarbonization, evaluating the effect of and potential limit to remaining fossil gas and renewable fuels.

In addition, E3 developed a reference scenario to evaluate the impact of existing policies and trends on emissions reductions in Rhode Island. The scenarios evaluate emissions reductions across all sectors of the economy, while holding key emissions reductions in non-heating sectors constant to allow for comparisons across heating sector transformations. Importantly, these scenarios are not forecasts and are not intended to pick a preferred solution. Instead, scenario analysis allows for the

identification of commonalities, differences, and key implications for near- and long-term planning that are meant to inform the Docket’s policy and regulatory discussions. The scenarios do not model economic consumer behavior that results in meeting the Act but are instead based on a “backcasting” approach that assesses the necessary actions to comply with the Act. The probability that consumer behavior will follow these necessary actions is not modeled within the scope of this work. Lastly, it is important to note that the decarbonization scenarios developed are not optimizations; instead, each scenario is meant to answer “what if” questions about the future of Rhode Island’s energy system, rather than determine the optimal – or least-cost – path to decarbonization.

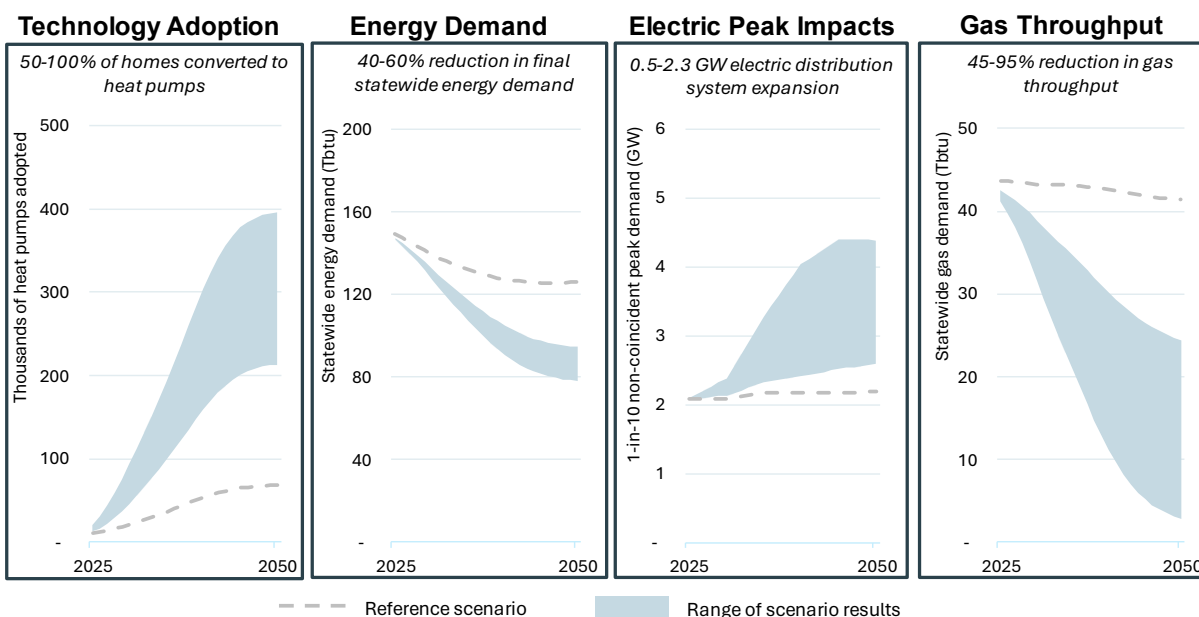
Technical Findings from Decarbonization Scenarios

Key technical findings from the decarbonization scenario analysis are shown in Figure 1 and described below.

Figure 1. Key Technical Findings from Decarbonization Scenarios

Emissions

All scenarios achieve the Act on Climate’s targets of **45% by 2030**, **80% by 2040** and net **zero by 2050** compared to 1990 levels



- + Emissions:** While existing policies and trends achieve 40% emissions reductions by 2030 compared to 1990 levels, additional mitigation measures are required to comply with the Act on Climate. All decarbonization scenarios modeled by E3 achieve the Act’s targets.

Sensitivity analysis demonstrates that scenarios with higher levels of renewable fuels¹ may have higher remaining emissions under alternative emissions accounting frameworks.

- + **Technology adoption:** Energy efficiency and building electrification are a critical component of gas system decarbonization. Across scenarios, between 50-100% of buildings are assumed to electrify to comply with the Act's targets. In the industrial sector, all scenarios include significant levels of efficiency and varying levels of industrial electrification, while leaving a role for pipeline gas for "hard-to-decarbonize" applications.
- + **Energy demand:** All scenarios see transformational changes in the way Rhode Island uses energy. Across scenarios, final energy demand decreases between 40-60% by 2050, primarily as a result of efficiency and electrification. Rhode Island will see an increased demand for renewable fuels, driven by the Biodiesel Heating Act in the near term and to comply with emissions targets in the long term.
- + **Electric system impacts:** By 2050 across scenarios, 40-60% of final energy demand is served by (renewable) electricity. The adoption of heat pumps and EVs lead to a need for significant system expansion, between 0.5-2.3 GW higher than today. Electric system peaks can be significantly mitigated through the use of hybrid backup systems or highly efficient networked geothermal systems.
- + **Gas throughput:** Gas throughput declines between 45-95% across scenarios, primarily as a result of efficiency and electrification. Scenarios that keep a role for gas heating (Continued use of Gas, Hybrid with Gas Backup), see an increase in the use of renewable fuels.

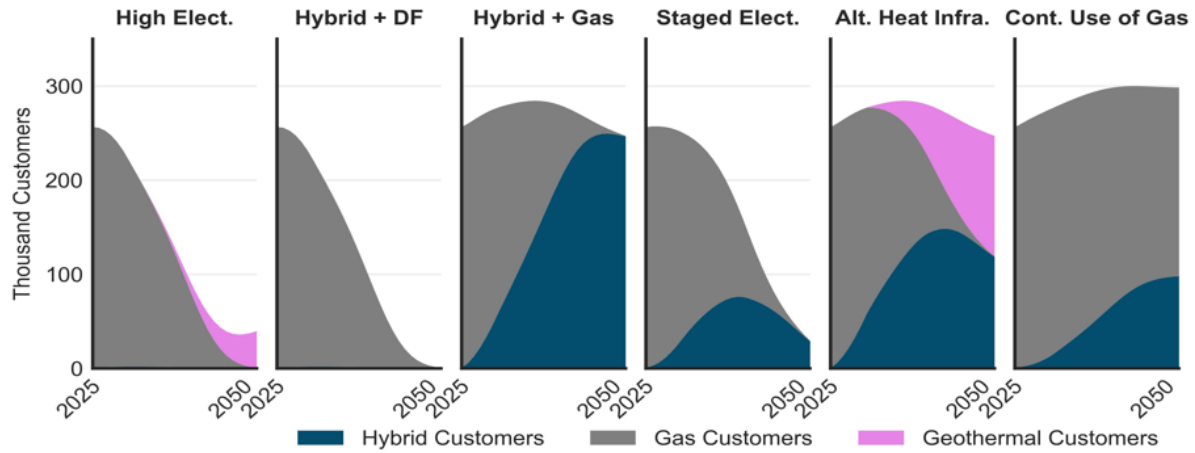
Role and Use of the Gas System

All scenarios imply a transformation of the role and use of the gas distribution system. Four out of six decarbonization scenarios see a significant decline in gas customers driven by electrification; two scenarios require a change in the way gas system is used (Hybrid with Gas Backup) or in the portfolio of gas that RIE would need to procure (Continued Use of Gas). At the same time, under the current regulatory framework, costs of the gas system are expected to rise as a result of planned levels of capital expenditures through the Infrastructure, Safety and Reliability (ISR) program. The replacement of leak-prone pipe (LPP) required in the next decade to ensure safe and reliable gas service, as well as expected reinvestments after the ISR program cause annual revenue requirement to nearly double by 2050 in a reference scenario. Although there are variations in RIE's revenue requirement across scenarios by 2050, the combination of reduced throughput and increasing system costs under the current regulatory framework results in rapidly escalating delivery rates for residential, commercial and industrial customers in nearly all decarbonization scenarios, leading to untenable long-term gas delivery rates for scenarios with high levels of customer departures. Absent changes in policy, \$2.6 billion in unrecovered rate base may still be present in 2050 in scenarios with high levels of customer departures.

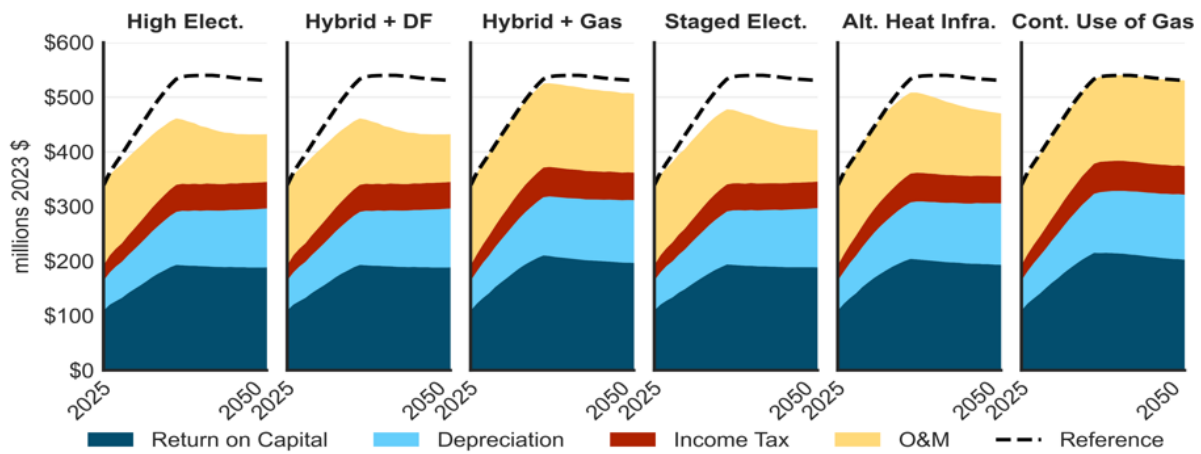
¹ E3 uses the term "renewable fuels" as an umbrella term encompassing a variety of emissions-compliant fuels. More context is provided in the main body of the report.

Figure 2. Gas Customers (Top), Revenue Requirement (Middle), And Residential Delivery Rates Across Scenarios (Bottom)

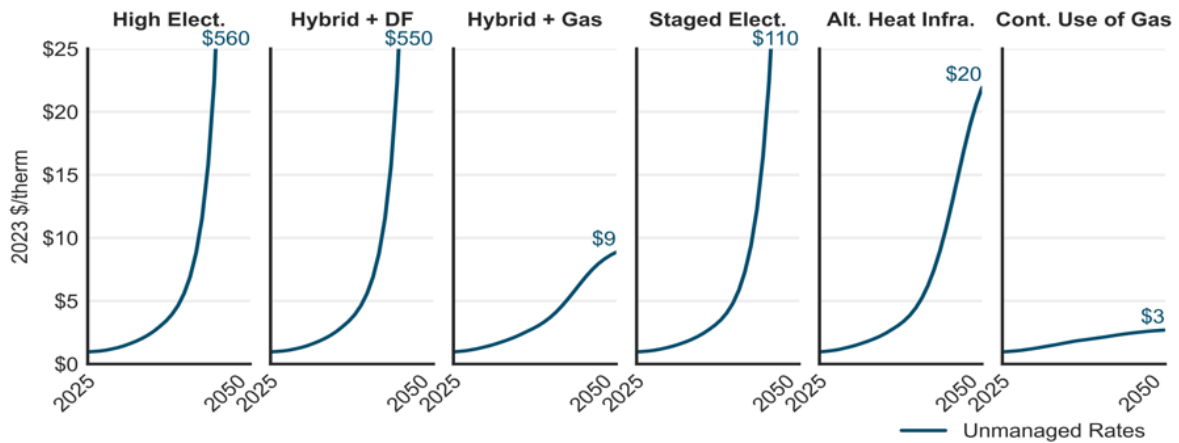
Gas Utility Customers



Gas Revenue Requirement



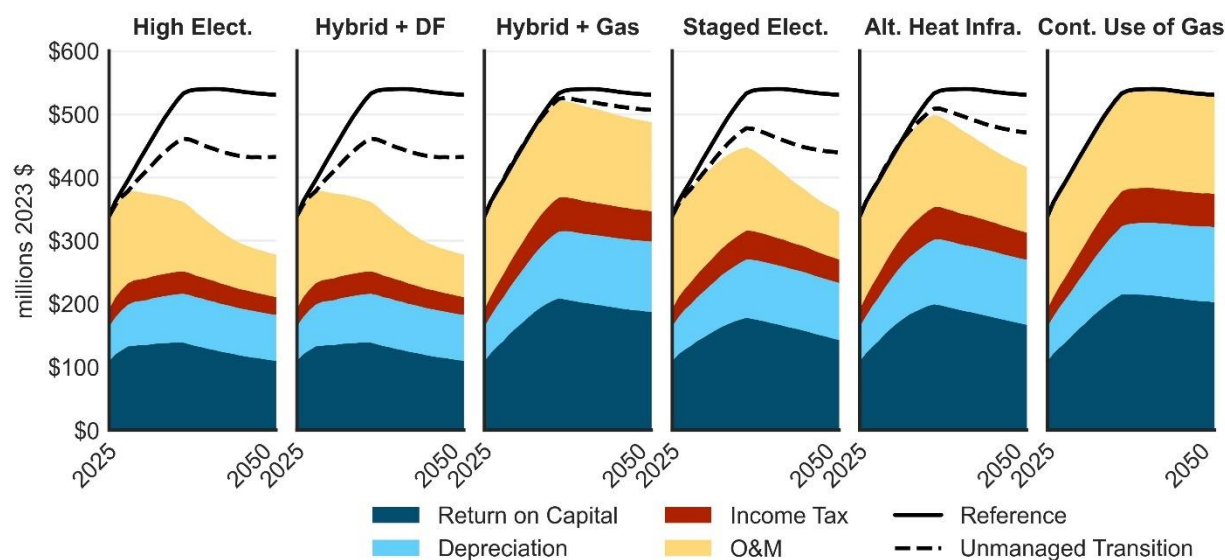
Residential Gas Delivery Rate



Impact of a Managed Transition

Through an illustrative analysis, E3 estimated the impact of a hypothetical managed transition, where electrification projects would occur in a targeted, neighborhood-scale manner, assuming these projects could avoid gas system reinvestment costs. This analysis found that *if* RIE could avoid up to 50% of capital replacements through targeted electrification, annual costs of the system could be reduced by up to 35% by 2050, while reducing potentially unrecovered rate base to \$1.5 billion. Although a managed transition could avoid annual system costs, the impact on delivery rates in scenarios with high levels of electrification is relatively small. However, the level of reinvestment avoidance assumed in this analysis is unprecedented, and much more research is required to understand the technical feasibility of this approach.

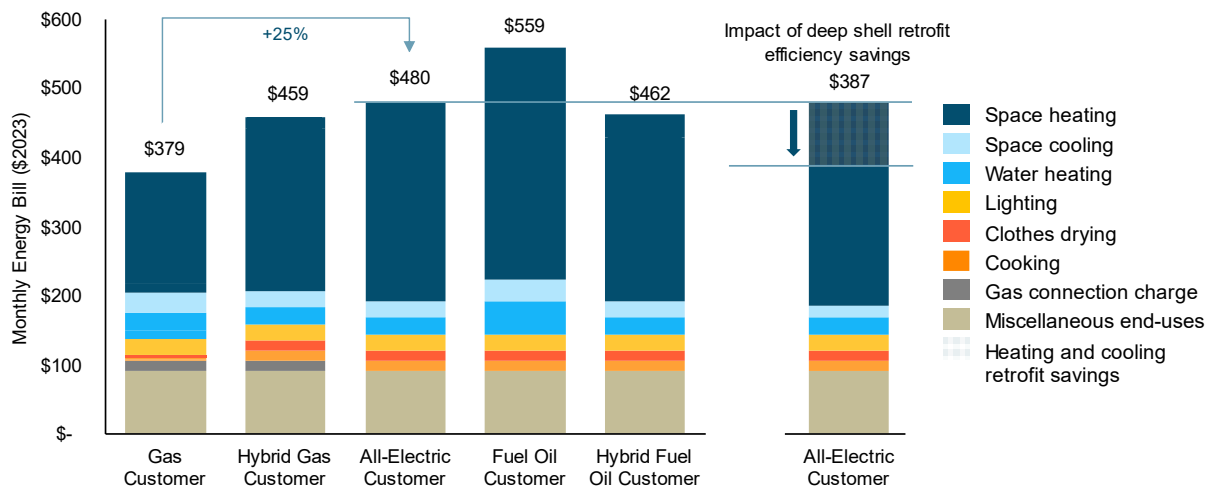
Figure 3. Revenue Requirement under a Managed Transition (note: based on illustrative cost avoidance assumptions)



Customer Implications and Affordability

Rhode Island currently has some of the highest electricity rates in the country. Today, as a result, gas customers transitioning to highly efficient all-electric heating will experience an approximately 25% increase in monthly energy bills. In addition, customers transitioning away from the gas system face significant upfront costs for electric appliances. Taken as a whole, the higher costs of electrification relative to natural gas today imply that additional programmatic and policy support is necessary to achieve the levels of customer electrification that was modeled to meet the requirements of the Act.

Figure 4. Residential Monthly Energy Bills in 2023



Counter to current conditions, electric heating becomes more cost-effective over time in comparison to gas heating in all scenarios, although the time of the “inflection point” differs. This outcome occurs because gas rate increases outpace electric rate increases as a result of two dynamics: 1) in scenarios where customers transition away from the gas system, the costs of the system are shifted to fewer remaining gas customers and 2) in scenarios where customers remain connected to the gas system, the commodity cost of gas increase through the procurement of renewable fuels.

Scenario Implications across Evaluation Criteria

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges across multiple evaluation criteria, as summarized in the table below. Overall, total resource costs fall within similar ranges across scenarios, but are lower for scenarios that leverage hybrid heating solutions and may further be reduced for scenarios that are able to avoid gas system reinvestments. All scenarios assume an increasing level of adoption of cleaner vehicles and home appliances that is significantly higher than it is today. It is important to note that scenarios that are able to avoid gas system investments through a “managed transition” require a change in how electrification technologies are adopted that is not modeled in detail in the Technical Analysis. Without interventions, customer adoption of home appliances is driven by choice and influenced by economic conditions. In a managed transition as modeled in the High Electrification, Hybrid with Delivered Fuels Backup and Staged Electrification scenarios, a top-down level of coordination is assumed where up to 3,000 customers adopt electrification technologies through a neighborhood-by-neighborhood approach, which has implications for customer choice. The likelihood that this type of coordinated strategy occurs is not modeled or assessed as part of the analysis and significant uncertainty exist around the feasibility and practicality of this approach.

In the scenarios as modeled, all decarbonized futures lead to long-term customer affordability challenges, both for customers adopting decarbonization solutions, as well as for customers who are faced with higher costs of the gas system as others electrify.

Scenarios with high levels of renewable fuels or networked geothermal systems (Alternative Heat Infrastructure, Continued Use of Gas) face high levels of cost uncertainty, partly due to the level of commercialization associated with these technologies. At the same time, both the use of renewable fuels and networked geothermal systems, as well as the use of hybrid heating technologies, significantly reduce the need for distribution system capacity upgrades that are required in a High Electrification scenario.

All scenarios may benefit from air quality improvements as the level of fuel combustion is significantly reduced to achieve the Act. These benefits are likely to be lower in the Continued Use of Gas scenario, which has the highest ongoing level of fuel combustion. Additionally, the Continued Use of Gas scenario is likely to require import of fuels from outside of New England compared to scenarios with higher levels of electrification that rely more heavily on in-region renewable electricity procurement. These scenarios additionally see potential positive impacts with regard to local economic development and workforce needs. Workforce needs on the gas system may be reduced over time, but these effects are likely to only occur in the long term.²

² Note: Workforce impacts are not quantitatively shown on Table 1, but are contextualized qualitatively in the report.

Table 1. Assessment of scenarios across evaluation criteria

Criteria	Representative Metric		High Electrifi- -cation	Hybrid w. DF Backup	Hybrid w. Gas Backup	Staged Electrifi- -cation	Alternat ive Heat Infra	Cont. Use of Gas
Total Resource Costs	Net Present Value between 2023-2050, incremental to reference		\$18-22 billion	\$15-21 billion	\$14-19 billion	\$15-20 billion	\$17-24 billion	\$16-26 billion
	Illustrative NPV savings if up to 50% of gas CAPEX can be avoided ³		-\$1.7 billion	-\$1.7 billion	-\$0.1 billion	-\$0.7 billion	-\$0.4 billion	-\$0.0 billion
Customer choice	Annual no. of targeted electrification customers (2035)	Un-managed	0	0	0	0	0	0
		Managed	~3,000	~3,000	0	~1,200	~700	0
Long-term affordability	2050 monthly total cost of ownership (TCO) for migrating customer		~\$700	~\$700	~\$700	~\$700	~\$800	~\$700
	2050 monthly TCO for non-migrating customer		> \$3,000	> \$3,000	~\$1,500	> \$3,000	> \$3,000	~\$700
	TCO “inflection year” for residential gas vs. all-electric customer ⁴		2036	2037	2037	2036	2036	2046
Air Quality Impacts	Change in statewide fuel combustion between 2020-2050 (%)		-85%	-82%	-81%	-85%	-82%	-65%
Reliance regional fuel supply	Total annual volume of renewable fuel required by 2050 (Tbtu)		11	15	15	11	13	33
Technology Readiness⁵	Likely range of Technology Readiness Levels required to achieve AoC		8-10	7-10	7-10	8-10	6-10	6-11
Electric System Expansion	Total increase in distribution system capacity by 2035 (GW)		1.2	0.5	0.4	0.5	0.4	0.2

³ Represents reduction in NPV if 50% of CAPEX can be avoided through managed transition, relative to the above row

⁴ “Inflection year” is defined as the point in time where the TCO for an all-electric heating customer is lower than for a gas heating customer, under the current regulatory framework.

⁵ E3 uses the Technology Readiness Level (TRL) scale defined by the International Energy Agency (IEA), where 1 refers to the lowest level of technology commercialization and 11 to the highest level of technology commercialization.

Scenario Commonalities and Additional Study Needs

Despite differences across scenarios in the transformation of the heating sector and associated use and role of the gas system, E3 distills several key commonalities across scenarios related to the gas distribution system as the state moves towards achieving the climate targets:

- + **Energy efficiency.** To achieve the Act, all scenarios rely on significant energy efficiency measures, such as building shell retrofits, that far exceed the state's rate of adoption today.
- + **Building electrification.** Building electrification is a significant component of gas system decarbonization across scenarios. Heat pump adoption levels in the next decade are 5-10 times higher than today's levels of adoption.
- + **Renewable energy generation and electric system expansion.** Achieving the state's 100% Renewable Energy Standard (RES) in combination with significant levels of electrification in all scenarios leads to increases in loads and peaks that are likely to require investment in and expansion of the electric grid.
- + **Affordability issues with decarbonization scenarios.** All scenarios rely on decarbonization measures that increase customer costs, especially with regard to gas-to-electric conversions. The adoption of decarbonization measures at the scale required to achieve the Act implies the need for policy development to mitigate these costs.
- + **Long-term impacts on gas customer bills.** All scenarios lead to an increase in rates for customers on the gas system, either through customers exiting the gas system or through the costs of renewable fuels. These results underline an important area of focus for the policy development phase of the proceeding.
- + **Opportunities for electrification of delivered fuels heating.** In contrast to gas customers, customers currently using delivered fuels as main source of heating, primarily located in the western part of the state, see a decrease in monthly energy bills with adoption of efficient electric heating, implying a near-term opportunity for emissions reductions.
- + **Significant uncertainty related to renewable fuels.** All scenarios rely on some volume of renewable fuels to comply with the existing Biodiesel Heating Act or the Act on Climate. The Technical Analysis demonstrates significant uncertainty associated with the availability, costs and efficacy of renewable fuels. This highlights the need for ways to mitigate uncertainty that can be addressed in the policy development phase of the Docket.

E3 identified four primary outstanding technical questions on the implementation and technical feasibility associated with decarbonizing the gas system that require further study:

- + **Technical feasibility related to a managed transition.** The assumptions E3 used to estimate the impact of avoided gas system costs are illustrative and not based on input from RIE. The magnitude of gas system cost avoidance assumed in this study is unprecedented. Additional research is required to quantify to what extent gas infrastructure projects can technically and cost-effectively be avoided through targeted electrification in Rhode Island.
- + **Technical feasibility related to networked geothermal systems.** Networked geothermal systems have the potential to reduce electric peak system impacts but, at the scales modeled in this study, come at an incremental cost to other electrification strategies. Additional research is needed to identify use cases where networked geothermal would see

a cost advantage relative to all-electric or hybrid electrification. Research is also required to understand the geological feasibility of these systems and to identify parts of the state where they can provide the highest level of benefit.

- + **Technical feasibility related to delivered fuels backup.** The Hybrid with Delivered Fuels Backup scenario demonstrates benefits with regard to electric peak mitigation while at the same time allowing for targeted electrification projects that may avoid gas system costs. However, the concept of using delivered fuels as a backup for winter heating needs, especially for customers currently connected to the gas system, is novel and requires further study, for example with regard to backup conversion costs, customer practicality and supply chain impacts.
- + **Workforce impacts.** A detailed study investigating the impacts of the Act on Climate on the workforce in Rhode Island, both related to the gas distribution system and to the broader clean energy transition, was beyond the scope of the Technical Analysis. Additional investigation into the jobs and skills necessary to facilitate the transformations outlined in this study is necessary to understand the challenges, opportunities and potential gaps associated with Rhode Island's workforce as the state transitions to a net zero economy.

1. Introduction

On April 14, 2021, Governor Dan McKee signed into law the Act on Climate (“the Act”), which mandates the state of Rhode Island to achieve climate targets of 45% greenhouse gas (GHG) emissions reductions by 2030, 80% by 2040, and net-zero by 2050, compared to 1990 levels. These targets represent mandatory, enforceable goals that position the state to address and mitigate the impacts of climate change, requiring a transformation of energy use across all sectors of the economy.

In the context of the state’s climate commitment, on June 9, 2022, the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG (“the Docket”) to investigate the effect of the Act on Climate on the regulated gas distribution business in Rhode Island.⁶ The final scope of the Docket was released in January 2023 and followed by a stakeholder process with the aim to gather “*clear recommendations from stakeholders on the future of the gas system in light of the Act*”.⁷

The scope required Rhode Island Energy (RIE) to retain a third-party consultant to perform a Technical Analysis that identifies options to reduce emissions from the gas distribution system and to understand the implications of these options. RIE retained Energy and Environmental Economics, Inc. (E3) to identify and model decarbonization scenarios that comply with the Act and to draft a report summarizing the technical analysis findings and implications.

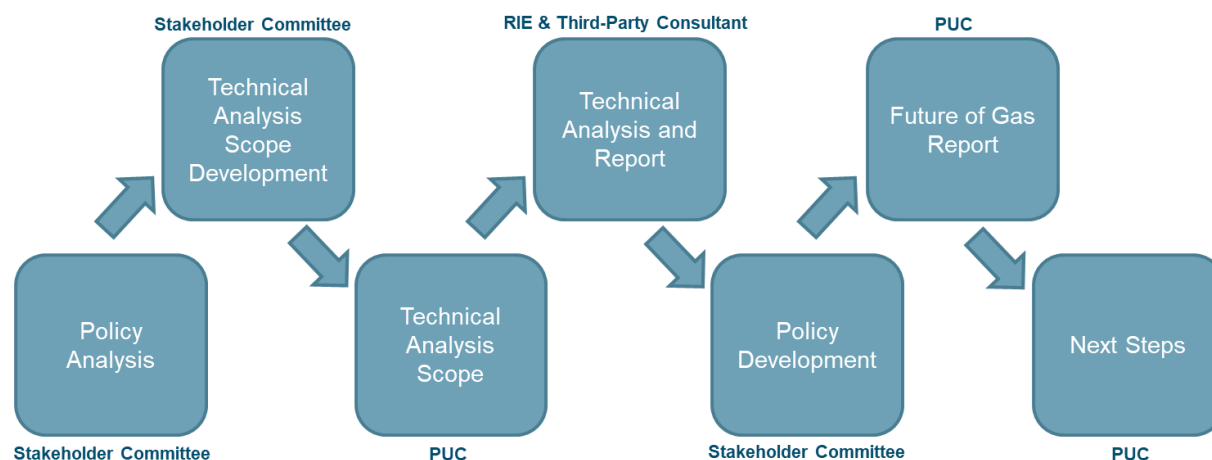
Docket Process

At the start of the Docket, the PUC established a Stakeholder Committee comprised of RIE, state agencies, business representatives, environmental organizations and consumer advocates to provide input and recommendations on the scope and outcome of various phases of the Docket. The PUC retained Consultant Apex Analytics, LLC. to facilitate the stakeholder process and guide the development of the Policy Development phase in the second half of 2024. An overview of the Docket’s process is provided in Figure 5 below.

⁶ State of Rhode Island Public Utilities Commission. Notice of Commencement of Docket. Docket No. 22-01-NG. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-08/22-01-NG-Notice_6-9-22.pdf

⁷ State of Rhode Island Public Utilities Commission. Proceeding Scope at 1. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/22-01-NG_FoG_Scope.pdf

Figure 5. Docket 22-01-NG Process



The Technical Analysis will be used by the Stakeholder Committee and the PUC in the Policy Development phase, with the aim of developing recommendations and next steps regarding the regulated gas distribution business in Rhode Island. As described in the scope, a Technical Analysis is “*necessary to create information useful to understanding what actions and options for emissions reductions are effective and to identify the potential benefits and costs of these actions and options*”.⁸ To validate foundational assumptions around modeling inputs and methodology, the PUC established a Technical Working Group (TWG) comprised of subject matter experts. The TWG provided input, feedback and recommendations with regard to E3’s modeling framework and assumptions. A total of 8 TWG meetings were prepared and facilitated by E3 and held on a bi-weekly basis between September 2023 and January 2024. An overview of TWG members is provided in Table 2. An overview of topics discussed with the TWG is provided in Appendix A.5.

Table 2. Technical Working Group Members (*TWG alternates, sharing 1 seat)

Name	Organization
Lee Gresham	Rhode Island Energy
Nicholas Vaz	RI Attorney General
Dean Murphy	Brattle, on behalf of RI Office of Energy Resources
Paul Roberti	RI Division of Public Utilities and Carriers
John Willumsen	RI Department of Labor & Training
Craig Pickell	Bullard Abrasives
Samuel Ross	NV5, on behalf of RI Energy Efficiency & Resource Management
Joseph Poccia	RI Department of Environmental Management
Mike Walsh*	Groundworks Data, on behalf of Sierra Club, Conservation Law Foundation
Ben Butterworth*	Acadia Center

⁸ State of Rhode Island Public Utilities Commission. Proceeding Scope at 2.
https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/22-01-NG_FoG_Scope.pdf

Scope of Technical Analysis

The scope of the Docket includes a list of comprehensive questions for the Technical Analysis to consider and address, summarized in the table below.

Table 3. Overview of Docket Questions related to Technical Analysis

Docket question	Docket sub questions	Addressed in Report
1. What infrastructure and non-infrastructure options exist for reducing emissions from the gas system?	a) Which have been explored in previous and current studies and which have not? b) What updates to the examinations in previous studies, including key assumptions, should be updated and/or considered for sensitivity testing?	Decarbonization Pathways Technical Results (Chapter 4) - Technology adoption levels, impact on gas and electric system
2. What scenarios for (all) sector-level emissions will allow the state to meet the emissions reduction mandates of the Act?	a) What is the appropriate baseline for the economy and for the gas system? b) In terms of different timing and extent of emissions reductions, what is the implication of these scenarios on the gas system? c) Does the feasibility of options for reducing gas system emissions change between these differences in timing and extent in these scenarios?	Decarbonization Pathways Technical Results (Chapter 4) - Emissions
3. What outputs of the Technical Analysis will inform the Policy Development phase?	a) What effects of decarbonization should be tracked between scenarios? For example, benefits, costs, rate impacts, inclusion and participation, reliability factors, impacts on other sectors, etc. i. What mechanisms of cost recovery should be examined? b) Which effects can be directly tracked, and which must be indirectly inferred by tracking related factors or proxies? c) From which points-of-view do we wish to track the effects of decarbonization? For example, the point-of view of society, the state, the EC4, residents, utility ratepayers, gas system ratepayers, etc. d) How much detail about how changes in the gas system will impact other sectors is necessary to model in order to answer key questions?	Decarbonization Pathways Assessment & Implications (Chapter 5)

4. What assumptions and inputs are critical to the outputs of the Technical Analysis?	a) Does current knowledge about these assumptions warrant testing alternative assumptions? b) Does current knowledge about these inputs warrant performing sensitivity analyses?	Decarbonization Pathways Technical Results (Chapter 4) – Sensitivity analyses
What statutory, regulatory, or stakeholder requirements and/or preferences exist that represent constraints on possible pathways for reducing gas system emissions consistent with the Act.		<i>To be discussed in Policy Development phase</i>
What final scenarios, including alternative testing and sensitivity ranges, should be included in RIE’s scope for the Technical Analysis the company will perform?		Scenario Development (Chapter 3)

About this Report

This Technical Analysis Report provides E3’s analysis of a set of decarbonization scenarios compliant with the Act that were developed in collaboration with the Stakeholder Committee. Through the analysis of decarbonization scenarios, E3 provides the findings and implications of options to reduce GHG emissions from the gas distribution system, addressing the questions raised by the PUC in the Docket as outlined above. Although the focus of the Docket is on the gas distribution system in particular, the Technical Analysis reviews the statewide transformations required in order to comply with the Act, to be able to understand the role of the gas system in achieving statewide emissions reductions.

This report was developed by E3 and provides E3’s independent assessment of the role of Rhode Island’s gas distribution system in achieving the state’s climate goals. E3’s findings are informed by discussions with and feedback from the Stakeholder Committee and TWG.

This report consists of 6 chapters. Chapter 2 provides an overview of energy and emissions in Rhode Island and the characteristics of natural gas distribution in the state today. Chapter 3 describes the approach towards the Technical Analysis used by E3, introducing E3’s modeling framework, scenario development and an overview of sensitivity analysis and evaluation criteria. Chapter 4 includes the key technical results of the decarbonization scenarios modeled by E3, distinguishing impacts on emissions, technology adoption, energy demand, the gas system and the electric system. Implications of these scenarios across evaluation criteria are further assessed in Chapter 5. Finally, chapter 6 provides an overview of key study takeaways and recommendations for further research.

2. Overview of Energy and Emissions in Rhode Island

Understanding the fundamentals of energy distribution in the state, as well as the composition of energy demand and, in particular, gas use by customers in Rhode Island, is essential to identifying the potential options to reduce emissions and the impact of these options. Both the gas and electric distribution system in Rhode Island are operated and maintained by a single utility, RIE. Delivered fuels, such as distillate fuel oil and propane, are supplied to homes and businesses by independent delivery service companies. These fuels—electricity, gas, and delivered fuels—are the primary fuels utilized for the purpose of heating in Rhode Island. Decarbonization efforts are expected to alter the heating fuel mix, their demand, and the impact on the distribution of fuels in the state in the next decades.

Energy Demand in Rhode Island

The State of Rhode Island counts 1.1 million inhabitants and consumed approximately 152 TBtu of energy in 2021.^{9,10,11} The Transportation sector is the largest consumer of energy in the state, accounting for 36% of state’s energy consumption, primarily relying upon gasoline and diesel to power on-road vehicles. The Residential sector is the second largest energy-consuming sector in Rhode Island, accounting for 31% of energy demand in 2021, mostly comprising of natural gas, diesel, and electricity used for building end-uses. The Commercial sector made up 21% of the state’s energy consumption in 2021, with consumption driven primarily by the use of electricity and natural gas. Industry was the lowest-consuming sector in Rhode Island, accounting for 13% of energy consumption in 2021.

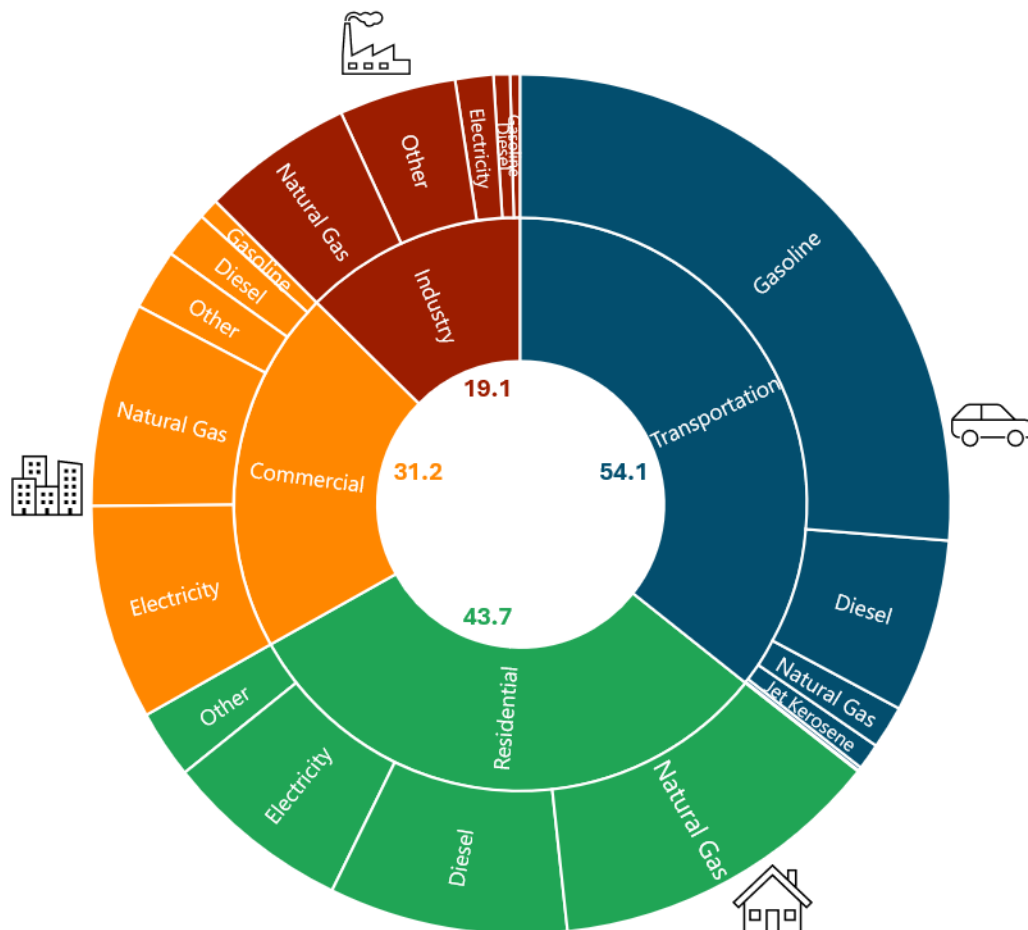
Approximately 23% of total energy consumption, or 41 TBtu, represents natural gas consumed for residential, commercial, and industrial purposes. Space and water heating are the primary uses for natural gas in the residential and commercial sectors, and plastics and metals-based durables manufacturing are the primary uses of natural gas in the industrial sector.

⁹ Energy demand total does not include electric power losses.

¹⁰ U.S. EIA State Energy Data System (SEDS). 2021. <https://www.eia.gov/state/seds/seds-data-complete.php?sid=US#Consumption>.

¹¹ The energy demand totals listed in this chapter are from 2021 as it is the latest year of publicly available data from SEDS.

Figure 6. Energy Consumption by End Use in Rhode Island in 2021 (TBTU)¹²



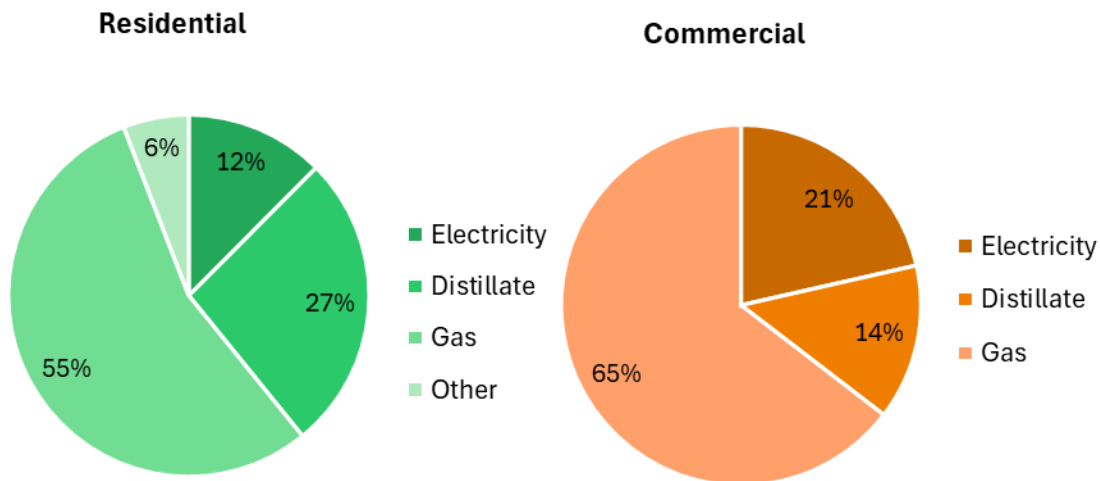
Residential and commercial heating demand is driven by the composition of heating fuels used in the state's building stock. In 2018, Rhode Island had over 400,000 occupied residential housing units and 302 million square feet of commercial building space.^{13,14} As shown in Figure 7, over half the building stock is heated by natural gas, while the remaining building stock is primarily heated by distillate fuel oil or electricity.

¹² U.S. EIA State Energy Data System (SEDS). 2021. <https://www.eia.gov/state/seds/seds-data-complete.php?sid=US#Consumption>.

¹³ Residential housing units come from the American Community Survey, U.S. Census Bureau. 2018. <https://data.census.gov/table?q=DP04&g=040XX00US44&y=2018>.

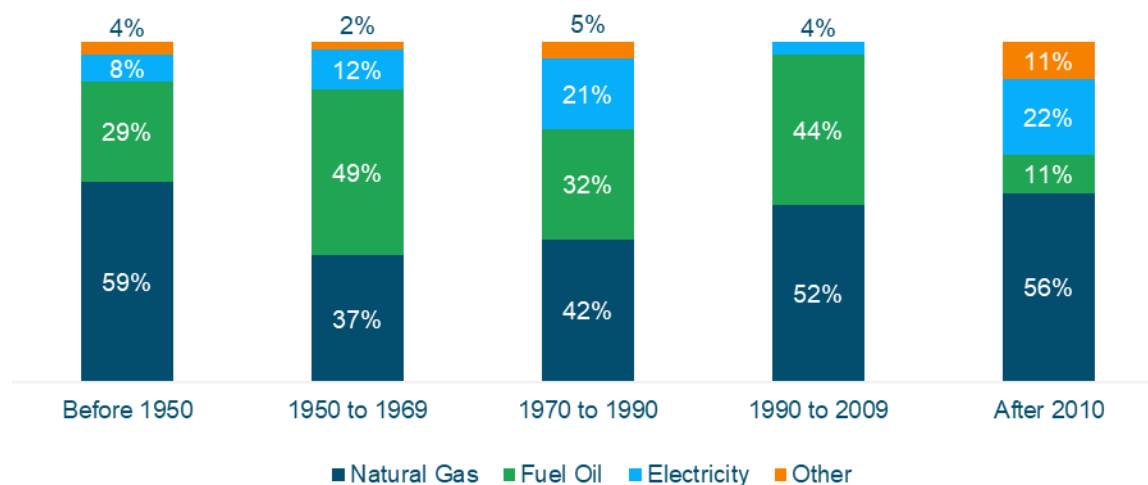
¹⁴ Commercial square footage comes from the Office of Energy Resources (OER) and Division of Public Utilities and Carriers (DPUC) Heating Sector Transformation Report.2020. <https://energy.ri.gov/HST>.

Figure 7. Space Heating Stock Share in 2021¹⁵



The primary heating system installed in residential buildings has varied over time, as illustrated by the heating fuels used by housing vintages (see Figure 8).¹⁶ Natural gas systems have been the primary heating system installed in most decades and have grown over time, whereas the number of distillate fuel oil systems declined in homes built after 2010. Electric heating, including less efficient resistance heating and more efficient non-resistance heating through heat pumps, has always made up a relatively small portion of heating systems installed in the building stock but has increased in market share since 2010.

Figure 8. Heating Fuel Use by Housing Vintage¹⁷



¹⁵ Other category includes LPG furnaces and wood stoves.

¹⁶ EIA, 2020 Residential Energy Consumption Survey (RECS)

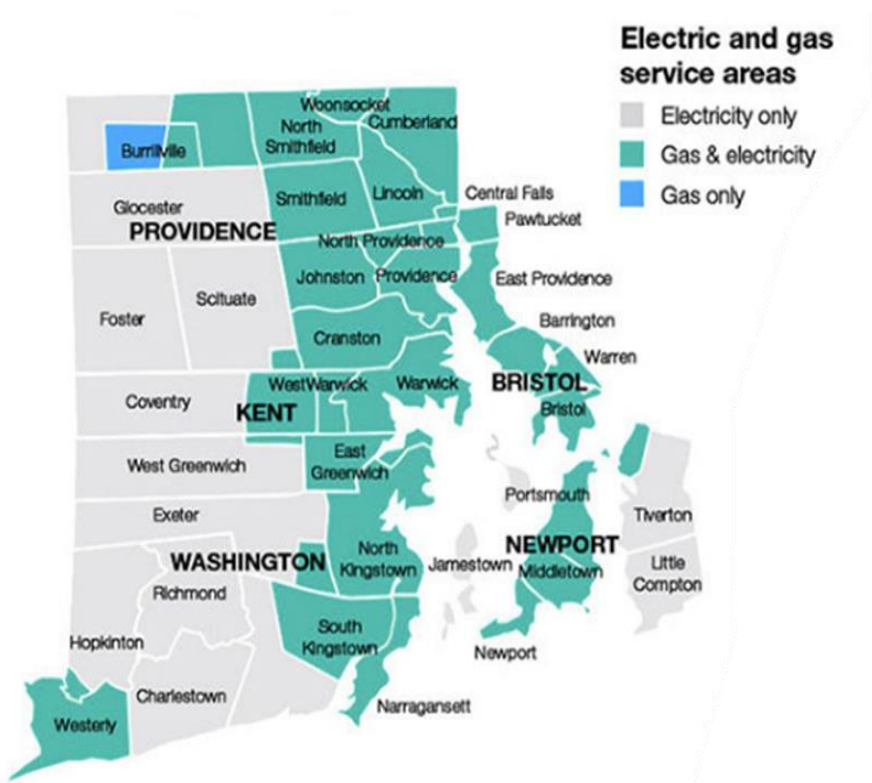
¹⁷ EIA, 2020 Residential Energy Consumption Survey (RECS)

Distribution of Energy in Rhode Island

RIE operates the electric and gas distribution systems in Rhode Island, providing electricity service to most of Rhode Island and natural gas service to parts of the state, primarily in the eastern half of the state (see Figure 9). RIE serves over 500,000 electric customers and over 270,000 natural gas customers.^{18,19} While the number of electric customers in the state has shown relatively limited growth over the past 10 years, mostly as a result of low levels of population growth, the number of gas customers has been rising steadily. From 2010 to 2020, RIE's gas customer base grew by approximately 0.9% annually, exceeding population growth and primarily reflecting fuel oil conversions to natural gas.²⁰

Unlike electricity and natural gas distribution, the distribution and sale of fuel oil and propane are not regulated. Most customers receive fuel oil and propane from local retail distributors, but some large commercial and industrial customers purchase fuel directly from wholesale distributors.²¹

Figure 9. Rhode Island Energy Service Territory²²



¹⁸ U.S. EIA State Energy Data System (SEDS). 2021. <https://www.eia.gov/state/search/#?5=126&6=134&2=220>.

¹⁹ U.S. EIA Natural Gas Data. 2024. https://www.eia.gov/dnav/ng/ng_cons_num_dc_u_sri_a.htm.

²⁰ Ibid.

²¹ Ibid.

²² RIE Gas Operations 101, 1/24/2024.

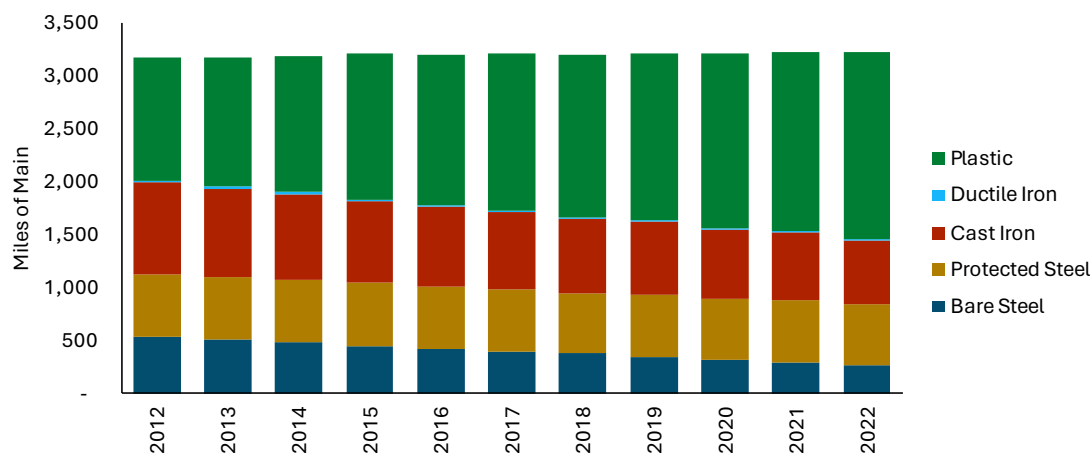
Natural Gas Distribution System

RIE operates the natural gas distribution system in Rhode Island and maintains approximately 3,200 miles of main and 194,000 service pipelines.²³ The company delivers approximately 40 Tbtu annually to a mix of residential, commercial, and industrial customers.²⁴

RIE's gas distribution system is a winter peaking system, following seasonal demand for space heating. To meet customer demand, RIE supplies gas via pipeline transportation, underground storage, and peaking resources. Most of the pipeline gas is supplied from the Algonquin and Tennessee interstate pipelines. Its underground storage resources include eleven injection-withdrawal storage assets with 65,200 dekatherms (Dth) of maximum daily withdrawal quantity.²⁵ RIE's peaking resources to meet the periods of highest customer gas demand include on-system liquefied natural gas (LNG) assets and portable LNG facilities, with 802,000 Dth of gross storage capacity and 119,000 Dth of vaporization capacity.²⁶

RIE maintains some of the oldest distribution pipeline infrastructure in the U.S.²⁷ Historically, a large part of the gas infrastructure was comprised of cast iron and unprotected steel, which is considered leak-prone pipe (LPP). Since 2012, RIE accelerated the replacement of LPP under its Infrastructure, Safety, and Reliability (ISR) program, with the primary goal to replace cast iron and unprotected steel pipe with plastic pipe. In 2012, 48% of the distribution system consisted of LPP. By the end of 2022, 27% of the system consisted of LPP, leaving approximately 860 miles of LPP still to be replaced.²⁸

Figure 10. Miles of Distribution Main by Material



²³ The Narragansett Electric Company Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan.

²⁴ Presentation by RIE during Docket Stakeholder Committee. RIE Gas Operations 101. 1/24/2024.

²⁵ The Narragansett Electric Company Gas Long-Range Resource and Requirements Plan for the Forecast Period 2022/23 to 2026/27, p. 67.

²⁶ The Narragansett Electric Company Gas Long-Range Resource and Requirements Plan for the Forecast Period 2022/23 to 2026/27, p. 23.

²⁷ Presentation by RIE during Docket Stakeholder Committee. RIE Gas Operations 101. 1/24/2024.

²⁸ Ibid.

Electric Distribution System

RIE provides electric service to over 500,000 residential, commercial, and industrial customers. The number of electric annual RIE customers has grown by approximately 0.3% annually from 2010 to 2020.²⁹ RIE's residential customers represent 88% of its customer count and 43% of its sales volume; RIE's commercial customers account for 12% of its total customers and 48% of its sales volume. Industrial delivery customers make up 0.3% of total customer count and 9% of its sales volume.³⁰

RIE's electric distribution infrastructure includes over 6,000 miles of distribution lines, 420 feeders, and 60 substations.³¹ Under Rhode Island's Renewable Energy Standard (RES), retail energy suppliers, including RIE, must procure enough renewable electricity to meet 100% of their customers' consumption by 2033, or pay an alternative compliance penalty.³²

In recent years, Rhode Island has seen a significant increase in the adoption of distributed energy resources (DERs), including solar installations, electric vehicle (EV) charging stations, and battery storage systems. RIE makes budget proposals for grid investments to support load growth and the changing demands of electric customers through annual ISR filings with the PUC.

Currently, RIE's electric system is summer peaking, designed for a peak demand of approximately 2,000 MW and an average demand of 1,000 MW. The all-time highest peak demand was 1,985 MW in August 2006.³³ Over the next 15 years, the company expects the annual peak to increase by approximately 0.2% primarily due to load growth from electrification.³⁴

Delivered Fuels

Fuel oil and propane are used by about one third of Rhode Islanders for space and water heating in buildings, meeting almost 40% of Rhode Island's heating demand.³⁵ The majority of these delivered fuels customers are located in the western part of Rhode Island where RIE does not provide gas service. Fuel oil and propane are shipped to Rhode Island via six marine import terminals in East Providence, Providence, and Tiverton and then delivered by truck to end-users.³⁶

Emissions in Rhode Island Today

The latest Rhode Island GHG Inventory was released in October 2023 and published data on 2020 emissions levels in the state. In 2020, Rhode Island emitted approximately 9 million metric tons of carbon dioxide equivalent (MMTCO₂e), representing an economywide emissions reduction of 20%

²⁹ U.S. EIA State Energy Data System (SEDS). 2021. <https://www.eia.gov/state/search/#?5=126&6=134&2=220>.

³⁰ U.S. EIA State Energy Data System (SEDS). 2021. <https://www.eia.gov/state/search/#?5=126&6=134&2=220>.

³¹ "The Narragansett Electric Company Electric Infrastructure, Safety, and Reliability Plan FY 2023 Proposal Book 1 of 2."

³² P.L. 2022, Ch. 218, § 1, effective June 27, 2022; P.L. 2022, Ch. 226, § 1, effective June 27, 2022

³³ Narragansett Electric Company, 2021 Electric Peak (MW) Forecast, 15-Year Long-Term, 2021 to 2036, at p. 4.

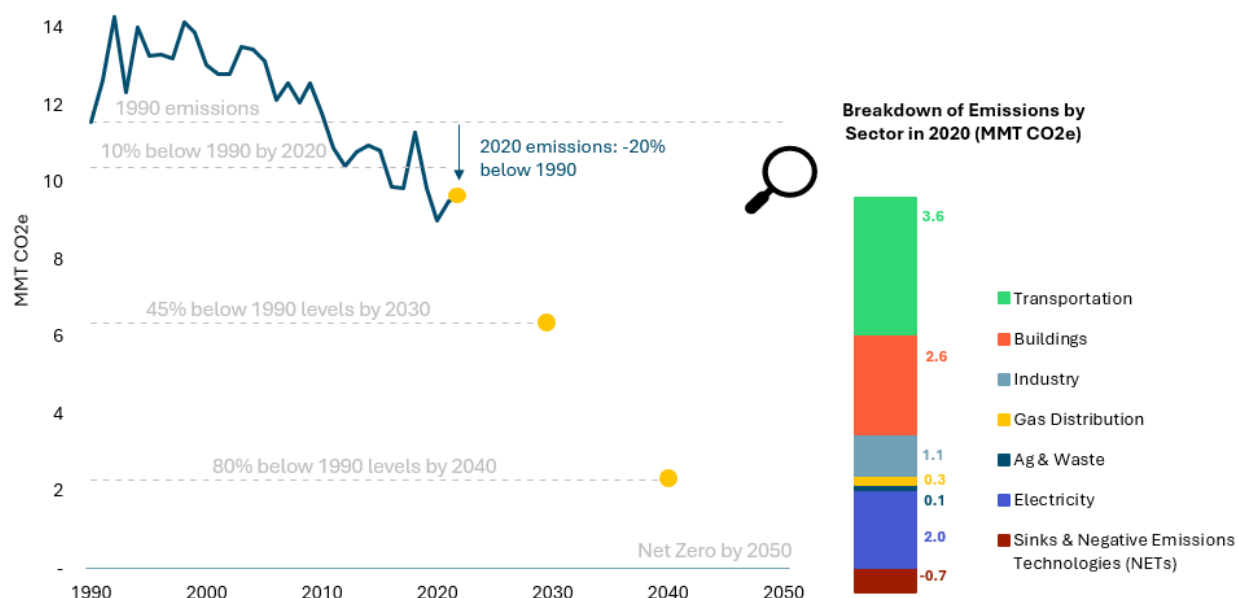
³⁴ *Ibid.*, at p. 5, 27, & 29

³⁵ EIA, 2020 Residential Energy Consumption Survey (RECS)

³⁶ State of Rhode Island Office of Energy Resources, "Oil (Heating Only)".

from 1990 levels, thus achieving the Act on Climate’s 2020 emission reduction mandate to reduce 10% below 1990 levels (Figure 11).³⁷ Overall, the transportation sector was the highest emitting sector, with nearly 40% of total emissions stemming from both on- and off-road sources in 2020. Electricity consumption was the second largest source of emissions in 2020, making up about 21% of total emissions and representing fossil fuel-generated power in the region. Combustion of fossil fuels in buildings comprised about 27% of total emissions in Rhode Island in 2020, primarily from natural gas and oil furnaces and boilers. The remaining emissions in Rhode Island stemmed from the industrial sector, gas distribution, agriculture, and waste.³⁸

Figure 11. Historical and 2020 Emissions Breakdown in Rhode Island³⁹



Rhode Island’s GHG Accounting Framework

The Rhode Island 2020 GHG Inventory primarily relies upon the Environmental Protection Agency (EPA)’s emissions accounting framework reported in the State Inventory Tool (SIT). The accounting framework assumes a 100-year Global Warming Potential (GWP) based on the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5).⁴⁰ The GWP is a metric of how much a given gas, such as methane (CH₄) or nitrous oxide (N₂O), will contribute to global warming compared to carbon dioxide (CO₂) over a certain time period. By definition, CO₂ has a GWP of 1 so that it can be used as the reference gas.⁴¹ GWPs enable the comparison between different gases by

³⁷ Source: <https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf>

³⁸ Ibid.

³⁹ The categories in this chart are those used by E3 in the Technical Analysis modeling. The categories may vary slightly from those used in the RI GHG Inventory.

⁴⁰ IPCC AR5: <https://www.ipcc.ch/assessment-report/ar5/>

⁴¹ Source: <https://www.epa.gov/ghgemissions/understanding-global-warming-potentials>

putting all climate pollution effects into a single metric – in this case based on a 100-year time horizon. AR5 GWPs used by the RI 2020 GHG Inventory are shown in Table 4 below.

Table 4. IPCC AR5 GWPs

Pollutant	AR5 Global Warming Potential (GWP)
CO ₂	1
CH ₄	28
N ₂ O	265

Other key factors in Rhode Island’s current emissions accounting methodology include:

- + **Consumption-based electricity accounting.** The electric sector uses a consumption-based emissions accounting method. A consumption-based framework accounts for all emissions associated with electricity used within the state, rather than generated within the state.⁴²
- + **Net Zero GHG accounting.** The current netting methodology in Rhode Island involves summarizing all GHG sources and then subtracting all GHG sinks, rather than netting for individual GHGs.⁴³
- + **Renewable fuels.** Renewable fuels are considered carbon neutral in Rhode Island’s current GHG emissions accounting methodology, and current emissions from biodiesel usage in the state are not reported.⁴⁴ More details on emissions associated with renewable fuels can be found in the textbox below.

In the Technical Analysis, the treatment of renewable fuels follows the Rhode Island accounting framework, which means that the use of renewable fuels is assumed to lead to gross GHG emissions reductions, effectively assuming all greenhouse gas emissions from renewable fuels have an emissions factor of zero. Through sensitivity analysis, E3 explores the impact of Rhode Island adopting alternative accounting frameworks that would treat the emissions factor from renewable fuels as non-zero, accounting for upstream and lifecycle emission associated with the combustion of fuels in the state, as detailed further in Chapter 3.

⁴² <https://dem.ri.gov/sites/g/files/xkgbur861/files/programs/air/documents/ghg-memo.pdf>

⁴³ Net Zero GHG accounting was confirmed by RI Department of Environmental Management (RIDEM) on the Stakeholder Committee.

⁴⁴ Rhode Island 202 GHG Emissions Inventory. <https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf>

Emissions associated with renewable fuels

Rhode Island considers emissions associated with renewable fuels as carbon neutral, which is in line with the treatment of emissions from biogenic sources used by the Environmental Protection Agency (EPA) and guidance from the Intergovernmental Panel on Climate Change (IPCC).⁴⁵ Some biogenic emissions in Rhode Island's inventory are reported for informational purposes, but those emissions are not counted towards the sum of gross emissions in the state. Although the combustion of biomass and biofuels in Rhode Island result in GHG emissions in the state, it is assumed that biogenic sources absorb a similar amount of CO₂ *from the atmosphere* over their lifetime to what they release *into the atmosphere* at the point of combustion. Since EPA's national inventory includes an estimation of carbon sequestration resulting from biogenic sources, biogenic CO₂ emissions are indirectly captured within the land-use, land-use change and forestry sector of the national inventory, even though these emissions might ultimately take place in different sectors or across different state borders.⁴⁶

Many stakeholders in and outside of Rhode Island have cautioned the current treatment of biogenic emissions as carbon neutral, stating the complexity and uncertainty associated with lifecycle emissions. EPA acknowledges this complexity and notes that *"technical, policy and legal contexts may change over time that could lead to revisiting the treatment of biogenic emissions as necessary."*⁴⁷ In addition, the Rhode Island Department of Environmental Management (RIDEM) in its latest inventory recognizes the ongoing international controversy surrounding GHG accounting for energy generated from biogenic sources and continues to collaborate with stakeholders on a more robust framework.⁴⁸

⁴⁵ See: https://www.epa.gov/sites/default/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf; IPCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 1, Chapter 8

⁴⁶ https://www.epa.gov/sites/default/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf

⁴⁷ Ibid.

⁴⁸ 2020 Rhode Island GHG Emissions Inventory. Available at: <https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf>

3. Technical Analysis Approach

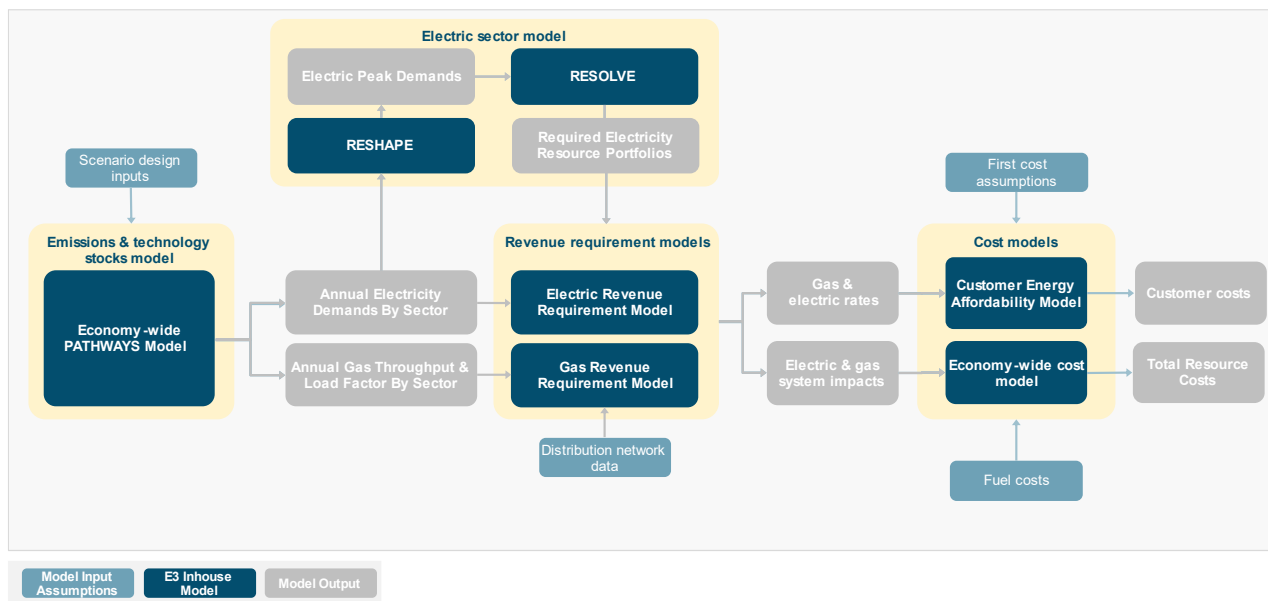
Modeling Framework

The Technical Analysis was developed using E3's in-house modeling framework designed to evaluate the impact of decarbonization targets on the state of Rhode Island, Rhode Island's gas distribution system and Rhode Island residents. The framework combines a variety of models that together assess the impact of distinct decarbonization pathways that achieve the Act on Climate on emissions, technology adoption, fuels, electric system impacts and gas system impacts, as well as evaluation criteria such as costs and affordability. The modeling framework consists of 4 model categories:

- + **Rhode Island emissions and technology stock model:** E3 used the economy-wide PATHWAYS model to assess emissions and energy use over time. This model considers emissions and energy use across all sectors in Rhode Island and determines the impact of changes in technology stock on energy use and emissions.
- + **Electric sector model:** E3 used a combination of RESHAPE and RESOLVE to assess impacts of scenarios on the electric sector. RESHAPE assesses the impacts of building electrification on annual and hourly electric loads, incorporating 40 years of historical weather data. RESOLVE is E3's electric sector capacity expansion model that assesses optimized electric sector portfolios in the ISO-NE area to maintain electric sector reliability.
- + **Revenue requirement models:** E3 used an in-house, long-term (through 2050) revenue requirement framework that assesses the relationships between changing gas supply costs, throughput, capital investment, cost allocation and more on utility revenue requirements and rates. A less detailed, top-down revenue requirement model was used to assess in-state electric sector impacts and rates.
- + **Cost models:** E3 uses a Customer Energy Affordability Model to calculate equipment retrofit costs and monthly energy and gas bills over time, using the rates calculated in the Revenue Requirement models. The Economy-wide cost model is used to assess the impact of pathways on total incremental resource costs for the state of Rhode Island.

A visualization of these categories that outlines the relationship between the models is provided in Figure 12. A detailed description of the models and assumptions is provided in Appendix A.

Figure 12. E3's Modeling Framework



Scenario Development

The scenarios described in this report represent distinct, plausible futures for how Rhode Island could meet its climate targets over the next several decades. Each scenario is designed to evaluate a unique combination of decarbonization strategies in order to meet Rhode Island’s GHG reduction targets. The scenarios were developed in conjunction with the Stakeholder Committee and Technical Working Group with final direction and approval from the PUC, with the goal of answering key research questions related to the actions Rhode Island can take to achieve decarbonization across the whole economy, emphasizing, in particular, the role of natural gas distribution and the heating sector.

The decarbonization scenarios modeled for the Technical Analysis are not forecasts; instead, the pathways are modeled through a “backcasting” approach. Backcasting in this context means that E3 designed a key end-state outcome – statewide and sector-specific emissions reductions by 2030, 2040 and 2050 – and assessed the necessary changes in stock and fuel use over time in order to achieve that end-state outcome. While the scenarios are then compared against each other across multiple evaluation criteria, the intention is not to pick a preferred solution amongst scenarios. Instead, scenario analysis allows for the identification of commonalities, differences, and key implications for near- and long-term planning that can be incorporated into policy and regulatory design.

In addition, it is important to note that the decarbonization scenarios developed are not optimizations; instead, each scenario is meant to answer “what if” questions about the future of Rhode Island’s energy system, rather than determine the optimal – or least-cost – path to decarbonization. Aside from the electric sector modeling framework that does optimize for least-cost electricity portfolios, the scenarios do not optimize for the most cost-effective solutions.

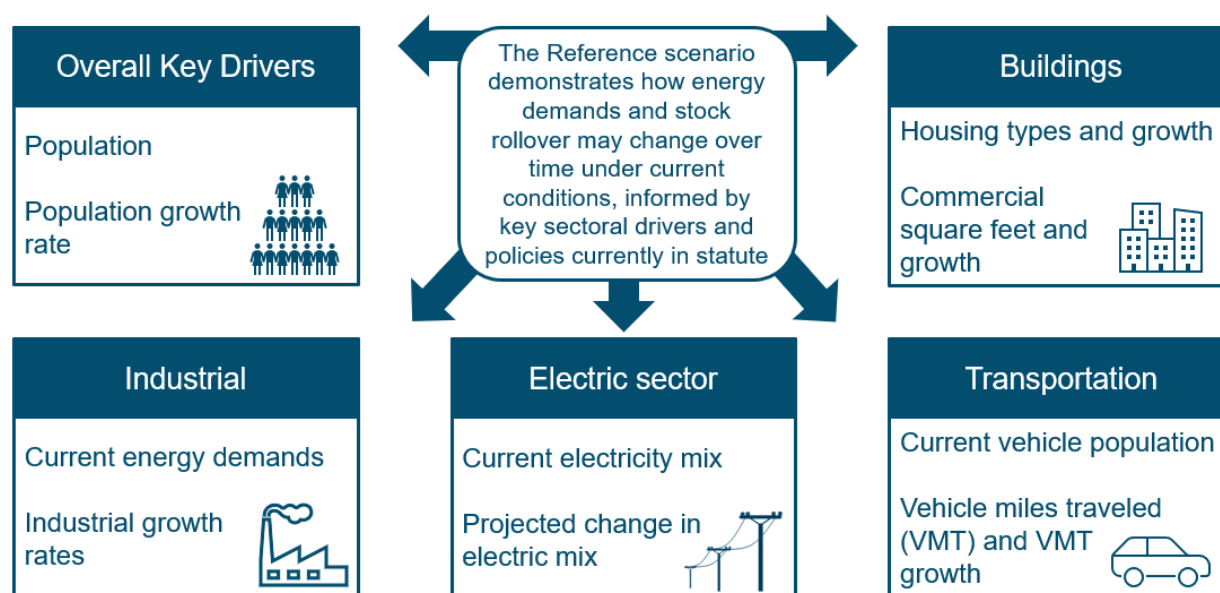
Scenarios are developed using a bottom-up accounting method, built upon detailed assumptions around building and heating characteristics, customer demographics, energy efficiency programs, emissions accounting framework, and the current regulatory landscape.

Input assumptions, especially key assumptions that have a driving impact on the outcome of the analysis, were discussed in detail with the TWG and iterated on through discussions and feedback. Throughout the TWG process, E3 shared an Excel-spreadsheet with draft input assumptions for TWG review and incorporated TWG feedback through multiple iterations of the document. The final overview of input assumptions used in the Technical Analysis is provided as a separate appendix to this report (Appendix B).

Reference Scenario

In order to understand the impact of existing policies on state energy demands, GHG emissions, and progress toward decarbonization goals, E3 first constructed a reference scenario, which captures the dynamics of all existing conditions and policies that are currently on-the-books in Rhode Island with the exception of the Act on Climate. The goal of this scenario is to estimate the path the state is on with respect to energy and GHG emissions before layering on additional actions needed to meet the GHG targets laid out in the Act. Specifically, the reference scenario is intended to identify the magnitude and scope of additional mitigation needs, after considering the impact of existing policies on emissions and energy demands. The energy consumption and emissions in the reference scenario are informed by key sectoral drivers in Rhode Island, such as population, housing units, and vehicle population (see Figure 13).

Figure 13. Reference Scenario Key Sectoral Drivers



Detailed assumptions and data sources for key drivers are included in Appendix A.1. In addition to these key drivers, the reference scenario includes any policies that are currently in statute in Rhode Island, such as:

- + **Rhode Island Biodiesel Heating Oil Act of 2013/2021:** All building (residential and commercial) oil customers receive heating oil with a 10% biodiesel blend in July 2023, increasing to 50% by 2030.⁴⁹
- + **Federal Energy Conservation Standards for Consumer Furnaces:** All new gas furnace sales must be 95% fuel efficient by 2029.⁵⁰
- + **Rhode Island's Renewable Energy Standard (RES):** Rhode Island's electric grid will be powered by 100% renewable energy by 2033, including interim targets (36% electricity from renewable sources by 2025, 74% electricity from renewable sources by 2030, among others). The RES is not a production target; it requires utility companies to procure clean energy projects, purchase renewable energy certificates (RECs), or pay an alternative compliance payment that is typically above the market price of RECs.⁵¹

The reference scenario also includes assumptions around the role of efficiency and the pace of decarbonization in the buildings and transportation sectors under existing conditions.

- + **Building envelopes and weatherization.** Based on data provided by NV5, it is anticipated that in the reference scenario nearly 60% of residential buildings and about 10% of commercial buildings will undergo light-touch weatherization retrofits by 2050.⁵² Light-touch retrofits include basic weatherization upgrades, such as glazing and partial air sealing, and are expected to reduce heating energy service demand by approximately 15%.⁵³
- + **Building electrification.** A modest level of heat pump growth (25% residential space heating stocks and 15% of commercial are heat pumps by 2050) was included in the reference scenario, primarily driven by electric resistance conversions and existing federal/state heat pump incentives (e.g. Inflation Reduction Act, Clean Heat RI, Rhode Island Energy Rebates).^{54,55,56}
- + **Transportation electrification.** Advanced Clean Cars II (ACCI) and Advanced Clean Trucks (ACT) policies were not incorporated into the reference scenario based on discussions with the Stakeholder Committee and Technical Working Group, in order to allow for a better comparison of the isolated impacts of the regulation compared to impacts occurring from natural demand drivers. The reference scenario assumes that electric vehicle penetration

⁴⁹ <http://webserver.rilin.state.ri.us/BillText/BillText21/HouseText21/H5132A.pdf>;
<http://webserver.rilin.state.ri.us/BillText/BillText21/SenateText21/S0357A.pdf>

⁵⁰ <https://www.regulations.gov/document/EERE-2014-BT-STD-0031-4107>

⁵¹ <http://webserver.rilin.state.ri.us/BillText/BillText22/HouseText22/H7277A.pdf>;
<http://webserver.rilin.state.ri.us/BillText/BillText22/SenateText22/S2274Aaa.pdf>

⁵² NV5 is an engineering consulting firm with deep energy efficiency expertise. The firm was a representative in the Technical Working Group on behalf of RI Energy Efficiency & Resource Management and provided data and forecasts on building envelope adoption in Rhode Island.

⁵³ Detailed assumptions can be found in Appendix A.1.

⁵⁴ <https://www.whitehouse.gov/cleanenergy/>

⁵⁵ <https://cleanheatri.com/>

⁵⁶ https://www.rienergy.com/media/ri-energy/pdfs/energy-efficiency/ri_electric_heating-cooling_form.pdf

would reach 10% by 2030, as targeted by Rhode Island’s Executive Climate Change Coordinating Council (EC4) in the 2022 Climate Update⁵⁷, with anticipated penetration primarily driven by current rebate programs, such as DRIVE EV.⁵⁸

Decarbonization Scenarios

In addition to a reference scenario, E3 designed six decarbonization scenarios, each presenting a distinct pathway to achieving climate targets in Rhode Island. All scenarios comply with Rhode Island’s Act on Climate, which requires a net emissions reduction target of 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and net zero by 2050.⁵⁹ Each scenario was designed to answer unique research questions on the role of different strategies to mitigate GHG emissions and the future of natural gas in Rhode Island:

- + **High Electrification:** What is the impact of pursuing a full electrification decarbonization pathway that transitions Rhode Island away from gas infrastructure?
- + **Hybrid with Delivered Fuels Backup:** What is the impact of hybrid electrification with delivered fuels (i.e., the use of an electric heat pump with a delivered fuel-powered furnace or boiler to be used during the coldest conditions)? What is the net benefit of avoiding gas infrastructure/decommissioning?
- + **Hybrid with Gas Backup:** What is the impact of hybrid electrification with gas (i.e., the use of an electric heat pump with a gas-powered furnace or boiler to be used during the coldest conditions)? How can Rhode Island leverage existing gas infrastructure to reduce electric sector build out?
- + **Staged Electrification:** How can Rhode Island leverage existing infrastructure and mitigate customer impacts in the near-term, while allowing for a managed transition and achieving long-term electrification?
- + **Alternative Heat Infrastructure:** How can highly efficient heating systems (e.g., networked geothermal) support decarbonization in Rhode Island? What is their net impact? Can they provide an alternative to gas investments?
- + **Continued Use of Gas:** How can existing gas infrastructure support decarbonization? What is the effect of and potential limit to remaining fossil gas and renewable fuels such as biomethane, hydrogen and other emissions-compliant fuels??

⁵⁷ <https://climatechange.ri.gov/media/1261/download?language=en>.

⁵⁸ DRIVE EV is an electric vehicle rebate project that provides incentives to Rhode Island residents and businesses to adopt electric vehicles. <https://drive.ri.gov/>.

⁵⁹ Gross emissions represent the total amount of greenhouse gases that enter the atmosphere; net emissions reductions account for the balancing or offsetting of emissions that occurs through negative emissions technologies (NETs) and the Land Use, Land Use Change, and Forestry (LULUCF) sector.

Delivered Fuels as Backup

The use of delivered fuels as a hybrid heat pump backup fuel option to mitigate electric system peak impacts in winter is a relatively new concept suggested by the Stakeholder Committee that has not yet been studied in detail elsewhere in the United States. Following this concept, customers currently using delivered fuels as their main source of heating or customers that currently use gas as a main source of heating would adopt all-electric heat pumps, while installing or keeping a furnace or boiler that uses fuel oil, propane or another form of delivered fuel that does not rely on networked infrastructure. A potential advantage of the concept for existing gas customers is that networked infrastructure, such as gas pipelines, can be decommissioned with less impact on customers or the electric grid. Uncertainty exists around the extent to which required tank storage is feasible on customer premises and around the impact of the above-ground delivery of fuels, such as truck movements. These uncertainties are not investigated in the Technical Analysis and require further study.

Throughout this report, E3 uses the term delivered fuels as an umbrella term covering all non-regulated fuels such as propane and fuel oil. In our modeling framework, a fuel oil furnace or boiler was used as a proxy to define the impacts of the concept for all types of delivered fuel conversions. However, the conversion to propane may result in advantages over fuel oil given the emissions impact of propane over fuel oil. In addition, converting to the use of a propane boiler or furnace may be possible with limited adaptations required to an existing gas furnace or boiler. For example, in a “staged” transition, customers with an existing gas furnace or boiler could make burner-tip adjustments to their appliances by switching from gas to propane fuel while installing a partial load electric heat pump. These customers could then transition to whole-home electric heating later in time, at the end-of-life of their furnace or boiler. This conversion could avoid the upfront cost of installing a new boiler or furnace for backup use, although it is important to note that this concept primarily applies to scenarios that see a longer-term transition to whole-home electric heating, such as the Staged Electrification scenario. E3 explores the impact of avoided backup system costs as a sensitivity in the Technical Analysis.

In each of these scenarios, the role and use of the gas system is expected to change through fuel switching, efficiency or timing of technology adoption. Some pathways, such as Hybrid with Gas Backup and Continued Use of Gas keep a role for the gas system while others, such as High Electrification and Hybrid with Delivered Fuels Backup – move away from using the gas system over time. In these scenarios, the gas system is eventually expected to decommission where feasible.

Key scenario parameters

Given this study's emphasis on the role of the natural gas system in statewide decarbonization objectives, the Technical Analysis primarily focuses on mitigation strategies within the heating sector. As a result, the scenarios vary in levels of electrification and reliance on renewable fuels while keeping other factors mostly constant across scenarios to allow for comprehensive comparisons. However, each sector plays an important role in Rhode Island's path to net zero, even if many parameters are aligned across scenarios. The high-level scenario parameters are shown in the figure below.

Figure 14. Overview of Scenario Parameters

	Efficiency & Weatherization	Building/Industry Electrification	Zero Emission Vehicles	Clean Electricity	Low-Carbon Fuel	Ag., Waste, & Natural Sinks	Negative Emission Technologies
High Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Hybrid Electrification + Delivered Fuels Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Hybrid Electrification + Gas Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Staged Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Alternative Heat Infrastructure	Very High	High	Very High	Very High	Medium	Medium	Low
Continued Use of Gas	Very High	Medium	Very High	Very High	High	Medium	Low

Note: there may be minor variation across scenarios to account for rounding/balancing of final GHG targets.

- + Efficiency and Weatherization.** Efficiency and weatherization assumptions are kept constant across all scenarios. It is assumed that about 60% of residential buildings and nearly 10% of commercial buildings will undergo light-touch weatherization retrofits by 2050. All decarbonization scenarios additionally assume a nearly 35% adoption of deep-shell retrofits by 2050 in the Residential sector. Other types of efficiency are also assumed to improve over time in Rhode Island, such as technology performance, behavioral conservation, and industrial efficiency. Details on all efficiency parameters and results can be found in Chapter 4 and Appendix A.1.
- + Building/Industry Electrification.** Given the Technical Analysis' focus on the heating sector, levels of building and industrial electrification vary significantly across scenarios. Depending on the design of each scenario, different levels of electrification and industry are deployed.

Scenarios that explore the impact of high electrification and gas decommissioning include high levels of heat pump adoption in buildings and the industrial sector electrifies as much as technically feasible. For scenarios that are meant to show the impact of continued reliance on the natural gas system, fewer heat pumps are adopted in buildings and industry relies more heavily on low-carbon fuels instead of electrification. Additionally, a larger share of the heat pumps adopted in those scenarios are systems with gas backup.

- + **Zero Emission Vehicles.** Zero-emission vehicle (ZEV) adoption levels are held constant across all scenarios. The light-duty vehicle (LDV) and medium- and heavy-duty vehicle (MHDV) electrification trajectories are largely driven by the adoption of ACCII and ACT in Rhode Island.
- + **Clean Electricity.** Electric sector assumptions are held constant across all scenarios, although the variations in building electrification will lead to different levels of load growth. Like the reference scenario, all decarbonization scenarios comply with Rhode Island's RES. The decarbonization scenarios also account for electric sector targets outside of the RES, including the ambition to add 600-1000 additional MW of offshore wind to the state's clean energy portfolio.⁶⁰
- + **Renewable Fuels.** Given the Technical Analysis' focus on the role of the natural gas system, levels of renewable fuels vary across scenarios. Scenarios that rely on higher levels of electrification and gas system decommissioning require lower blends of renewable fuels into the remaining fuel mix by 2050 to reach emissions targets. Scenarios that maintain a larger use of the natural gas system by 2050 require higher levels of renewable fuel blends in order to reach emissions targets. As described in the textbox below, E3 uses the term renewable fuels as an umbrella term considering all types of emissions-compliant fuels.
- + **Ag., Waste, & Natural Sinks.** Parameters around agriculture, solid waste, wastewater, and natural carbon sinks are held constant across scenarios. Overall, these sectors make up a very small component of Rhode Island's economywide emissions. Like the reference scenario, it is assumed that agricultural emissions will remain flat over time, as reflected in historical trends from the Rhode Island GHG Inventory and due to the difficulty to decarbonize. Also aligned with the reference scenario, solid waste emissions are assumed to phase out to zero emissions by 2040 after the Central Landfill is closed in 2048, consistent with the 2016 Rhode Island GHG Reduction Plan.⁶¹ Unlike in the reference scenario, it is assumed that carbon sequestration will remain mostly flat through 2050 due to no net forest, wetland, or cropland loss (in line with the 2016 Rhode Island GHG Reduction Plan).⁶² No net losses in forestland assumes the adoption of conservation measures and that new developments will be built denser and on already-developed lands.

⁶⁰ In 2022, Governor Dan McKee signed a bill that required a request for proposals for up to 600-1,000 MW of offshore wind capacity. Although the initial bid responses were rejected, additional RFPs have been announced. See: S 2583. State of Rhode Island. General Assembly 2022.

<http://webserver.rilin.state.ri.us/BillText/BillText22/SenateText22/S2583.pdf>; Rhode Island Energy's Long-Term Clean Energy Procurement 2023 OSW RFP: <https://ricleanenergyrfp.com/2023-osw-rfp/>

⁶¹ <https://climatechange.ri.gov/sites/g/files/xkgbur481/files/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf>

⁶² Ibid.

- + **Negative Emissions Technologies (NETs).** The use of NETs to meet emissions targets is held constant across all scenarios.⁶³ NETs are used as a final measure to align emissions across all sectors with the net zero target by 2050.

Renewable fuel emissions compliance

E3 modeled a role for renewable fuels in transportation, buildings, and industry, detailed further in Chapter 4. It is likely that Rhode Island will need to become a net importer of renewable fuels to decarbonize end uses that are challenging to electrify as described in more detail in Chapter 5. The availability, efficacy and costs associated with these fuels is uncertain. E3 captured some of this uncertainty through sensitivity analysis, but additional detail on the role and implications of using renewable fuels in the state warrants further policy discussion.

Some members of the Technical Working Group have suggested that other forms of emissions compliance mechanisms could fulfill the same role as renewable fuels. An example would be offsetting fossil fuel combustion through negative emissions technologies such as direct air capture (note that this is not reflected in the modeling). The latest National Climate Assessment states that further research is required to better understand whether producing and burning physical low-carbon fuels is lower in costs and more sustainable than managing emissions from fossil fuels through carbon dioxide removal from the atmosphere.⁶⁴ In Rhode Island’s current accounting framework, such a method would contribute to the net emissions target as long as the carbon dioxide removal takes place within state borders. More discussion and clarity is required to understand the scope and eligibility of these options and their relation to the state’s accounting framework.

Acknowledging the uncertainty associated with the availability, costs and efficiency of renewable fuels, E3 uses the term “renewable fuels as” an umbrella term encompassing emissions-compliant fuels without specifically prescribing their source. A similar approach is taken for the calculation of costs associated with renewable fuels (described in Appendix A) that uses a simplified “marginal cost of abatement” compliance approach with low and high bounds without detailing the cost of production of different type of fuels. Additional considerations and implications of the reliance on out-of-state fuels are described in Chapter 5.

⁶³ There may be minor variation across scenarios to account for rounding and balancing of final GHG targets.

⁶⁴ Davis, S.J., R.S. Dodder, D.D. Turner, I.M.L. Azevedo, M. Bazilian, J. Bistline, S. Carley, C.T.M. Clack, J.E. Fargione, E. Grubert, J. Hill, A.L. Hollis, A. Jenn, R.A. Jones, E. Masanet, E.N. Mayfield, M. Muratori, W. Peng, and B.C. Sellers, 2023: Ch. 32. Mitigation. In: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. <https://doi.org/10.7930/NCA5.2023.CH32>

Detailed scenario parameters for space heating purposes

Each scenario primarily focuses on how the deployment of different types of space heating technologies (see Table 5) and the use of renewable fuels⁶⁵ in buildings and industry might shape Rhode Island's future energy landscape.

Table 5. Key Narrative and Space Heating (Residential and Commercial) Technology Assumptions for Each Scenario

Scenario Name	Key Scenario Narrative (focused on heating sector transformations)	Key ⁶⁶ Space Heating Technologies					
		ASHP/Electric Boilers ^{67,68}	GSHP ⁶⁹	Hybrid HP/Boilers w/DF ⁷⁰	Hybrid HP/Boilers w/Gas	Networked Geo.	Eff. Gas Furnace
High Electrification	The High Electrification scenario focuses on high levels of efficiency and deployment of primarily all-electric heating in buildings. A small number of buildings keep a backup heating source. The industrial sector electrifies as much as technically feasible.	●	●				
Hybrid Electrification with Delivered Fuels (DF) Backup	The Hybrid with Delivered Fuels Backup scenario focuses on high levels of efficiency and deployment of primarily hybrid heat pumps with delivered fuels as backup in buildings. A modest number of buildings convert to all-electric heating. The industrial sector electrifies as much as technically feasible.			●			
Hybrid Electrification with Gas Backup	The Hybrid with Gas Backup scenario focuses on high levels of efficiency and deployment of primarily hybrid heat pumps with gas as backup in buildings. A small number of buildings convert to all-electric heating. The industrial sector converts to a mix of electrification and renewable fuels (e.g., hydrogen).				●		

⁶⁵ See textbox above.

⁶⁶ Note this table does not show all space heating technologies deployed in each scenario. The table is simply meant to highlight the technologies of primary focus in each pathway.

⁶⁷ ASHP: Air Source Heat Pump

⁶⁸ In the Commercial sector, buildings undergoing electrification convert to either an electric boiler or an ASHP, depending on the existing technology type (boiler vs. furnace). Further details can be found in Chapter 4.

⁶⁹ GSHP: Ground Source Heat Pump

⁷⁰ HP: Heat Pump; DF: Delivered Fuels

Staged Electrification	The Staged Electrification scenario focuses on a staged transition for buildings starting with a ramp up of hybrid heat pumps in the near-term (both gas and delivered fuels). By the mid-2030s, buildings and industry begin to convert to all-electric where possible.	●	●	●	●		
Alternative Heat Infrastructure	The Alternative Heat Infrastructure scenario focuses on a mix of networked geothermal systems, all-electric heating, and hybrid HPs in buildings. The industrial sector converts to a mix of electrification and renewable fuels (e.g., hydrogen).	●			●	●	
Continued Use of Gas	The Continued Use of Gas scenario focuses on a mix of high-efficiency gas appliances and hybrid heat pumps in buildings. The industrial sector converts to a mix of electrification and dependence on renewable fuels (e.g., hydrogen). The gas system continues to serve customers all year.				●		●

Sensitivity Analysis

The scenario approach used by E3 is assumptions-driven and, as any outlook towards 2050, is inherently uncertain across factors related to costs, consumer behavior, technology development and other factors. To account for key uncertainties, E3 incorporated sensitivity analyses in its modeling framework across a number of key parameters that are likely to have a meaningful impact on the results of the analysis. In particular, E3 incorporated two types of sensitivities:

1. Sensitivities impacting **the level and pace of emissions reductions**, such as technology adoption parameters, efficiency assumptions and assumptions regarding the accounting of GHG emissions;
2. Sensitivities impacting **the costs of the transition**.

The table below provides an overview of the sensitivities included in this analysis. A detailed overview of assumptions related to sensitivity analyses is provided in Appendix A.1.

Table 6. Overview of Sensitivity Parameters

Sensitivity analysis	Scope	Expected insights
Sensitivities impacting the level and pace of emissions reductions		
Higher levels of cold climate heat pumps efficiency performance	<ul style="list-style-type: none"> Modeled as a sensitivity on building sector energy demands and electric capacity needs. Modeled for the High Electrification scenario only. 	Potential electric sector impacts resulting from the adoption of higher efficiency technology.
Lower levels of transportation electrification , e.g.,	<ul style="list-style-type: none"> Modeled as a sensitivity onto transportation sector technology adoption levels 	Potential impacts to the heating sector resulting

slower pace of adoption than required by ACCII.	<ul style="list-style-type: none"> Modeled for the High Electrification scenario only. 	from the slower adoption of electric vehicles.
Different GHG accounting frameworks , including higher GWPs, upstream fuel emissions and zero emissions benefit from biofuels	<ul style="list-style-type: none"> Modeled as a sensitivity onto fuel emissions factors through 3 options: <ul style="list-style-type: none"> Lifecycle emissions associated with fuels 20-year GWP No emissions benefits from renewable fuels Modeled for all scenarios 	Potential risks associated with higher reliance on biofuels
Sensitivities impacting the costs of the transition.		
Elements of a managed transition, i.e. targeted electrification and gas decommissioning on gas system investments, rates, and resource cost.	<ul style="list-style-type: none"> Modeled as a sensitivity onto gas sector costs (avoidance of leak-prone pipe replacement) Modeled for all scenarios 	Potential level of cost savings on the gas system that can be achieved per scenario if electrification takes place through a managed approach.
Cost of cold-climate air source, ground-source and hybrid heat pumps	<ul style="list-style-type: none"> Modeled as low/high bounds on heat pump capital and installation costs 	Potential impact of varying cost input assumptions on total resource costs and the comparison of cost risks across scenarios.
Cost of networked geothermal systems	<ul style="list-style-type: none"> Modeled as low/high bounds on networked geothermal installation capital costs (excluding behind-the-meter costs) 	
Cost of renewable fuels	<ul style="list-style-type: none"> Modeled as low/high bounds on the compliance cost of fuel for renewable natural gas, diesel, and gasoline 	
Cost of Renewable Energy Certificates (RECs)	<ul style="list-style-type: none"> Modeled as low/high bounds on the cost of purchasing RECs to comply with the 100% RES standard 	
Cost of avoiding hybrid electrification backup use	<ul style="list-style-type: none"> Modeled as an additional sensitivity onto the cost of Air Source Heat Pumps (ASHPs) with backup use (<u>not included in low/high bounds</u>) Modeled for scenarios that use ASHP with backup use 	Potential impact of a “staged” approach to backup use where customers keep existing furnaces or boilers as backup

Overview of Evaluation Criteria and Metrics

To assess the implications and feasibility of the modeled decarbonization scenarios, E3 together with the Stakeholder Committee defined a set of key evaluation criteria. Evaluation criteria can be used as an objective measure to assess benefits, risks and challenges associated with pathways, without choosing a preferred set of pathways or weighing one criterion more heavily over another. In particular, the evaluation criteria in this analysis are used to distill commonalities and shared opportunities and risks that can be taken into account by policymakers in the policy development phase of this docket.

E3 assessed pathways across a combination of both quantitative and qualitative factors. An overview of evaluation criteria and associated metrics is provided in the table below.

Table 7. Overview of Evaluation Criteria and Metrics used to Assess Implications of Decarbonization Pathways

Criteria	Definition	Based on metric
Quantitatively assessed		
Scenario Costs	Statewide total cost (cost of fuels, capital costs, electric/gas system costs, etc.) associated with AoC compliance and associated cost of abatement	<ul style="list-style-type: none"> Cumulative incremental Net Present Value (NPV) and annual total resource costs of pathways compared to reference scenario \$/tonne CO₂e abated by subsector
Customer affordability	Total cost of ownership for individual customers adopting decarbonization measures	<ul style="list-style-type: none"> Monthly total bills for customers adopting heating technologies (“migrating customers”)
	The effect of customer migrations on the remaining costs for customers on the gas system	<ul style="list-style-type: none"> Monthly total bills for customers <u>not</u> adopting decarbonized heating technologies (“non-migrating customers”)
Qualitatively assessed		
Customer choice	The extent to which customers are able to choose their preferred heating solution	<ul style="list-style-type: none"> Estimated number of targeted electrification projects in 2035
Workforce impacts	The extent to which scenarios impact the need for a difference workforce in the state	<ul style="list-style-type: none"> Not based on quantitative metrics (described qualitatively only)
Reliance on Regional Fuel Supply	Reliance on level of renewable fuel that, given Rhode Island’s footprint, will likely need to be imported from out of state	<ul style="list-style-type: none"> Annual volume of renewable fuels
Technology Readiness	The extent to which a pathway relies on commercially available technologies	<ul style="list-style-type: none"> “Technology readiness level” (TRL) range that will be required in each scenario to comply with AoC.
Pace of electric system expansion	The pace and scale of electric sector infrastructure needs	<ul style="list-style-type: none"> Near-term (up to 2035) transmission and distribution (T&D) investments and new installation of electric generation resources (e.g. offshore wind).

Notably, each scenario is modeled to reflect a safe and reliable energy system in Rhode Island per existing gas and electric standards, while achieving similar levels of greenhouse gas reductions. As such, safety and reliability are not evaluated as criteria that differ between scenarios.

4. Decarbonization Pathways – Technical Results

This chapter details the results of Technical Analysis, describing each decarbonization scenario's impact on emissions, technology adoption, energy demand, the gas system, and the electric grid. Additional implications across evaluation criteria for each pathway will be discussed in Chapter 5.

Impact on Emissions

A primary component of reaching the targets set out in Rhode Island's Act on Climate is the mitigation of GHG emissions across Rhode Island's economy. As such, a key focus of this study is determining what decarbonization measures will need to be taken in all sectors of the economy in order to achieve Rhode Island's climate goals and what level of emissions reductions these measures can achieve.

Reference Scenario Emissions

While Rhode Island's 2020 emissions showed a 20% reduction in emissions compared to a 1990 baseline, 2020 was not a standard year due to the COVID-19 pandemic. COVID-19 caused a dip in normal activities, such as driving to work, leading to abnormally low energy demand. With the economy's rebound from the pandemic and return to normal activities, energy usage data available from EIA for 2021 and 2022 implies that Rhode Island can expect emissions to increase again in the next two years (Figure 15), with 2022 emissions landing about 15% below 1990 levels. After 2022, current economywide conditions and existing policies are expected to lead to ongoing emissions reductions in the reference scenario.

Overall, the reference scenario achieves a 40% emissions reduction by 2030 (% relative to 1990), a 55% reduction by 2040, and 57% emissions reduction by 2050, as shown in Figure 15. Emissions reductions are driven by a combination of measures across the economy:

- + **Transportation.** The transportation sector in the reference scenario achieves a 28% sectoral emissions reduction by 2030, 43% emissions reduction by 2040, and 45% reduction by 2050 compared to 1990 levels. Reductions are driven by an increase in EV penetration consistent with historical levels and targets set by EC4, reaching approximately 10% of LDV stocks by 2030 and 37% of LDV stocks by 2050. Zero-emission MHDVs grow modestly over the next three decades. There is overall growth in Vehicle Miles Traveled (VMT) per vehicle, but a decline in total number of vehicles due to population decreases across the state. The reference scenario does not include impacts of adoption of ACCII/ACT.
- + **Buildings.** The buildings sector achieves a sectoral emissions reduction of 35% by 2030, 41% by 2040, and 45 by 2050, compared to 1990 levels. The reductions are driven by modest heat pump adoption, with about 5% of customers adopting heat pumps by 2030 and about 10-15% of customers adopting heat pumps by 2050. It is also anticipated that a portion of delivered fuel customers will convert to gas heating at a pace aligned with historical levels in the reference scenario. Customers that remain on fuel oil will have a 50% biodiesel blend in

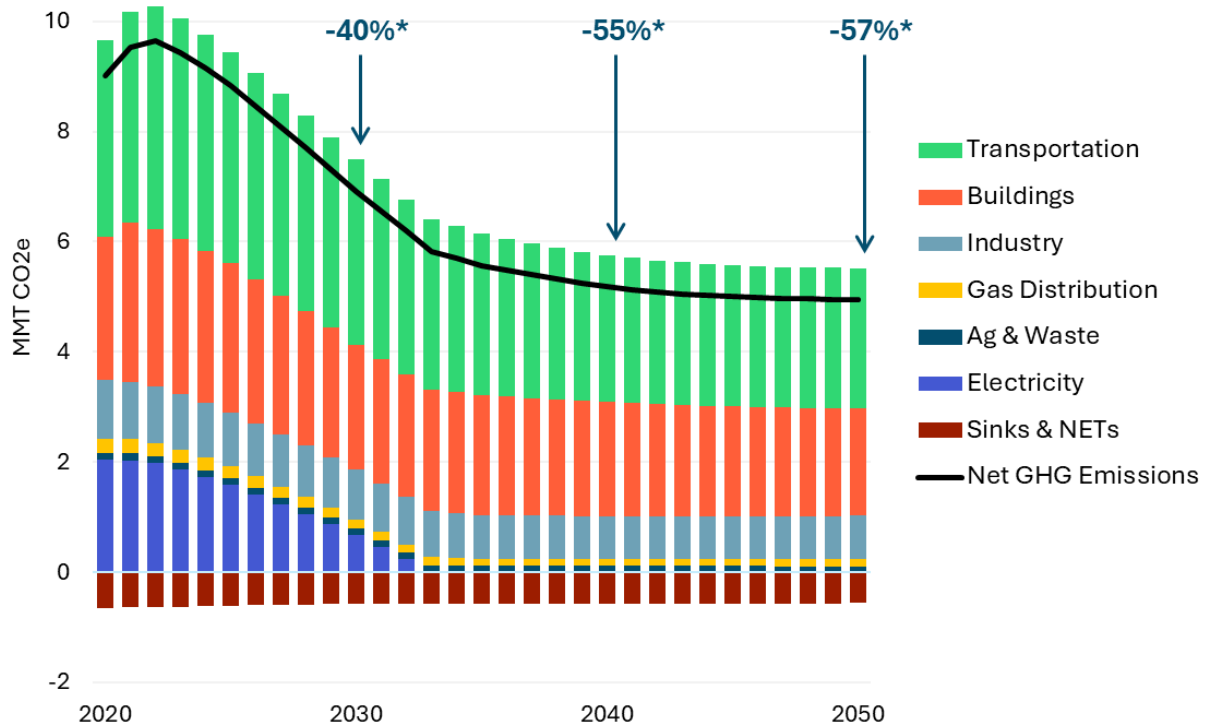
their fuel by 2030, continuing at the same rate until 2050, per the Biodiesel Heating Act. Energy efficiency also plays a role in building sector reductions, with weatherization retrofits reaching nearly 60% adoption by 2050.

- + **Industry.** Combustion emissions from heating in the industrial sector increase in the reference scenario due to projected industrial growth, reaching about 7% sectoral increase by 2030, 12% increase by 2040, and 18% by 2050, compared to 1990 levels. Other non-combustion industrial process emissions decrease slightly, primarily due to the reduction in hydrofluorocarbons (HFCs) in alignment with the Kigali Amendment to the Montreal Protocol.⁷¹
- + **Gas distribution.** Rhode Island's gas distribution sector will experience a sectoral emissions reduction of 48% by 2030, 64% by 2040, and 63% by 2050 compared to 1990 levels. Emissions reductions are driven by RIE's Leak Prone Pipe replacement schedule out to 2035. Note that the gas distribution category in Rhode Island's Inventory only accounts for emissions resulting from methane leakages in the distribution phase and does not include emissions resulting from the combustion of gas, or upstream (out-of-state) emissions.
- + **Agriculture & waste.** After 2020, there are no emissions reductions assumed in the agricultural sector due to hard-to-decarbonize end-uses and historical trends. By 2048, solid waste emissions are phased down to zero after the Central Landfill is expected to close in 2038, which is consistent with the 2016 RI GHG Reduction Plan. Overall, waste emissions decrease by 64% in 2030, 65% in 2040, and 70% in 2050 compared to 1990 levels.
- + **Electricity.** The largest contribution to reference scenario emissions reductions in Rhode Island are expected in the electric sector with 77% sectoral emissions reduction in 2030, 100% reduction in 2040, and 100% reduction in 2050, compared to 1990 levels. The large reduction in the electric sector is driven by Rhode Island RES, which requires 100% renewable energy procurement or REC purchases by 2033. This means that after 2033, all electricity in Rhode Island is considered zero-emission.
- + **Sinks and NETs.** There is a slight reduction in sequestration from carbon sinks by 2050 due to deforestation assumptions as laid out in the RI 2020 Forest Action Plan. No NETs are utilized in the reference scenario.⁷²

⁷¹ <https://www.state.gov/u-s-ratification-of-the-kigali-amendment/>

⁷² Rhode Island Department of Environmental Management and Division of Forest Environment. 2020 Forest Action Plan. <https://dem.ri.gov/sites/g/files/xkgbur861/files/programs/bnatres/forest/pdf/forest-action-plan/forest-action-plan.pdf>

Figure 15. Reference Scenario GHG Emissions 2020-20250



* compared to 1990 GHG emissions levels

Despite the progress made in the Reference scenario under existing policy mechanisms, additional measures will be required to achieve Rhode Island's Act on Climate mandate by 2030, 2040, and 2050. The Reference scenario misses emissions targets by .55 MMT CO₂e in 2030, 2.87 MMT CO₂e in 2040, and 4.95 MMT CO₂e in 2050, indicating that more aggressive mitigation action will be needed, particularly in the buildings, transportation, and industrial sectors in later years. Achieving compliance with 2040 and 2050 targets will require acceleration of mitigation measures between 2025 and 2040, especially considering the significant lag time between annual sales increases and subsequent changes to stock penetration.

Methane leakage from the gas distribution system

Following EPA guidance and aligning with the methodology from the state's GHG Inventory, methane leakage in the state of Rhode Island is estimated using reported gas consumption and emissions factors associated with different material types of gas distribution mains and services. This methodology assumes that as natural gas is distributed to end-use customers, a certain percent of gas leaks into the atmosphere in the form of methane (CH₄), therefore contributing to GHG emissions. In Rhode Island's accounting framework, the impact of methane leakage on emissions is calculated for in-state emissions only (excluding out-of-state supply chain impacts) over a 100-year time period (using a 100-year GWP).

Distribution system materials such as cast iron and unprotected steel, that today make up about 30% of mains in Rhode Island, are considered “leak-prone” and therefore have a significantly higher emissions factor than material types such as plastic and protected steel. Therefore, as RIE continues to replace leak-prone-pipe as part of its ISR program, emissions from the gas distribution system are expected to decline under the state’s accounting framework.

Recent studies have indicated that leakage from oil and gas systems may be higher than currently reported through inventories. For example, Weller et al. (2020) estimated that national methane emissions from the gas distribution system were approximately five times greater than reported through EPA inventories.⁷³ A study published in PNAS in 2021 found that atmospheric methane measurements in the Boston area over 8 years were three times larger than calculated by usage-based inventories, observing no changes in emissions despite efforts to replace leak-prone pipes.⁷⁴

It is important to note that detailed measurement reports of methane leakage associated with the distribution system are currently lacking. The only widely available measure of potential leaks reported by utilities is called “Lost and Unaccounted for Gas (LAUF)”, which represents the difference between gas purchased and gas sold. However, studies have criticized the LAUF metric, arguing that it includes noise created by differences in the timing of measurements, variations in temperatures, meter inaccuracies and accounting errors.⁷⁵

The uncertainty related to methane leakage, including potential impacts from unreported sources such as gas meters and indoor appliances, warrants continuous consideration and focus for further study.

Decarbonization Scenario Emissions

All decarbonization scenarios are designed to meet the emissions targets defined by Rhode Island’s Act on Climate under Rhode Island’s current GHG accounting framework. In addition, as a result of keeping most non-heating measures constant across scenarios, all pathways reach similar gross emissions in 2030, 2040, and 2050 by sector (see Table 8). That is, the gross emissions levels in 2040 in the residential sector for the High Electrification pathway is equal to the gross emissions levels in 2040 in the residential sector for the Continued Use of Gas pathway, but the primary measures employed to achieve those emissions reductions vary across pathways.

⁷³ Weller, Z., Hamburg, S., von Fisher, J. (2020). A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. *Environ. Sci. Technol.* 2020, 54, 14, 8958–8967

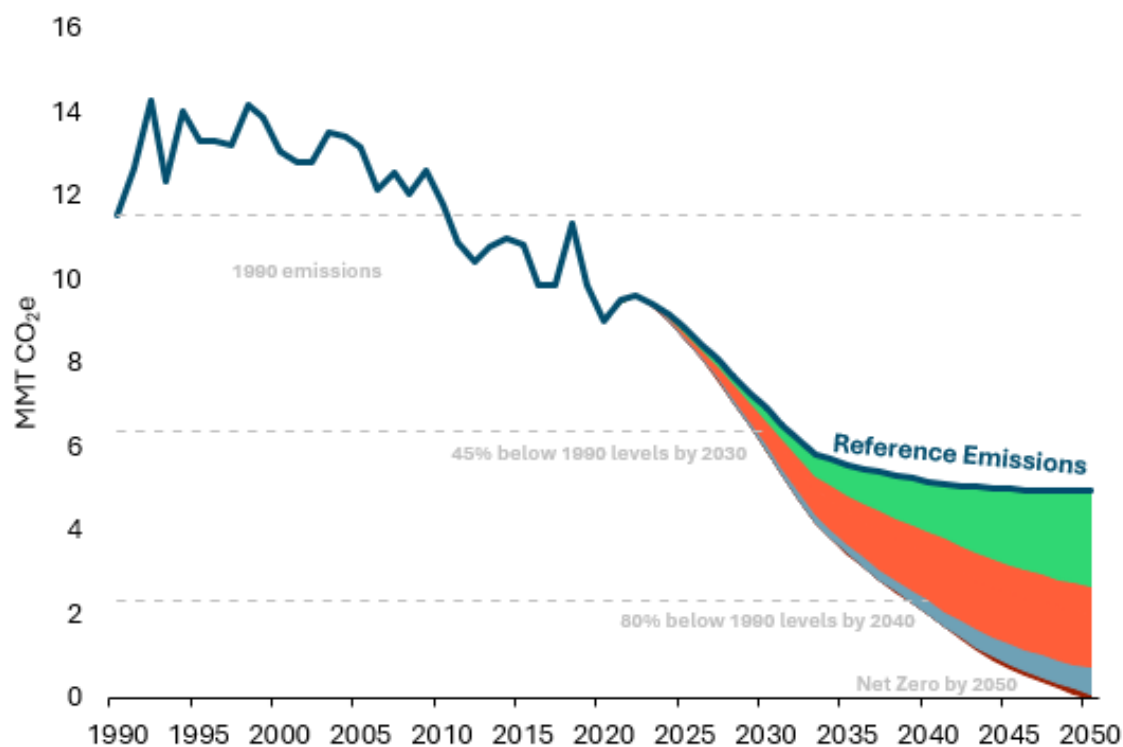
⁷⁴ Sargent, M., Floerchinger, C., McKain, K., Wofsy, S. 2021. Majority of US urban natural gas emissions unaccounted for in inventories. *Proc Natl Acad Sci U S A.* 2021 Nov 2;118(44):e2105804118. doi: 10.1073/pnas.2105804118

⁷⁵ See, for example: National Bureau of Economic Research (2018). Price regulation and environmental externalities: evidence from methane leaks. https://www.nber.org/system/files/working_papers/w22261/w22261.pdf

Table 8. Gross Sectoral Emissions Reductions by 2050

Sector	Emissions Reductions Compared to 1990 Baseline Across All Scenarios (%)
Transportation	-94%
Buildings	-100%
Industry	-84%
Gas Distribution	-63%
Agriculture & Waste	-66%
Electricity	-100%

Figure 16. Emissions Reductions in All Mitigation Scenarios



Emissions reductions from sector:

Transportation

Buildings

Industry

Gas distribution

Sinks & NETs

- + Transportation.** Across all decarbonization scenarios, transportation sector emissions decrease by 94% below 1990 levels by 2050. Emissions reductions are driven by Rhode Island's compliance with ACCII, which requires that 100% of new LDV sales are zero-emission by 2035, and ACT, which requires an aggressive increase in MHDV ZEV sales by 2035, with specific sales shares driven by truck class.

- + **Buildings.** Across all decarbonization scenarios, building sector emissions decrease nearly 100% below 1990 levels by 2050. The specific measures that drive these emissions reductions vary by scenario. For scenarios with high levels of electrification, all-electric and hybrid heat pump adoption contributes significantly to emissions reductions – particularly after 2033 when the electric grid is carbon neutral. In the High Electrification and Alternative Heat Infrastructure scenarios, networked geothermal also plays a role in driving down emissions by 2050. Renewable fuels are blended into remaining fuel supply at varied levels across scenarios, with higher levels in the scenarios that maintain a larger reliance on natural gas by 2050. In the Continued Use of Gas scenario, a significant share of emissions reductions is attributable to the use of renewable fuels.
- + **Industry.** Across all decarbonization scenarios, emissions associated with industrial activities decrease by approximately 84% below 1990 levels. The industrial sector decarbonizes through electrification or fuel-switching (e.g., dedicated hydrogen) within specific subsector processes, as feasible. Subsector processes that are considered to have high electrification potential include those where energy is used for conventional boilers, cogeneration, CHPs, and HVAC. Hard-to-electrify end-uses are those in which energy is used for high-temperature process heat.
- + **Gas distribution.** Across all decarbonization scenarios, emissions associated with the gas distribution system decrease 63% below 1990 levels due to reduced methane leakage from Rhode Island Energy’s LPP replacement program.
- + **Agriculture & waste.** Across all decarbonization scenarios, emissions from agriculture and waste decrease by approximately 66% below 1990 levels. Agriculture, waste, and wastewater emissions follow the same trajectory in decarbonization scenarios as in the reference scenario.
- + **Electricity.** Across all decarbonization scenarios, the electricity sector reaches 100% gross emissions reductions by 2033. There are no additional emissions reductions from the electric sector compared to the reference scenario, given compliance with the RES is consistent. However, variations in electric load growth across scenarios will result in differences in the amount of renewable energy procured, as further discussed in Chapter 4.
- + **Sinks & NETS.** Across all decarbonization scenarios, natural carbon sinks provide about 0.61 MMT CO₂e reduction by 2050. Carbon sequestration from natural sinks is slightly higher in mitigation scenarios than Reference, because it is assumed that there is no net forest, wetland, or cropland loss after 2030, in line with the 2016 RI GHG Reduction plan. About 0.15 MMT CO₂e of NETs are used across all scenarios to reach AoC emissions targets without relying on expensive low-carbon fuel blending.

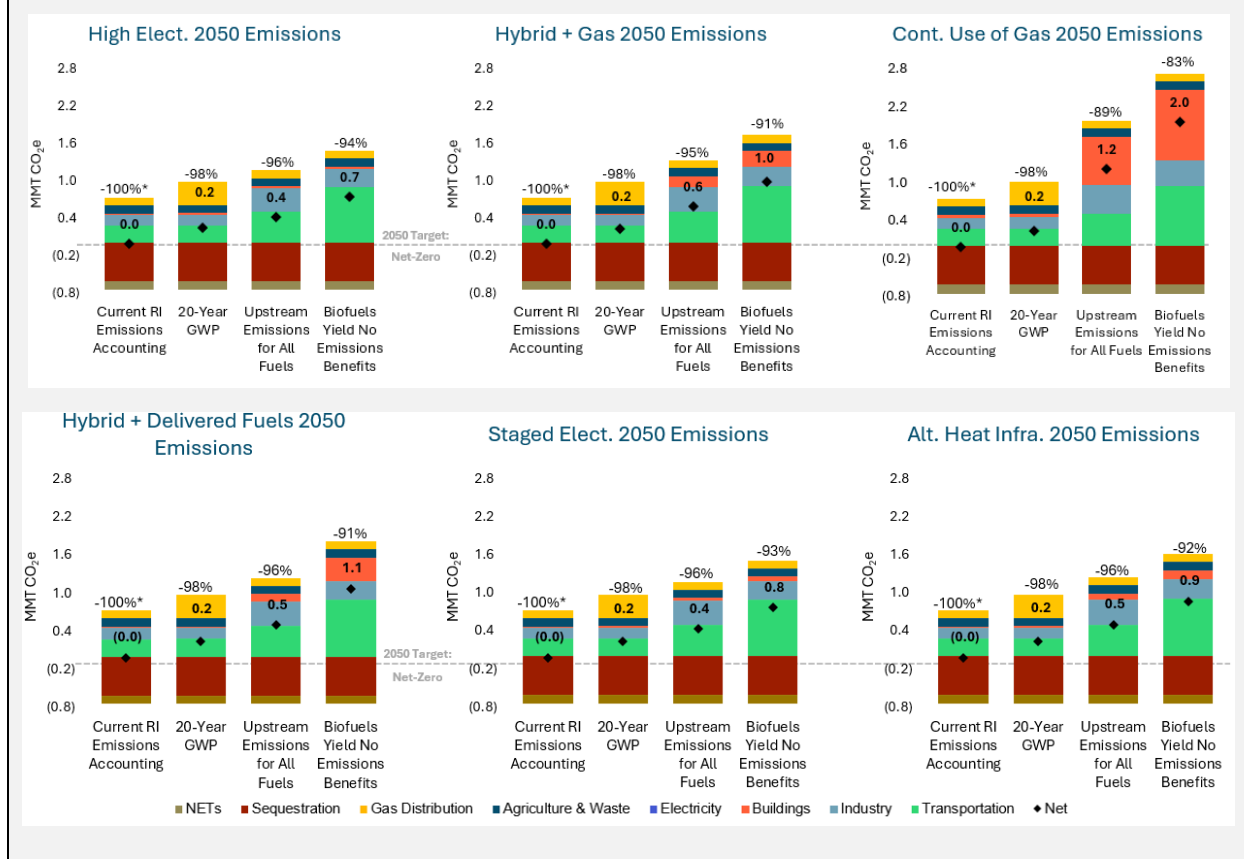
GHG emissions accounting methodology sensitivities

This study uses the Rhode Island state emissions inventory as its primary basis for developing an emissions baseline and emissions accounting. Through sensitivity analysis, E3 estimated the impact on remaining emissions if Rhode Island were to adopt alternative GHG accounting frameworks, including different GWP parameters, upstream emissions and zero emissions benefits associated with renewable fuels. This analysis finds that pathways that rely on higher levels of renewable fuels would have larger emissions impacts under all sensitivities:

- + **20-year GWP.** If Rhode Island adopted an accounting framework that uses a 20-year GWP rather than 100-year (as is current practice in New York and Maryland), across most scenarios the state would miss AoC 2050 targets by approximately 2%. This is primarily due to methane leakages from the gas distribution system carrying an approximately 3x higher impact using a 20-year GWP. These impacts are similar across scenarios but would differ if future gas infrastructure replacements are avoided or parts of the system can be decommissioned. Note that this analysis assumes the level of methane leakage derived from the current emissions accounting framework.
- + **Upstream emissions for all fuels.** The current GHG accounting methodology does not consider upstream (out-of-state) emissions for fossil fuels or renewable fuels. If Rhode Island was to consider upstream emissions for both fossil and renewable fuels, scenarios that rely on higher levels of fuels, such as Continued Use of Gas, would fall short of the 2050 target by 11%. Scenarios that rely on higher levels of electrification (e.g. High Electrification, Staged Electrification) would fall short of the 2050 AoC targets by 4%.
- + **Renewable fuels have no emissions benefit.** Under the existing emissions accounting framework, Rhode Island considers renewable fuels to be carbon neutral, assuming that these fuels take up an equal amount of CO₂ of their lifetime as they combust at end-of-life. As a bounding exercise recommended by the TWG, E3 estimated the impact on emissions if, hypothetically, the combustion of renewable fuels emitted the same levels of emissions as their fossil counterparts. This analysis finds that under this assumption, all scenarios would fall short of the 2050 targets, but to varying extents. Scenarios that rely on higher levels of electrification (e.g. High Electrification, Staged Electrification) would miss 2050 AoC targets by 6%, while the Continued Use of Gas pathway would miss targets by 17%.

Overall, under different emissions accounting frameworks, the pathways that utilize higher levels of renewable fuels would leave higher levels of emissions by 2050. The assumptions that were used to calculate these results are outlined in Appendix A.1.

Figure 17. Remaining Emissions in 2050 Under Alternative Accounting Frameworks



Impact on Technology Adoption

Mitigation scenarios achieve the Act on Climate through a distinct mix of technology adoption in the residential and commercial sectors, a large ramp-up of zero-emission vehicles in the transportation sector, and a mix of efficiency, electrification, and low-carbon fuel switching in the industrial sector. While the specific mix of technologies varies based on the key research question of each scenario, a rapid shift toward decarbonized technology adoption will be required across all pathways in order to reach Rhode Island's ambitious climate goals.

Adoption Of Heating Technology In The Building Sector

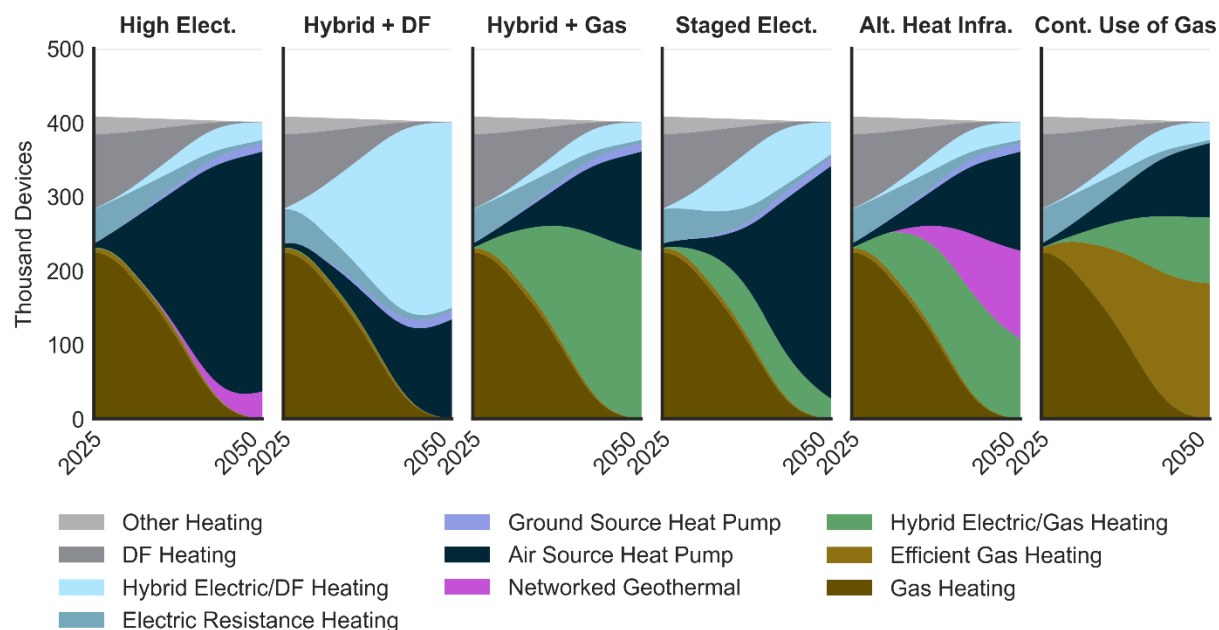
Across all pathways, there is a significant transformation in the way both residential and commercial buildings use energy. All end-uses – such as space heating, water heating, cooking, and clothes drying – undergo a notable transition from fossil-fuel powered equipment to decarbonized technologies. While space heating is the largest focus of the Technical Analysis, all building end-uses will experience significant shifts between today and 2050. Across all scenarios, water heating, cooking, and clothes drying transition to all-electric or efficient gas equipment at approximately the same pace as space heating conversions, with the technology transitions specific to each scenario's

key research question. The focus of the rest of this chapter is on space heating; space heating is the building end-use that consumes the most energy, thus the transformation of how buildings are heated is a critical component in the future of Rhode Island's natural gas system and in the path to decarbonizing Rhode Island's economy.

Figure 18 below shows how space heating technology will change over time in the residential sector under all six scenarios. Figure 18 below shows how space heating technology will change over time in the residential sector under all six scenarios. Although building electrification occurs within all pathways, the level and composition of electrification varies:

- + The High Electrification, Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup, Staged Electrification, and Alternative Heat Infrastructure achieve similar levels of electric space heating, utilizing a mix of different heat pump technologies. Electrification in the High Electrification and Staged Electrification pathways is made up of primarily all-electric ASHPs by 2050. Buildings in the Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup pathways have the same total number of heat pumps in 2050 as High Electrification, but the electrification relies on hybrid heat pumps with either delivered fuel or gas backup.
- + The Alternative Heat Infrastructure pathway has the same total number of heat pumps as the High Electrification pathway, but about 30% are comprised of networked geothermal systems. In this pathway, it is assumed that approximately 145,000 of total residential gas customers would transition to networked geothermal systems between 2027 and 2050, with investments prioritized in moderate to high population density areas.
- + The Continued Use of Gas pathway assumes 25% of buildings adopt all-electric heat pumps, and 30% converts to hybrid heating with gas or delivered fuel backup. Remaining buildings are expected to adopt efficient gas heating appliances.

Figure 18. Residential Household Space Heating Equipment Adoption⁷⁶



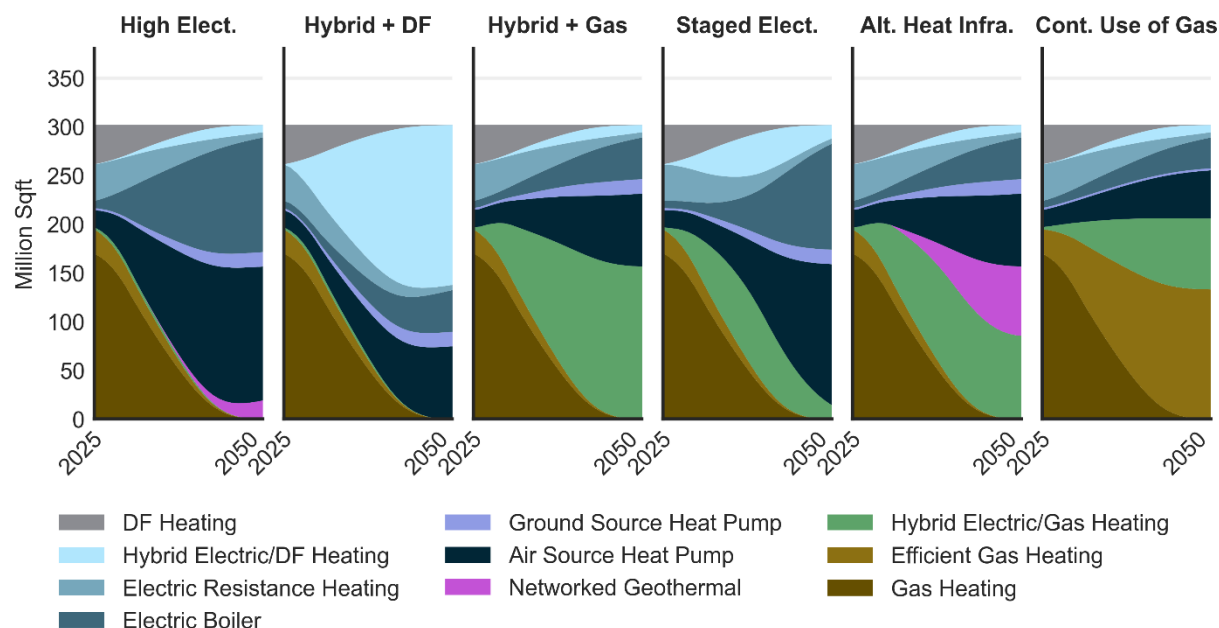
In order to reach the goals laid out in the Act on Climate, Rhode Island will need to significantly increase annual adoption of decarbonized heating technologies. In scenarios focused on higher levels of electrification, annual heat pump sales exceed 25,000 devices in 2040, nearly five times higher compared to the reference scenario and approximately ten times higher than today's adoption levels. Scenarios with lower levels of electrification still see adoption levels by 2040 that are twice as high compared to the reference scenario, and five times higher compared to today's annual heat pump sales.

Figure 19 below shows how space heating technology stocks will change over time in the commercial sector under all six mitigation pathways. The transition of commercial space heating equipment is similar to the transition in the residential sector within the same pathway, with differences primarily in the ratio between electric boilers and heat pumps, where commercial buildings with existing gas or oil boilers convert to electric boilers rather than ASHPs when undergoing electrification.⁷⁷

⁷⁶ "Other Heating" includes LPG furnaces and wood stoves.

⁷⁷ E3 set an expert-guided cutoff that a heater must be below 50-tons to be electrifiable to a heat pump. From E3's review of the Commercial Buildings Energy Consumption Survey (CBECS), no commercial boilers were below 50-tons. Therefore, E3 determined that commercial buildings with fossil fuel-powered boilers would electrify to electric boilers rather than ASHPs.

Figure 19. Commercial Space Heating Equipment Adoption



Energy Efficiency and Weatherization

Energy efficiency is a critical component of all decarbonization strategies and will play an important role in Rhode Island's path to net zero emissions. As described in Appendix A.1, the Technical Analysis incorporates many forms of energy efficiency measures across multiple sectors, such as weatherization and building shell retrofits, building electrification, technology performance improvements, appliance standards and in-kind high-efficiency replacements (e.g., lighting upgrades), behavioral conservation and smart devices (e.g. programmable thermostats and lighting timers), and industrial manufacturing efficiency.

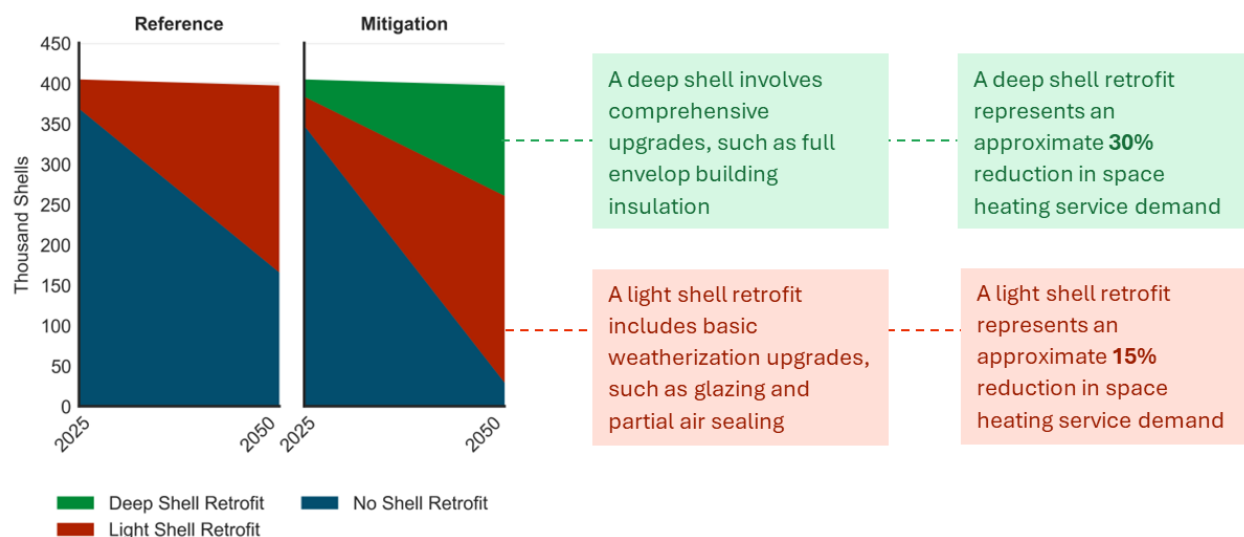
The rest of this section primarily focuses on the role of building energy efficiency, with a particular emphasis on weatherization and building shell adoption in decarbonizing the heating sector.

Energy efficiency in buildings – such as weatherization measures to improve the performance of a building envelope – directly reduces heating requirements, energy consumption, and electric load impacts of electrification, which can significantly reduce the need for additional electric infrastructure buildouts and/or the quantity of renewable fuels required. Building energy efficiency already plays a key role in Rhode Island's heating sector transformation through existing energy efficiency programs. For example, the EnergyWise Single Family Program (EWSF) assisted over 3,000 customers with energy efficiency measures – such as lighting and weatherization – in 2019 and the EnergyWise Income Eligible and Multifamily Program has served hundreds of multifamily facilities

across Rhode Island with measures such as common area and in-unit lighting.^{78,79} Given the impact of existing energy efficiency programs and the potential for future expansion, aggressive assumptions around weatherization adoption are incorporated into the reference scenario in addition to all decarbonization pathways.

Building shell and envelope assumptions deployed in the reference and decarbonization scenarios were supported by research from NV5, a technical engineering and consulting firm that leads the Technical Consultant team for the Rhode Island Energy Efficiency and Resource Management Council (EERMC) and represented EERMC on the TWG. Leveraging industry expertise and the Rhode Island Energy Efficiency Market Potential Study Refresh, NV5 developed set of assumptions regarding weatherization adoption rates under both reference and decarbonization scenario conditions for E3 to utilize in the Technical Analysis.⁸⁰ Adoption rates varied by building type (single family, multifamily, commercial) and fuel type (natural gas, oil, propane). Overall, it is estimated that nearly 60% of Rhode Island’s residential building stock will undergo light-touch energy efficiency retrofits by 2050 in the reference scenario, whereas decarbonization scenarios install an additional 35% of deep shell retrofits in residential homes (see Figure 20).

Figure 20. Building Shell Adoption Over Time



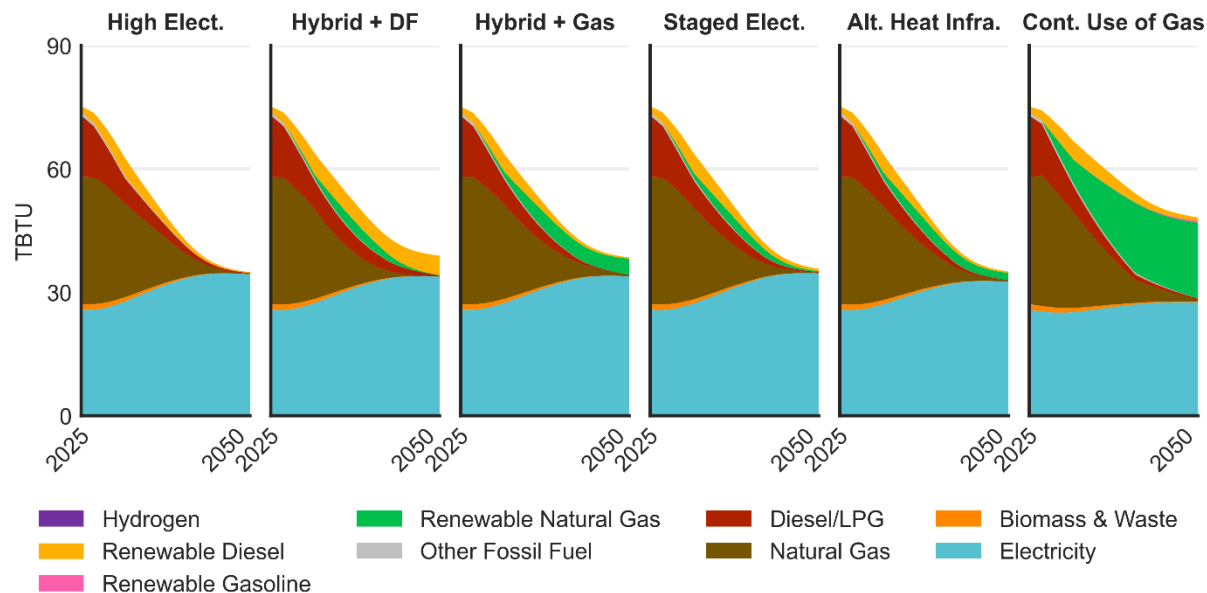
Energy efficiency in buildings, such as the weatherization measures discussed above, building electrification, technology performance improvements, appliance standards, and behavioral conservation lead to significant reductions in energy demand in buildings, as shown in Figure 21.

⁷⁸ Source: https://rieermc.ri.gov/wp-content/uploads/2020/10/ng-ri-ews-f-impact-and-process-comprehensive-report_final_04sept2020.pdf

⁷⁹ Source: https://rieermc.ri.gov/wp-content/uploads/2020/10/ng-ri-mf-impact-and-process-comprehensive-report_final_04sept2020.pdf

⁸⁰ Additional data sources listed include: NREL Data Lake, C&I Building Demographic Data, MA Clean Energy and Climate Plan, RIE/National Grid Program Performance Data

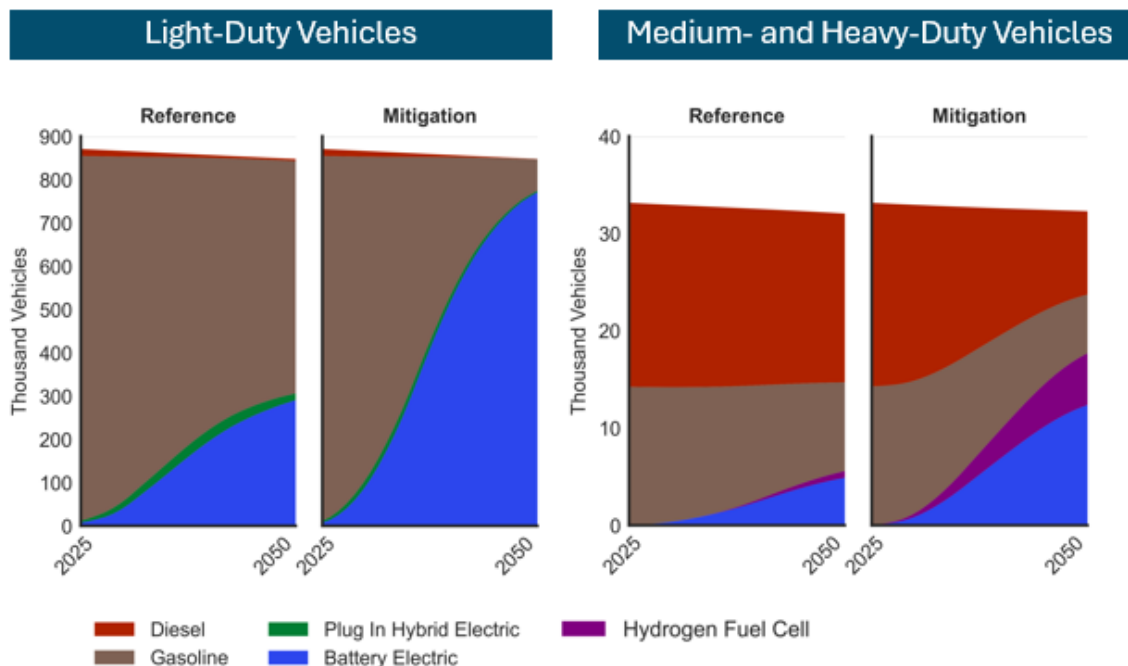
Figure 21. Energy Demand Reductions in Buildings as a Result of Efficiency and Electrification Measures



Transportation Sector Technology Adoption

Across all decarbonization scenarios, the Transportation sector experiences a drastic transition away from internal combustion engine (ICE) vehicles to zero-emission cars and trucks, as required by ACCII and ACT (see Figure 22). ACCII requires that 100% of new LDV sales will be ZEVs by 2035; in line with ACCII requirements, E3 assumed that the majority of LDV ZEVs will be battery electric by 2035, with a small portion of plug-in hybrid. ACT requires an aggressive increase in MHDV ZEV sales by 2035, with specific sales shares driven by truck class. While MHDVs will also transition away from ICE vehicles as required by ACT, MHDVs will experience lower levels of electrification than LDVs, with a modest portion converting to hydrogen fuel cell vehicles instead (also classified as ZEVs under ACT). Where MHDVs are not able to fully electrify, remaining fuel demand is blended with low-carbon fuel alternatives, such as renewable diesel.

Figure 22. LDV and MHDV Stocks Over Time



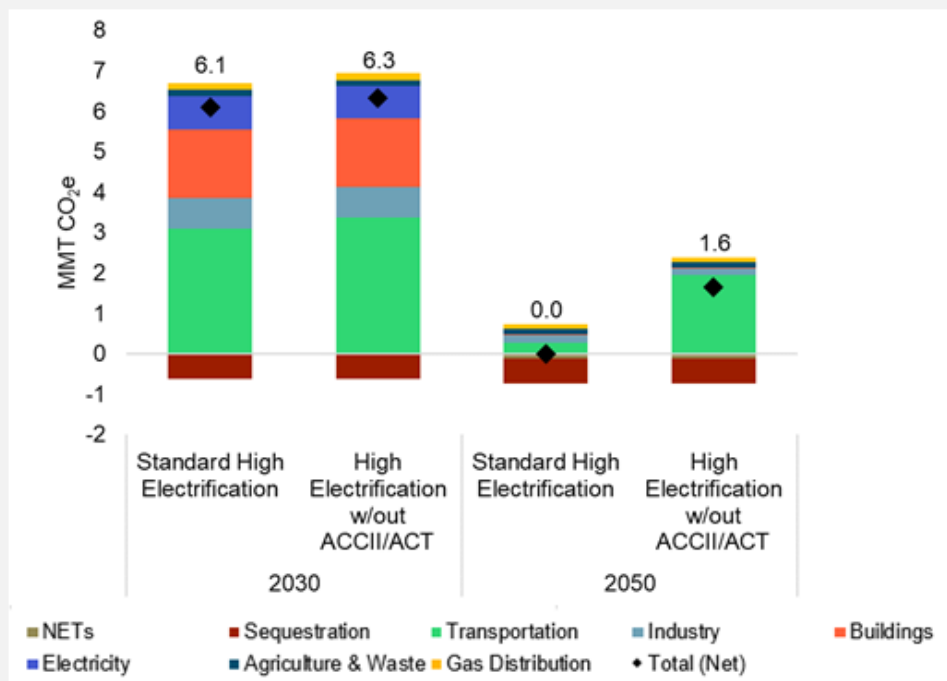
If the transportation sector does not electrify at the pace of ACCII/ACT, more action will be required in other sectors.

A key assumption in all decarbonization pathways is that Rhode Island will achieve compliance with ACCII and ACT, leading to significant emissions reductions in the transportation sector. E3 modeled a sensitivity onto this assumption that explores the action required in other sectors if the transportation sector does not electrify at the pace of ACCII/ACT. It is important to note that E3 did not model or assess the probability of Rhode Island meeting or not meeting the ACCII/ACT targets.

The sensitivity analysis shows that if achievement of ACCII/ACT is delayed, Rhode Island will require deeper measures to reach AoC targets, primarily in the long term. The 2030 AoC target can be met with accelerated building sector measures that are already required to facilitate longer term climate goals. For example, High Electrification would meet the 2030 target even if ACCII/ACT follows a slower trajectory in the short term. This is due to accelerated action in the buildings sector that was modeled in the Technical Analysis in order to set the state up for reaching longer-term emissions targets. However, by 2050, High Electrification will have approximately 1.65 MMT CO₂e remaining in 2050 without achievement of ACCII/ACT, thus missing the AoC target by about 14% (see Figure 23). If EV penetration is consistent with historical levels and the EC4 target (10% of stocks by 2050) instead of ACCII/ACT, RI will not meet the 2040/2050 AoC targets without higher renewable fuel blending or deeper measures in other sectors. In High Electrification, the buildings sector is completely electrified. Thus, if the ACCII/ACT is not achieved, higher renewable fuel blending in the Transportation sector will be required. In other

mitigation pathways, deeper building electrification measures can be adopted if the ACCII/ACT is not met.

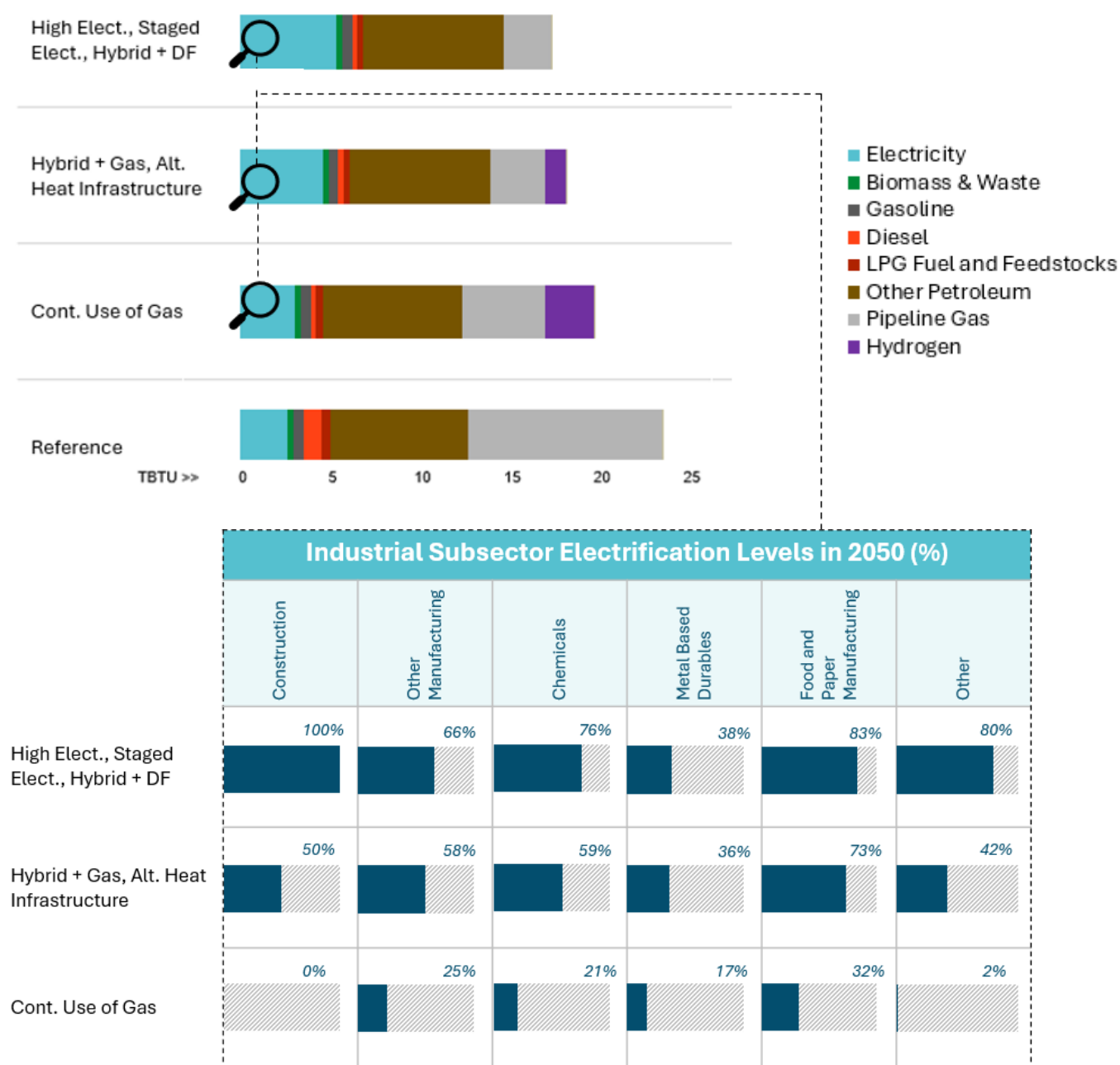
Figure 23. Remaining Emissions with and without ACCII/ACT (High Electrification Pathway)



Industrial Sector

Despite consistent levels of assumed economic growth, energy demand in the industrial sector declines across all scenarios (Figure 24) driven by continued efficiency improvement and varied reliance on electrification vs. fuel-switching. Scenarios with a larger focus on electrification and gas pipeline decommissioning (e.g., High Electrification, Staged Electrification, and Hybrid with Delivered Fuels Backup) electrify industrial end-uses as much as is technically feasible, while relying on renewable fuels – such as renewable natural gas – only in hard-to-electrify subsectors. Scenarios that rely more heavily on the maintenance of the gas system (e.g., Hybrid with Gas Backup, Alternative Heat Infrastructure, and Continued Use of Gas) electrify a smaller portion of industrial subsector processes, with a higher focus on pipeline gas – supplied by renewable fuels – and adoption of dedicated hydrogen.

Figure 24. Industrial Energy Demand (TBTU) and Subsectoral Electrification Levels in 2050



E3 used the Manufacturing Energy Consumption Survey (MECS) to determine the type and quantity of energy used by industrial subsectoral processes today. Subsector processes that are considered to have high electrification potential include those where energy is used for conventional boilers, cogeneration, CHPs, and HVAC. Hard-to-electrify end-uses are those in which energy is used for high-temperature process heat. Some processes, such as on-site transportation and machinery have less certain electrification potential. For the processes with less certain electrification potential, assumptions on levels of electrification varied by scenario (see Appendix A.1 for details).

Impact on Energy Demand

Statewide Energy Demand

The Technical Analysis shows that in order to reach climate targets, Rhode Island will need to significantly transform how it produces, supplies, and uses energy within all sectors of the economy. Across all pathways, final energy demand decreases between 40-50% compared to today by 2050 as a result of weatherization, appliance efficiency, and electrification, as seen in Figure 25 and Figure 26. Today, Rhode Island's energy system relies primarily on petroleum and natural gas, but by 2050 the reliance shifts to electricity and renewable fuels across all decarbonization scenarios. None of the pathways fully eliminate gas; those with high levels of electrification leave some gas usage in the industrial sector, while those with lower levels of electrification continue to rely on gas in buildings.

By 2050, 40-60% of final energy demand is served by electricity; scenarios with high levels of electrification see nearly doubling of electric load by 2050 compared to today's levels. By 2050, 50-70% of the fuel mix across pathways consists of renewable fuels, although the total amount of fuel is significantly reduced. In order to comply with state policy – such as the Biodiesel Heating Oil Act – and Act on Climate targets, the use of renewable fuels is required across all pathways, with the highest levels in the pathways with the lowest levels of electrification. Hybrid with Delivered Fuels Backup sees the highest level of renewable diesel adoption, while the Continued Use of Gas pathway utilizes the most renewable natural gas and hydrogen.

Figure 25. Statewide Energy Consumption Over Time by Fuel Type

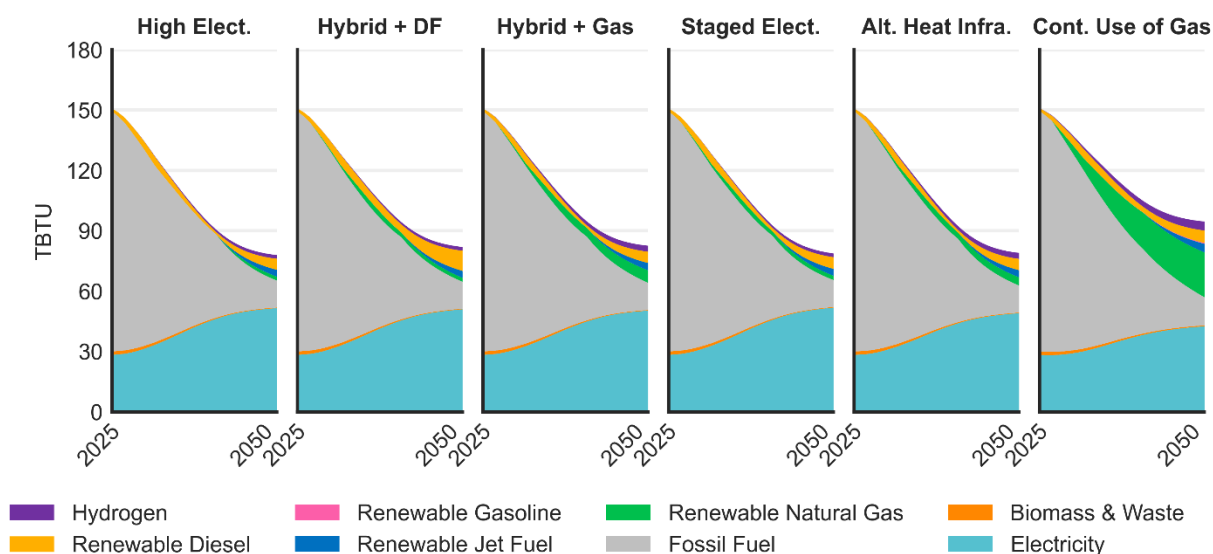
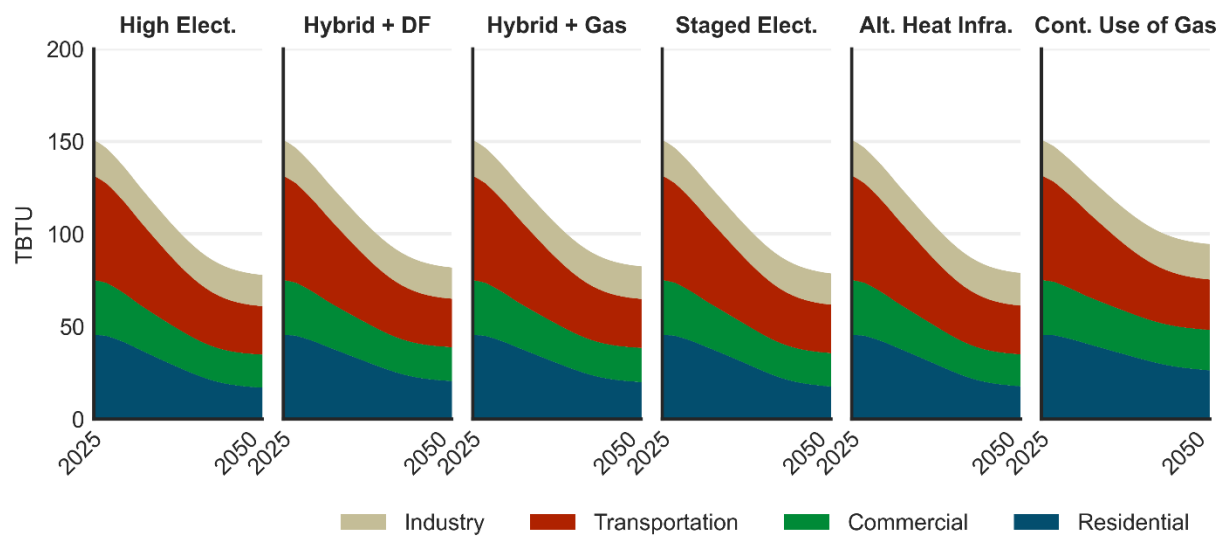


Figure 26. Sectoral Energy Consumption Over Time

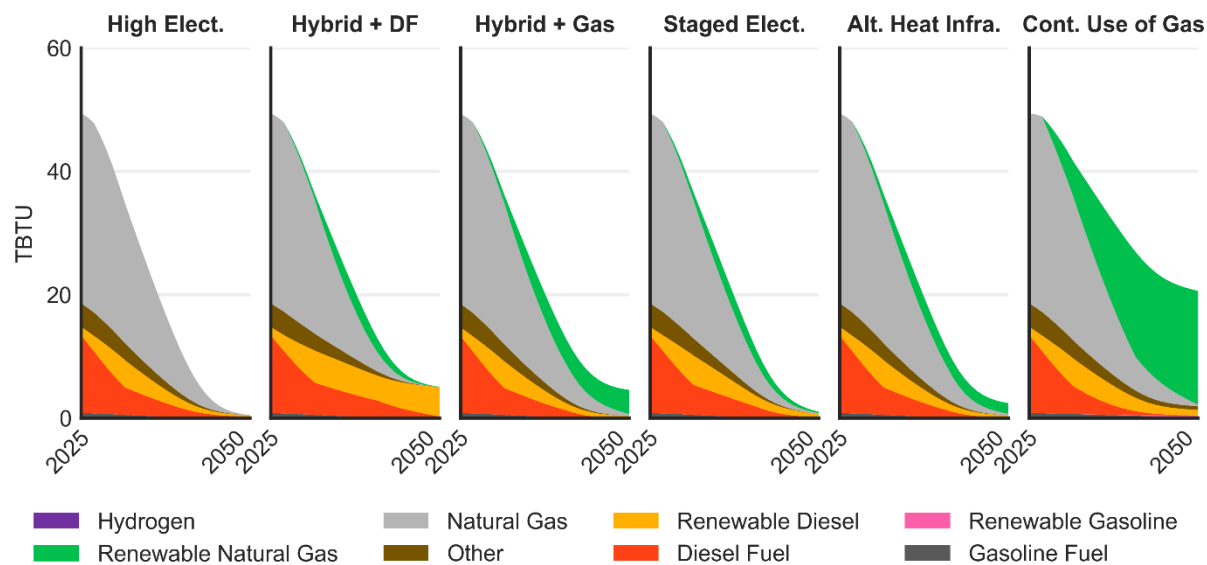


Use of Renewable Fuels in the Buildings Sector

Following Rhode Island’s GHG accounting framework, the Technical Analysis assumes that the combustion of renewable fuels contribute to gross emissions reductions. For simplicity, E3 refers to these types of fuels as renewable natural gas, renewable diesel or renewable gasoline, acknowledging that the source of the fuel may vary depending on factors as availability, policy and market mechanisms. From a technical perspective, renewable fuels can be derived through anaerobic digestion or gasification using various sources of biomass (forest residues, municipal solid waste, landfill gas, etc.) or synthetically using renewable hydrogen and captured carbon dioxide. The availability, commercialization and cost of these different production methodologies differs widely.

Renewable fuels are expected to play an increasingly important role in the buildings sector across scenarios. In the near-term in all scenarios, renewable diesel gradually replaces the use of fuel oil for heating purposes to comply with the Biodiesel Heating Act. In addition, all scenarios except for High Electrification start to blend in small amounts of renewable natural gas as a way to reduce emissions. Longer term, renewable natural gas is primarily used as a supply-side measure in the Continued use of Gas scenario, and to a lesser extent in the Hybrid with Gas Backup scenario. In contrast, the Hybrid with Delivered Fuels Backup scenario relies more heavily on renewable diesel to supply heat on cold winter days. Further implications of the use of renewable fuels are discussed in Chapter 5.

Figure 27. Transition to Renewable Fuels in the Building Sector across Scenarios



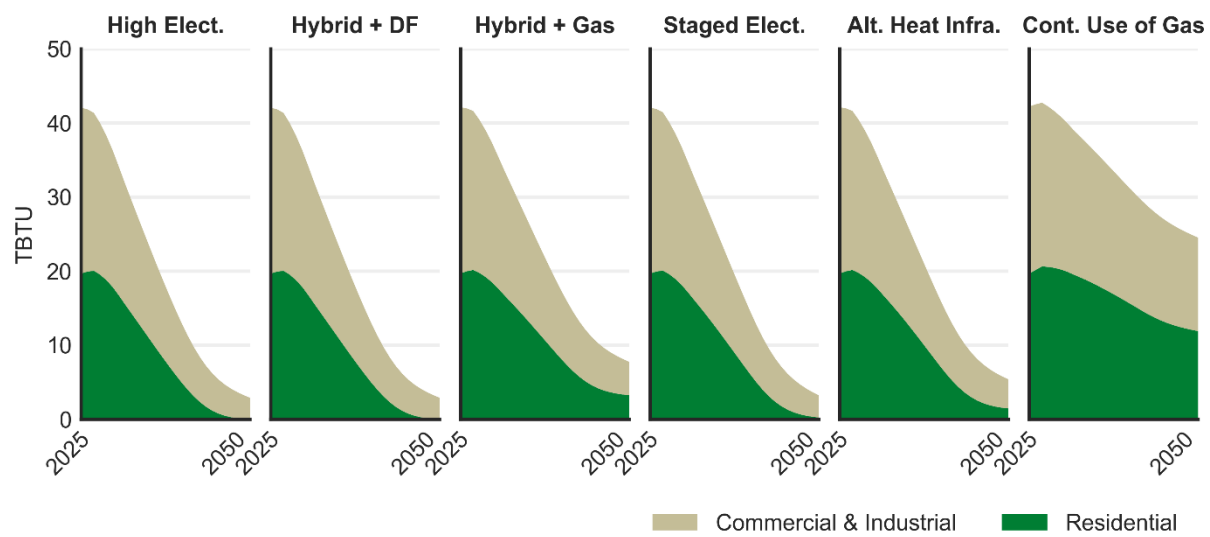
Impact on the Gas System

Each of the scenarios results in a transformation of the gas system, either through demand-side measures in the form of electrification or through supply-side measures in the form of renewable gas blending. These decarbonization strategies have different impacts on the role and the use of the gas delivery system and gas supply. Some pathways, such as High Electrification and Hybrid with Delivered Fuels Backup, see a complete phase out of natural gas for residential and commercial customers, while other pathways rely on gas infrastructure to meet peak space heating needs in buildings during the coldest hours of the year (Hybrid with Gas Backup) or continue to use the gas system to deliver a blend of renewable gases (Continued Use of Gas) to achieve Rhode Island’s climate goals.

Transformation Of Gas Throughput And Customer Base

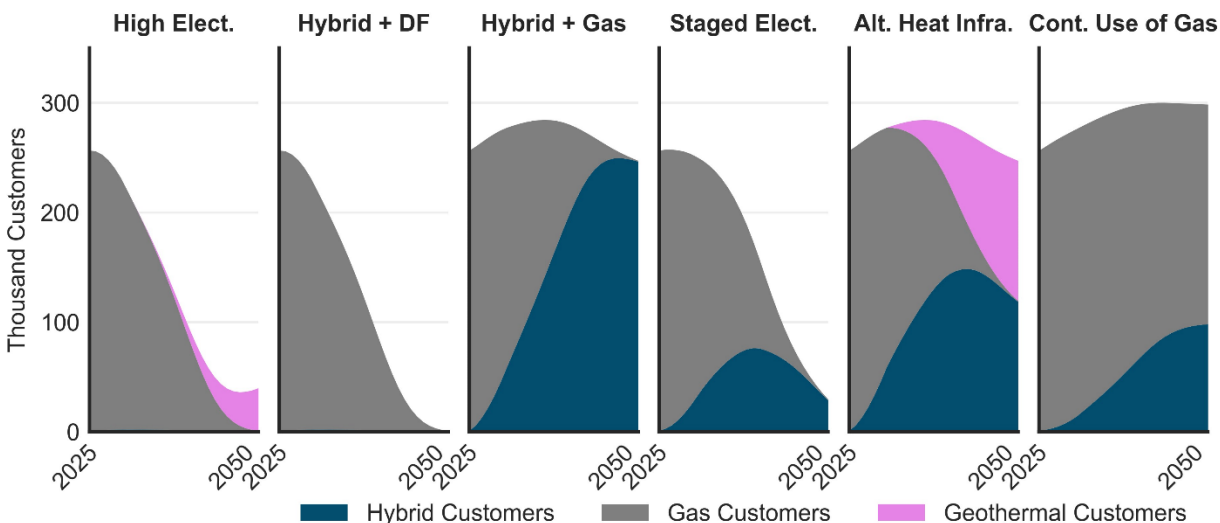
The decarbonization scenarios see a substantial decline in delivered gas volumes; across all pathways, gas throughput decreases between 45-95% by 2050 because of efficiency and electrification, as shown in Figure 28. Some levels of gas throughput remain in the commercial and industrial sectors, particularly to deliver gas to “hard-to-decarbonize” applications in the industrial sector. The Continued Use of Gas pathway maintains the highest level of gas throughput but still sees declines compared to today due to efficiency improvements in buildings and levels of hybrid electrification. Pathways with high levels of electrification, such as High Electrification and Hybrid with Delivered Fuels Backup, reduce gas throughput to almost zero by 2050, whereas pathways relying on hybrid gas heating systems require some gas supply by 2050, but at much reduced levels compared to today’s supply.

Figure 28. Gas Throughput by Sector across Decarbonization Scenarios



The transition of the gas customer base (Figure 29) is a key variable across decarbonization pathways. Scenarios with high levels of electrification, such as High Electrification, Hybrid with Delivered Fuels and Staged Electrification, see a steep decline in the gas customer base as customers convert to all-electric appliances. Pathways with hybrid heating solutions with gas backups and networked geothermal maintain similar levels of customers, either on the gas system directly or as networked geothermal customers. It is assumed that networked geothermal customers will be customers of a utility-type entity that would invest in and build the geothermal systems. Finally, the Continued Use of Gas pathway sees an increase in the number of gas customers, primarily as a result of fuel oil-to-gas conversions.

Figure 29. Gas Utility Customers across Decarbonization Scenarios

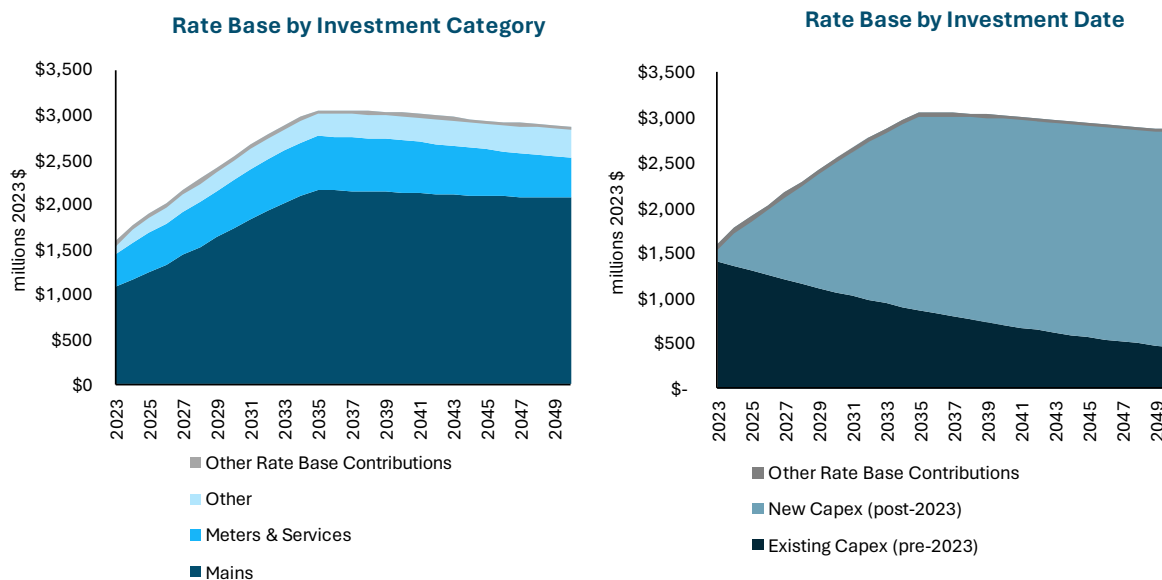


Gas Revenue Requirement

Given the varying roles of the gas distribution system to deliver gas and serve customers under different pathways, E3 analyzed the capital costs of replacing and maintaining gas system infrastructure and the operational & maintenance (O&M) costs of serving customers.

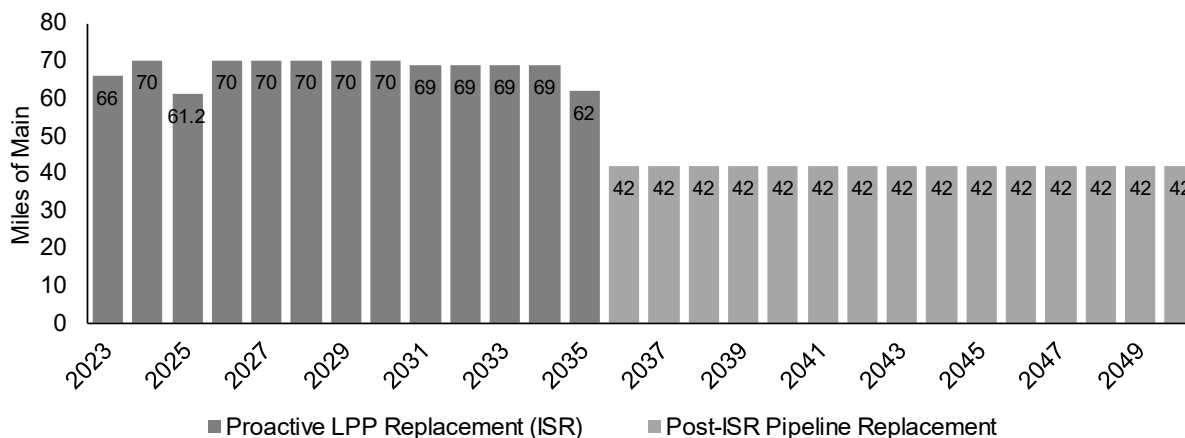
E3 forecasted RIE’s rate base — the total value of RIE’s assets — by assessing investments already on the books and evaluating future capital costs required to replace existing infrastructure and build new infrastructure (see Figure 30). E3 categorizes RIE’s capital investments that make up its rate base into three categories: Mains, Meters & Services, and Other. The Mains category includes investments in main distribution pipeline, which is largely comprised of RIE’s investment in LPP replacement. Meters & Services includes investments in service lines that directly connect mains to customers’ homes and businesses and the meters that serve these customers. The “Other” asset category reflects additional, non-pipeline capital investments, such as regulator station upgrades, LNG facilities and office equipment. Other rate base contributions include construction works in progress, materials and supplies, cash working capital, deferred tax, and several other small contributing categories.

Figure 30. Rate Base under Reference Scenario



Much of RIE’s recent and forecasted gas system investment stems from the ISR program, which encompasses LPP replacement. These investments are included in the Mains component in Figure 30. Figure 31 shows the number of main pipeline miles that RIE expects to replace through 2050. RIE plans to replace approximately 70 miles of LPP per year until 2035 and then expects to reduce the replacements to approximately 42 miles per year through 2050, mostly representing the replacement of plastic mains. Under the current regulatory framework, the investments are estimated to be the same across decarbonization pathways.

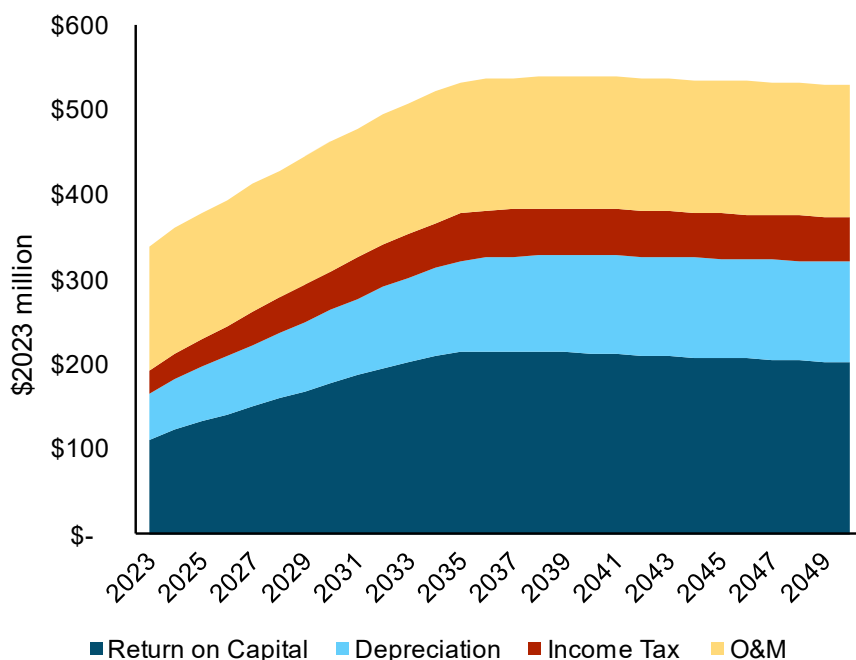
Figure 31. Projected Miles of Pipeline Main Replacement



The investments planned under the ISR program, additional infrastructure investments, and investments in new customer connections contribute to RIE’s rate base, on which RIE earns a return. In addition to RIE’s return on capital, depreciation expense, income tax, and O&M expenses make up RIE’s revenue requirement (see Figure 32), which is forecasted to grow under the reference

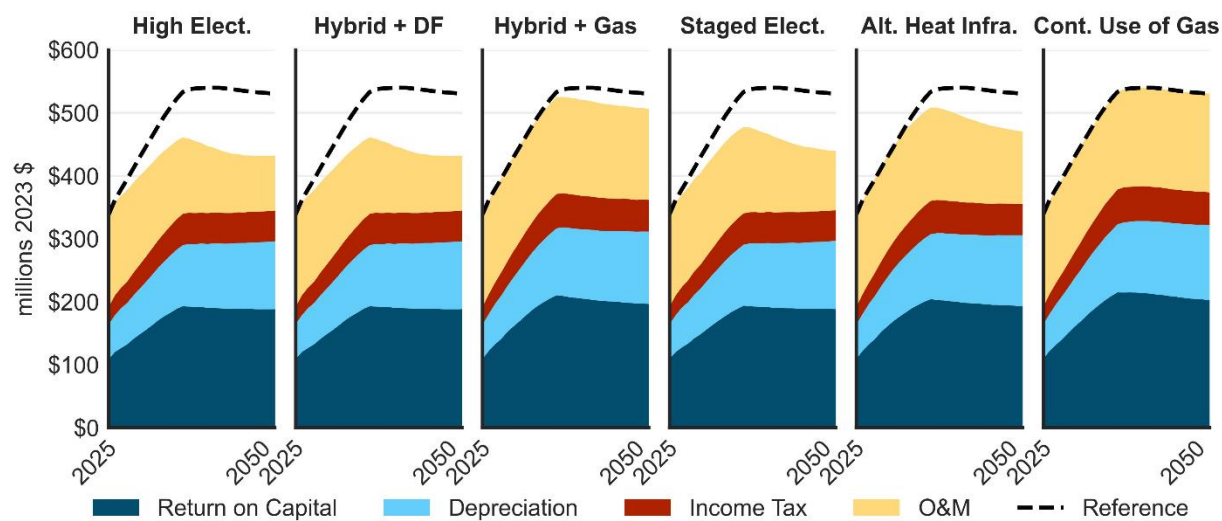
scenario, primarily because of future capital expenditures. In addition to RIE’s return on capital, depreciation expense, income tax, and O&M expenses make up RIE’s revenue requirement (see Figure 32), which is forecasted to grow under the reference scenario, primarily because of future capital expenditures.

Figure 32. Revenue Requirement under Reference Scenario



Under the current regulatory framework, capital investments required to maintain the distribution system, such as the those under the ISR program, are forecast to be the same across decarbonization pathways. However, the differences in gas customer counts alter the infrastructure investments designated for new customers and the O&M costs required to serve those customers. Customer additions require service and meter infrastructure investments and sometimes main line extensions. Customer additions and departures result in varying O&M expenses reflecting the variable costs to serve customers. Figure 33 shows how the revenue requirement differs across pathways due to customer additions and departures. This figure shows that scenarios that do not assume additional customer connections, such as High Electrification and Hybrid with Delivered Fuels, reduce annual costs of the gas system by approximately 18% by 2050 compared to a reference scenario.

Figure 33. Revenue Requirement under Decarbonization Scenarios

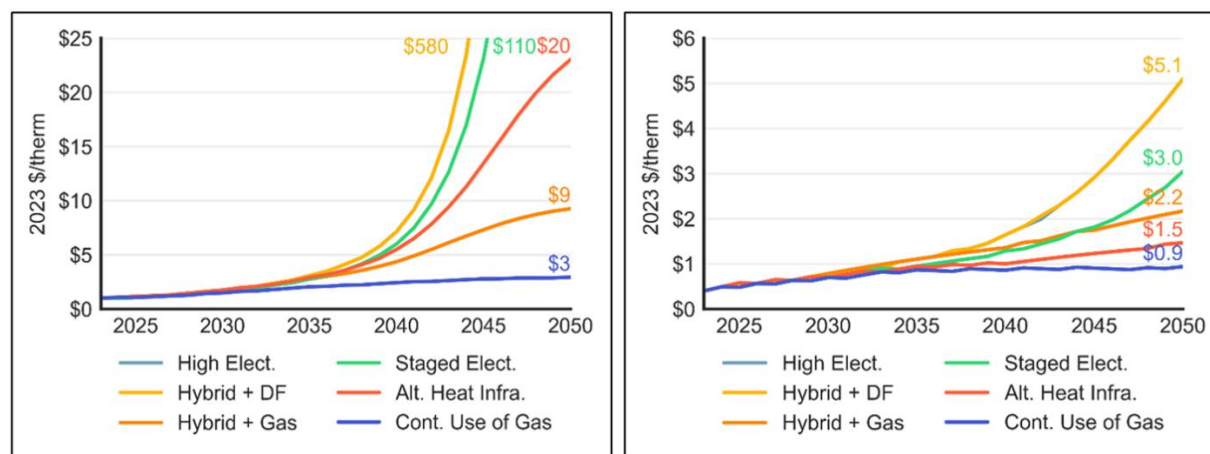


Impact On Delivery Rates

RIE's revenue requirement is recovered through customer delivery rates where the majority of costs are recovered through a volumetric charge. At the highest level, this means that the total costs of the gas system are divided by gas throughput on the system to determine the costs for a customer *per unit of gas used*.⁸¹ Although there are variations in RIE's revenue requirement across scenarios, all scenarios experience a decline in gas throughput while the costs of the system continue to rise. Under the current regulatory framework, this dynamic results in rapidly escalating long-term gas delivery rates for residential, commercial, and industrial customers in nearly all decarbonization scenarios. As shown in Figure 34, gas delivery rates rise substantially, especially after 2035, in pathways where gas throughput declines dramatically.

⁸¹ A more detailed explanation of how gas rates are determined is provided in Appendix A.2.

Figure 34. Gas Rates across Decarbonization Scenarios. Left: residential rates. Right: commercial and industrial (C&I) rates



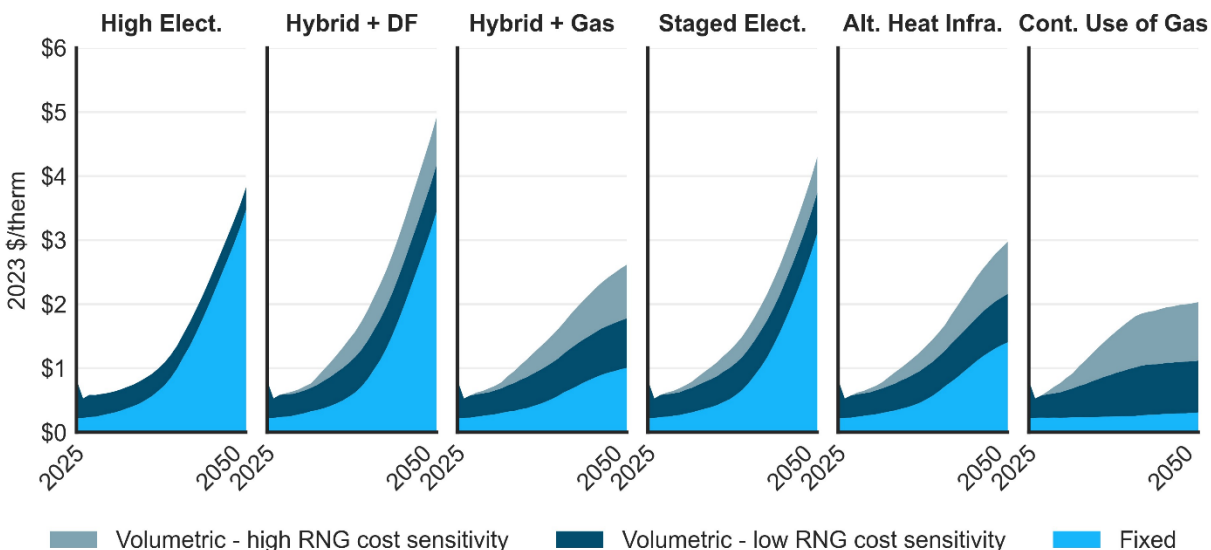
Variable Costs Of Gas

Variable costs of gas, which include commodity costs of gas and the fixed cost of transportation and storage, are passed through to customers and are not included in RIE’s revenue requirement. Fixed transportation and storage costs are assumed to remain the same across scenarios since the infrastructure is required to transport any amount of gas that is still needed on the system. On the other hand, the cost of gas varies significantly across scenarios and depends on the amount of renewable fuels blended into the system.

The commodity rates that customers ultimately pay depend on the scenario’s fixed transportation and storage cost and variable commodity costs, as well as gas throughput. In all scenarios, the commodity costs are expected to rise (see Figure 35). In scenarios with high levels of electrification, transportation and storage rates increase as the costs are spread among fewer customers, leading to higher commodity rates. This assumes that despite reducing gas volumes, RIE would continue to pay long-term contracts for capacity on the system. The extent to which the costs of such contracts can be reduced is uncertain.

In pathways relying on high levels of renewable gas, such as Continued Use of Gas, the volumetric component of commodity rates is forecasted to rise substantially resulting in higher rates, especially after 2040 when levels of renewable gas are expected to increase. However, the impact of declining gas throughput on fixed transportation costs has a more substantial effect on rates than does the cost of renewable gas, resulting in significantly higher rates in the High Electrification, Hybrid with Delivered Fuels Backup, and Staged Electrification pathways. In these scenarios, as the fixed costs of transportation are socialized over fewer units (gas throughput), costs per unit are expected to go up. Similar to the dynamic regarding gas delivery rates, this raises an issue that needs to be addressed in the policy development phase of the docket.

Figure 35. Variable Costs of Gas (commodity costs and transportation & storage costs) under Decarbonization Scenarios

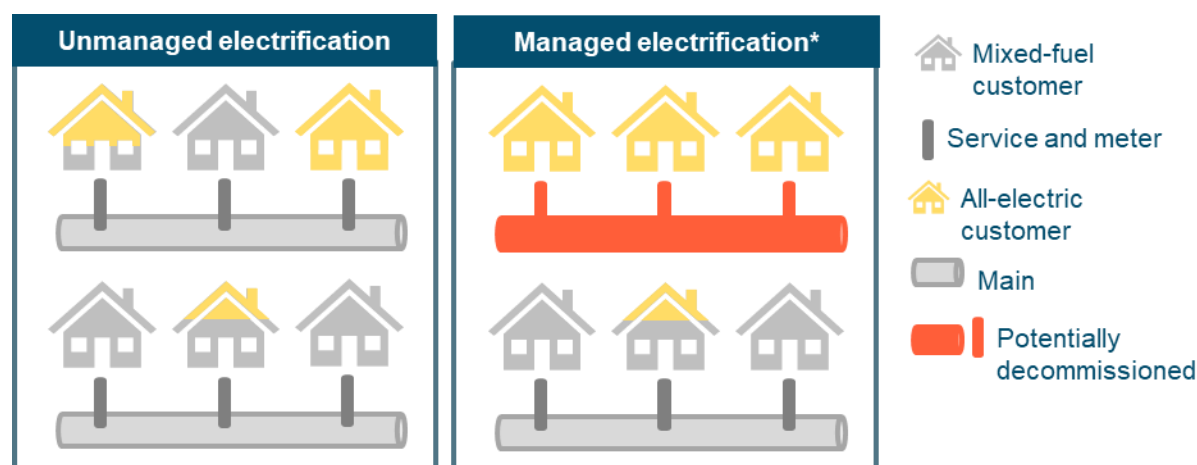


Impacts of a Managed Transition

What is a managed transition?

Although the term “managed transition” is not used consistently in the industry, E3, with input from the TWG, refers to the concept as a set of coordinated, long-term planning strategies deployed in the gas distribution system that align with climate goals and minimize adverse impacts on customers, while safeguarding affordability, safety, and reliability. A managed transition includes targeted deployment of non-GHG emitting heating technologies that minimize or avoid gas system investments, as well as the necessary policy reforms that facilitate these strategies. In the Technical Analysis, E3 uses the term managed transition to indicate the avoidance of gas distribution system infrastructure resulting from targeted electrification projects. With a managed transition approach, RIE would target specific geographic areas for complete building electrification in order to decommission the gas pipeline in that location, avoiding gas pipeline replacement reinvestments (see Figure 36). Although such a strategy requires significant policy and regulatory reform, the Technical Analysis primarily assesses the impacts of the strategy on the gas system and its customers. The question of which types of policies or regulatory strategies are needed to achieve a managed transition, are to be discussed in the Policy Development phase of this Docket. In addition, more detailed engineering questions associated with the technical feasibility of the concept require further study, as outlined in Chapter 6.

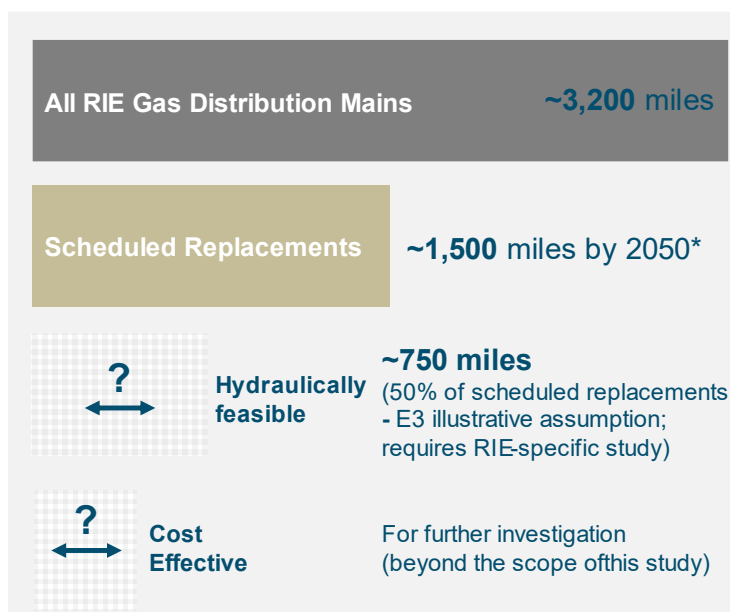
Figure 36. Electrification under an Unmanaged and a Managed Approach



*Also referred to as “targeted/zonal electrification and gas decommissioning”

In the Technical Analysis, E3 conducted sensitivity analysis to explore the potential impact of a managed transition on the gas revenue requirement and, ultimately, delivery rates. Only pipeline that is fully depreciated and scheduled to be replaced will result in avoided capital investment if decommissioned. This means that E3 only considers pipelines that are assumed to reach their end-of-life between now and 2050 as candidates for targeted electrification projects, representing approximately half of all gas distribution mains on the system (see Figure 37). Additionally, to decommission a gas pipeline, it must be considered “hydraulically feasible”, meaning that the gas system maintains the minimum allowable pressures and gas flows and maintains secondary feeds to ensure safe and reliable service to customers that remain on the gas system. In the managed transition sensitivity, E3 assumes that a maximum of 50% of scheduled pipeline replacements can be avoided each year beginning in 2027. This assumption is illustrative; further study is required to understand how much of the system could be feasibly and cost-effectively decommissioned.

Figure 37. Assumptions Regarding The Number Of Distribution System Miles That Can Be Avoided In A Managed Transition. Note: The “hydraulic feasibility” assumptions are illustrative and require further study.



* Based on RIE’s estimation of replacement miles between 2023-2050 (see Figure 10). Represents all cast iron and unprotected steel, plus additional post-2035 plastic mains that are expected to reach end of life.

Managed Transition studies outside of Rhode Island

Although the concept of a managed transition as defined in this study is relatively novel in the United States, several regions have started to investigate the impact and potential benefits of the concept. In December 2023, E3 released a study regarding a benefit-cost analysis of targeted electrification and gas decommissioning in California commissioned by the California Energy Commission.⁸² Evaluating eleven candidate sites in the cities of Oakland, San Leandro, and Hayward, representing 1,500 total utility customers, this study found that all eleven projects would generate lifecycle net benefits associated with targeted decommissioning, even after accounting for the costs of electrification. In Massachusetts, Groundwork Data performed a technical analysis for strategic gas decommissioning and grid resiliency in the City of Holyoke.⁸³ This study demonstrates that a non-pipeline strategy, particularly on low-density streets, can be a cost-effective strategy with significant levels of avoided gas system costs.

Pilot projects are beginning in several jurisdictions to assess the potential benefits of a managed transition for utilities and customers, but these are currently limited in scope and scale. For example, PG&E’s pilot project with East Bay Community Energy in California is assessing how

⁸² E3 (2023). [Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California](#)

⁸³ Groundwork Data (2023). [Equitable Energy Transition Planning in Holyoke Massachusetts - A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency](#).

targeted electrification and gas decommissioning for 105 gas customers can provide gas system savings while meeting the needs of the local community.⁸⁴ Currently in the research phase, the project team has developed a site selection framework and completed a cost-benefit analysis indicating net benefits in specific locations where new gas infrastructure can be avoided. PG&E is moving forward with a pilot program, but the project reflects a small portion of the utility's overall distribution system and customer base. While pilot projects are taking root, there is limited data and examples of the costs and benefits of managed transition projects, and additional pilot projects and analysis are needed to understand the potential to avoid gas system costs.

In estimating an illustrative figure for the potential avoidance of capital replacement costs, E3 draws from several studies that assess the potential for avoided gas system costs, shown in the table below. Not all these studies are based on empirical evidence on hydraulic feasibility or the scale of potential gas system savings.

Table 9. Managed Transition Avoided Capex Assumptions

Study	Managed Transition Assumptions	Source/Notes
MA D.P.U. 20-80 (2021)	All Scenarios: 50% avoided main replacements (illustrative)	Appendix 1: Modeling Methodology ⁸⁵
PG&E Neighborhood Scale Electrification Projects (2024)	~45% hydraulic feasibility of scheduled mains replacements	PG&E Presentation. ⁸⁶ Assumes 30% of projects are feasible by 2030 and 60% by 2045
NY ConEd Long-Term Plan (2023)	Hybrid Electrification: 31% avoided CAPEX Deep Electrification: 64% avoided CAPEX	Gas System Long-Term Plan Update Appendices ⁸⁷ Estimate updated based on revised appendices using weighted average avoided investments from 2026-2043
NY Orange & Rockland Long-Term Plan (2023)	Hybrid Electrification: 16% avoided CAPEX Deep Electrification: 58% avoided CAPEX	Gas System Long-Term Plan Update Appendices ⁸⁸ Estimate updated based on revised appendices using weighted average avoided investments from 2026-2043

⁸⁴ E3 and Gridworks (2023). Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California.

⁸⁵ Massachusetts 20-80 Future of Gas Independent Consultant Report (2021). Appendix 1. [https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20\(Modeling%20Methodology\).pdf](https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20(Modeling%20Methodology).pdf)

⁸⁶ PG&E Presentation during Building Decarbonization Coalition seminar on Jan 25, 2024. <https://buildingdecarb.org/wp-content/uploads/BDC-Presents-Neighborhood-Scale-Slides.pdf>

⁸⁷ ConEd and O&R (2023). Gas System Long-Term Plan Update Appendices. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b10E81C8C-0000-C315-BC56-6BA86F5A265A%7d>

⁸⁸ Ibid.

Impacts of a Managed Transition on Rate Base, Revenue Requirement and Delivery Rates

By avoiding some of the pipeline replacement costs under a managed transition, the rate base (see Figure 38) and the resulting revenue requirement (see Figure 39) is reduced in every pathway except Continued Use of Gas, which must maintain the entire gas system. In the High Electrification and Hybrid with Delivered Fuels Backup pathways, the rate base decreases by approximately 40% by 2050 since these pathways see the most gas customers leave the system, creating the greatest opportunity to electrify customers and decommission pipeline.

Figure 38. Rate Base under an Unmanaged and Managed Transition

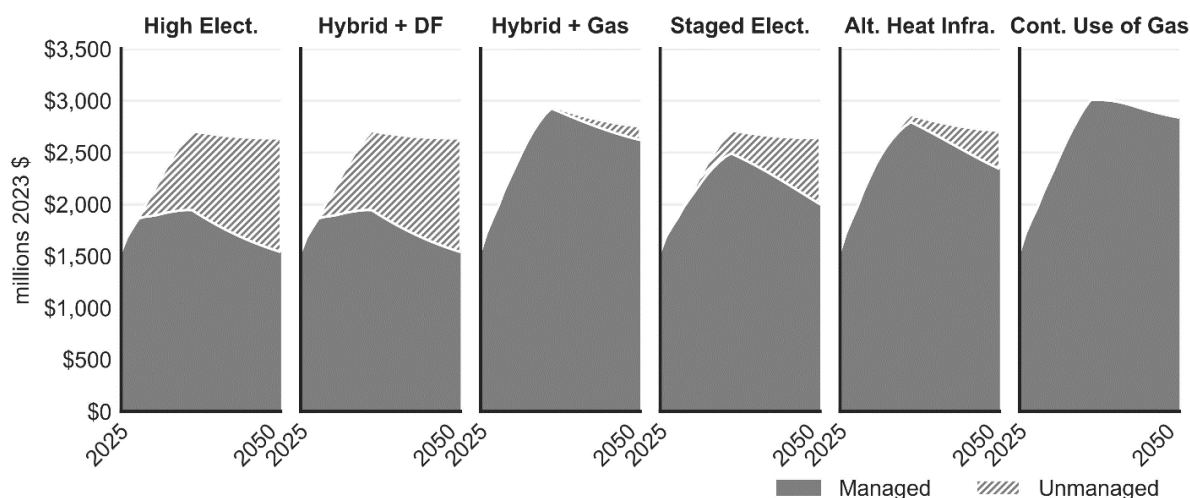
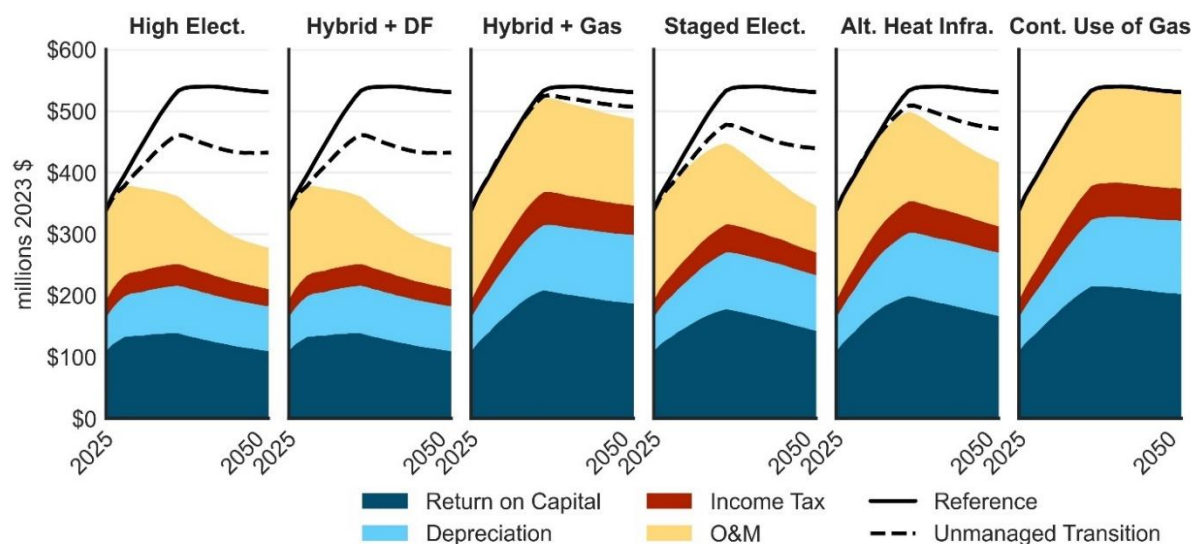


Figure 39. Revenue Requirement under a Managed Transition (note: based on illustrative cost avoidance assumptions)



While the managed transition sensitivity has a sizeable impact on gas rate base and revenue requirement, as well as on statewide total resource costs as described further in Chapter 5, it does not lead to meaningful differences in customer delivery rates, especially for residential customers. The significant decline in gas throughput still causes rates to increase substantially in the long-term. Rates still increase greatly for commercial customers under the managed transition sensitivity, however there is a lesser impact especially for pathways with the highest rates of electrification.

Figure 40. Residential Delivery Rates under Unmanaged and Managed Transitions

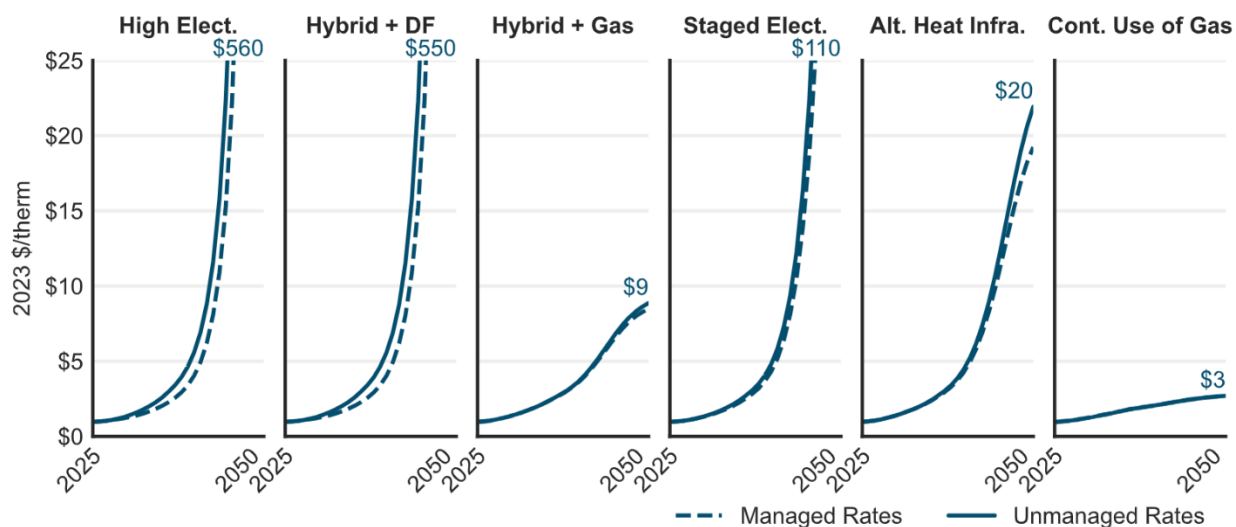
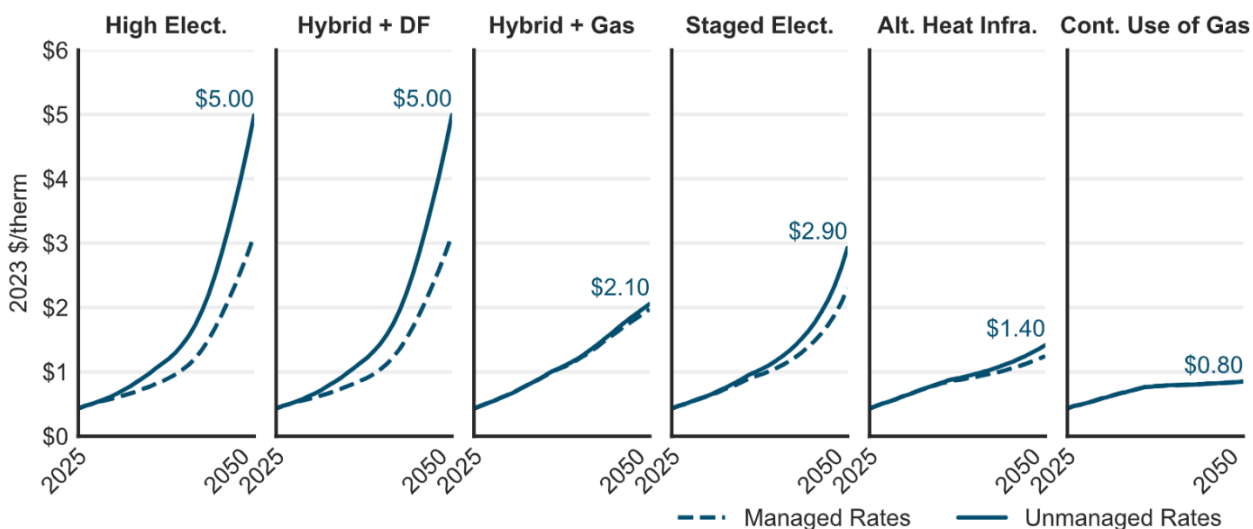


Figure 41. Large C&I Delivery Rates under Unmanaged and Managed Transition

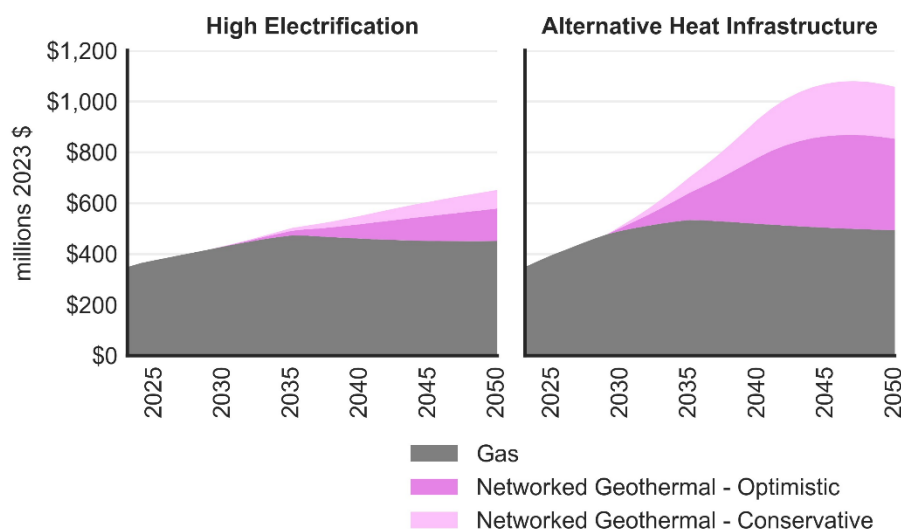


Networked Geothermal Systems

Two decarbonization scenarios, High Electrification and Alternative Heat Infrastructure, include the transition of some of the gas customer base to networked geothermal systems. E3 assumes that the

costs of installing networked geothermal infrastructure (not including appliances on customer premises) will be financed and recovered by a utility-type entity under cost-of-service regulation similar to the current gas system cost recovery. E3 estimated the revenue requirement based on the investment required for networked geothermal and added this to the gas revenue requirement in both the High Electrification and Alternative Heat Infrastructure scenarios (see Figure 42). Note that the costs of the gas system in this figure are provided for reference and comparison purposes only, not implying that networked geothermal systems would need to be installed by RIE.

Figure 42. Networked Geothermal Revenue Requirement Addition to Gas Revenue Requirement (gas system costs shown without managed transition assumptions)



The concept of networked geothermal systems as applied in the Technical Analysis is relatively novel, and the costs of installing these systems are uncertain. More research is required to understand the feasibility and cost-effectiveness of the systems, as further described in Chapter 6.

About Networked Geothermal Systems

Similar to the concept described by HEET in its Geothermal Networks Feasibility Study (2019), E3 refers to a networked geothermal system as an underground connection of pipes and pumps that transfer heat and cooling from the ground to buildings in a shared loop network.⁸⁹ A networked geothermal system moves heat in the ground and excess heat from other buildings to a home or business that needs heating, resulting in an efficient heating system. In the Technical Analysis, E3 assumes that networked geothermal systems achieve a constant coefficient of performance (COP) of 6, compared to between 0.90 – 1 for gas furnaces and approximately 3 for ASHPs. A

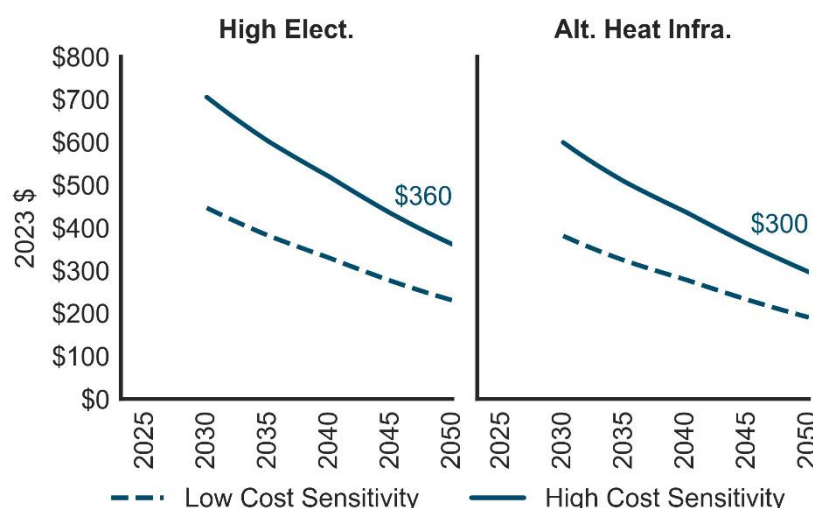
⁸⁹ HEET and BuroHappold. Geothermal Networks 2019 Feasibility Study (2019). https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf

networked geothermal system additionally transfers heat out of buildings to provide cooling, making it valuable in winter and summer seasons.

The transfer of heat across buildings in the shared loop means that it is beneficial to connect buildings with diverse heating loads. For example, grocery stores have large cooling loads, whereas homes have smaller heating and cooling loads that track the seasons. Grouping these buildings in a single system can enable these loads to be balanced across the network.

In this report, E3 assumes that the revenue requirement for networked geothermal will be recovered by networked geothermal customers, resulting in a monthly networked geothermal connection charge (see Figure 43). The connection charge begins in 2030 when the networked geothermal system is assumed to be installed and declines over time as more customers are added to the system. However, it is important to note that the means to finance and recover costs for a networked geothermal system may be designed in multiple ways. Such alternative options are not reflected in the costs on Figure 43.

Figure 43. Residential Monthly Networked Geothermal Connection Charge

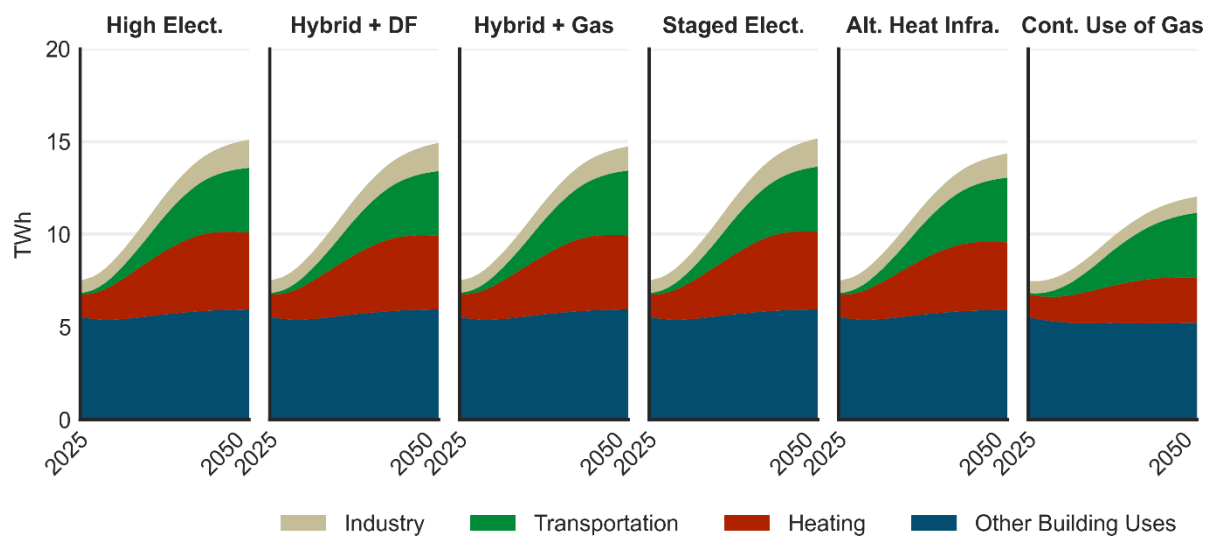


Impact on the Electric System

Load Growth And Electric System Peak Impacts

The electric sector is expected to serve nearly double the annual system load by 2050, regardless of scenario. Shown in Figure 44, the primary drivers of annual load growth across all mitigation scenarios are transportation and heating electrification. LDVs make up the bulk of transportation loads and are a result of Rhode Island successfully meeting ACCII targets.

Figure 44. Annual Load Growth across Decarbonization Scenarios

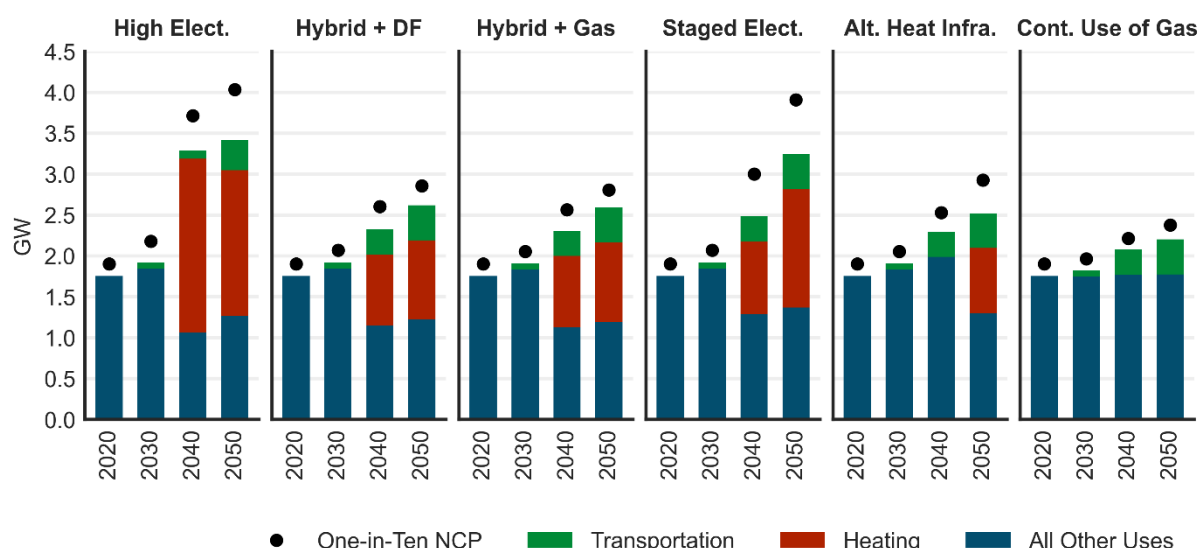


The differences in annual load growth between mitigation scenarios is primarily driven by the level and kind of heating electrification. Annual load growth is the slowest in the Continued Use of Gas scenario because of lower general levels of heating electrification. The Hybrid and Alternative Heat Infrastructure scenarios rely on high penetrations of hybrid heating or highly efficient whole-building heating (through networked geothermal systems), resulting in moderate levels of heating load growth. Finally, the High and Staged Electrification scenarios rely on high penetrations of whole-building ASHPs, leading to the highest heating load growth by 2050.

Electric-sector reliability is driven by its ability to serve large electric demands under extreme weather conditions. These peak loads were estimated using weather data across the 40 weather years from 1979 to 2018. Two types of peak loads were estimated in this study:

- Median, or 50/50, coincident peaks.** Median peaks are considered the “average” peak load. These peak loads result when high loads across multiple sectors coincide to produce high, system-wide demand. Note that, in general, the coincident peak does not occur simultaneously with any one sector’s peak. This peak, paired with a planning reserve margin, is important to estimate generator-level reliability.
- One-in-ten, or 90/10, noncoincident peaks.** One-in-ten peaks are more extreme than 90% of all peaks calculated using the 1979-2018 weather year data. Unlike the above coincident peaks, the one-in-ten noncoincident peaks were calculated as the sum of the per-sector peak loads. This peak is important to ensure appropriate transmission and distribution sizing.

Figure 45. Post-Flexibility Median (50/50) Coincident Peak Loads By Contribution And 1-In-10 (90/10) Noncoincident Peak Loads. Heating electrification contributions to the peak indicate a transition to winter peaking.⁹⁰



Peak loads are often driven by weather, with summer peaks today largely driven by air conditioning loads. Electrification of heating leads to an increase in winter peaks as space heating needs increase with colder temperatures. The amount of heating electrification and the type of technology underlying heating electrification drive the extent to which winter peaks increase, and determine whether Rhode Island’s electric system remains “summer peaking”, or transitions to “winter peaking”. Figure 45 shows that nearly all scenarios, except Continued of Use of Gas, result in a significant contribution of heating electrification to the annual system peak in the state starting in the 2030s or 2040s, indicated by the “heating” category on the figure. This demonstrates that in those scenarios, Rhode Island is expected to transition to a winter peaking system, where the winter peak is driven by the need for electricity to satisfy space heating demands.

Those scenarios (High Electrification and Staged Electrification) relying on high penetrations of whole-building ASHPs have the highest peak load growth, with median peaks nearly doubling by 2050. This effect results from the fact that the efficiency of ASHPs decreases as the outdoor air temperature drops, leading to relatively significant levels of electric system peak impacts in winter. In contrast, scenarios with hybrid heating or very efficient whole-building heating have slower peak growth since those scenarios avoid the impact of cold winter peaks. In the scenarios with high levels of hybrid heating (Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup), winter peaks are avoided through gas and/or delivered fuel backup systems in cold hours of the year. In the Alternative Heat Infrastructure scenario, winter peaks are avoided through both the use of hybrid heat pumps and the use of networked geothermal systems that show significant, weather-independent

⁹⁰ The peak heating contribution in the High Electrification scenario decreases from 2040 to 2050 as the median peak load shifts from cold, low LDV-charging morning hours to slightly warmer, high LDV-charging evening hours.

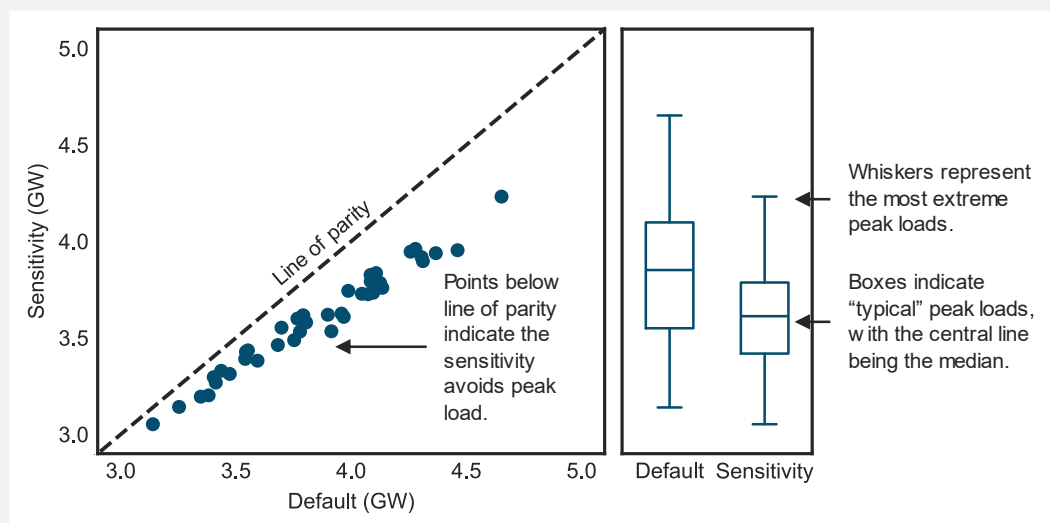
efficiency benefits. These scenarios also demonstrate that hybrid and efficient heating can mitigate peak load impacts under more extreme weather conditions, as shown by the 1-in-10 noncoincident peaks.

Load flexibility is an important component in mitigating peak load growth. Load flexibility can take the form of an electric vehicle delaying charging until after an evening peak or buildings pre-heating or cooling prior to an extreme weather event. E3 assumed that 50% of home light-duty vehicle charging, 25% of water heating, and 4% of space heating loads could be avoided during the identified peak load hour. While not shown in Figure 45, load flexibility reduced both the median coincident and the one-in-ten noncoincident peaks between 350-450 MW across all decarbonization scenarios.

Impact of higher efficiency heat pumps on peak loads

E3 evaluated the effect of high heat pump efficiency for the High Electrification scenario. In this sensitivity, E3 substituted modeled whole-home heat pumps, which were sized to meet the 99th percentile of heating demands and supplemented by electric resistance, with high efficiency heat pumps with no electric resistance backup. The effect of these heat pumps were then evaluated by calculating the system peaks across weather years 1979-2018 and comparing them to those peaks from the High Electrification scenario, the results of which are contained in Figure 46. The results show that substituting high efficiency heat pumps can reduce median peak loads by 250-300 MW up to 500 MW under the most extreme conditions.

Figure 46. High Electrification 2050 System Peak Loads Under Default And High Efficiency Heat Pump Sensitivity Assumptions For Weather Years 1979-2018.



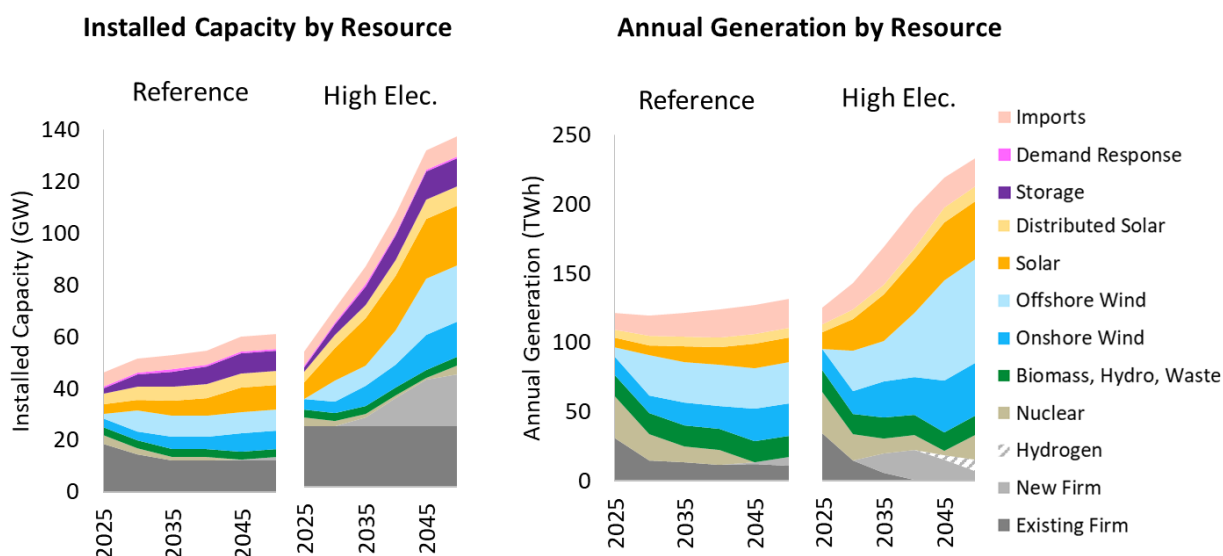
Note: Each point represents peak loads for the sensitivity and default for a given weather year. Box-and-whisker plots summarize peak load distribution under both sets of assumptions.⁹¹

⁹¹ Results on the line of parity would indicate that the sensitivity produces peak loads consistent with the default assumptions.

Capacity & Generation Needs On The ISO New England System

To serve the increasing electric demand across all scenarios, the New England electric system is expected to see transformational changes in generation and capacity. E3 modeled the entire ISO New England for generation capacity expansion considering the current clean and renewable energy policies across all states in New England, including the Rhode Island's 100% Renewable Energy Standard by 2033. As shown in Figure 47, renewables will become a major source of electricity across all scenarios in New England, including in the reference scenario. In the High Electrification scenario, substantial increase in renewables lead to nearly 3x higher installed capacity needs by 2050, dominated by wind and solar. The need for firm (gas) capacity drops in the reference scenario due to relatively flat load profiles, while new firm capacity is required in the other scenarios to reliably serve increasing demand from electrification. The ISO New England-wide cost of generation was scaled down to Rhode Island in each scenario using its share of annual electric demand in the entire ISO.

Figure 47. Installed Capacity and Generation Mix across ISO New England (GW)



Cost Of Electric Service In Rhode Island

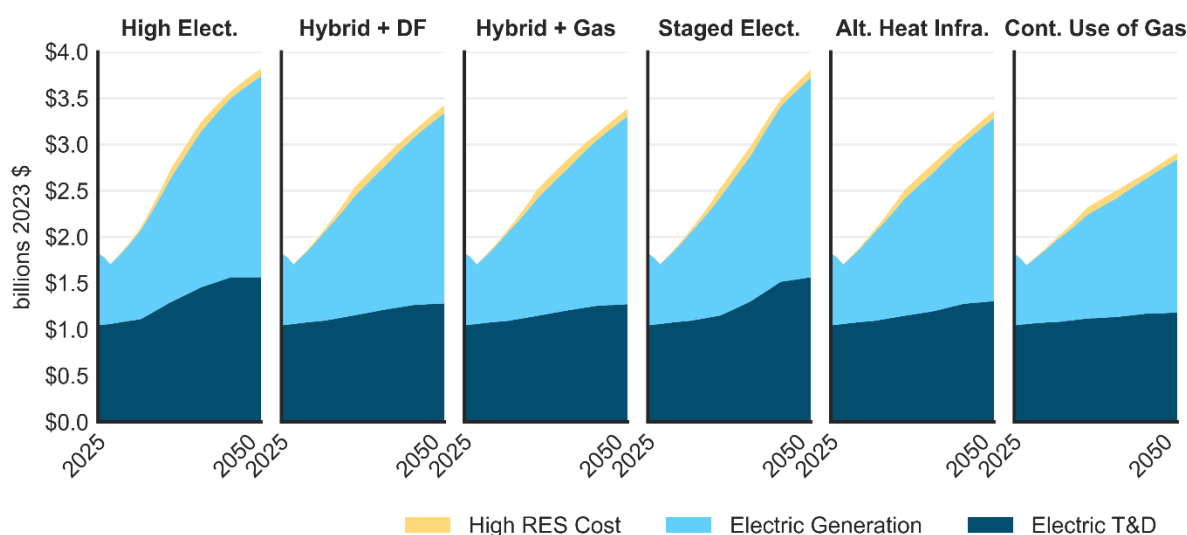
Total cost of electric service in Rhode Island approximately doubles by 2050 due to increased renewable generation and capacity needs (Figure 48). This is driven by higher electric demand, which increases both generation and transmission and distribution (T&D) infrastructure costs to serve the demand, and higher cost of electric generation to meet the 100% Renewable Energy Standard.

Achieving 100% RES by 2033 increases the cost of generation in Rhode Island over the average cost in ISO New England. On average, approximately 60% of the total generation will be from renewable sources across the entire ISO New England by 2033 if all states achieve their renewable and clean energy targets. In this study, it is assumed that Rhode Island needs to pay a premium to meet the 100% RES in addition to the average renewable generation mix achieved in ISO New England. This premium will be paid via purchases of RECs, represented in two bounding scenarios with \$31/MWh

on the low end and \$51/MWh on the high end. Figure 48 shows that the \$51/MWh high-end RES sensitivity would add an additional \$64-87 million per year in Rhode Island across all scenarios compared to the low-end sensitivity, relative to the average cost of generation in ISO New England.

Average cost of generation increases from \$104/MWh in 2023 to approximately \$150/MWh in 2050 across all scenarios, driven by increasing capacity need from electrification and higher penetration of renewables. Increasing cost of building renewable resources in recent years further contributes to the cost increase from 2023 to 2050. For example, recent market prices show that average cost of new solar installations increased by at least 20% from 2021, while offshore wind prices increased by at least 33% from 2020.⁹²

Figure 48. Current and 2050 Total Cost of Electric Service (2023\$ Billion)



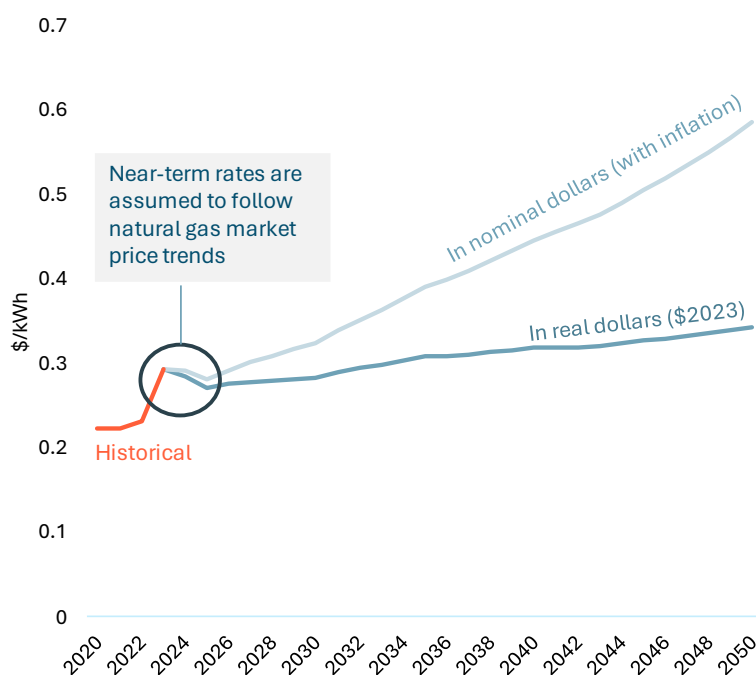
Scenarios with higher levels of electric heat pump adoption, such as the High Electrification scenario and the Staged Electrification scenario, see higher levels of T&D spending in the long term due to heat pump capacity needs. The Continued Use of Gas scenario, on the contrary, shows lowest cost of generation and T&D spendings due to lower levels of electrification.

Impacts on electric rates

Rhode Island experienced a steep increase in 2022-2023 electric rates driven by higher natural gas prices, mostly resulting from natural gas supply chain constraints. As shown in Figure 49, in the near-term, E3 assumes that the residential rate follows natural gas market price trends, leading to a reduction in rates in the next two or three years. Beyond 2025 in all scenarios, the costs of electricity are expected to remain higher than the rate of inflation. With electric load increasing over time, rate impacts are mitigated as costs are shared over more load. However, in real dollars (excluding impacts of inflation), rates still increase by 17% between 2023-2050 driven by higher costs for renewable generation, transmission and distribution.

⁹² Renewable resource costs are based on the 2023 NREL Annual Technology Baseline and recent market trend, including federal tax credit impacts from the Inflation Reduction Act of 2022.

Figure 49. Rhode Island Historical and Projected Residential Rates in High Electrification Scenario



Across all scenarios, electric rate increases are mitigated through load growth to some extent. When spreading the total cost of service over the total load, cost of service increases are largely offset by increased loads, especially for scenarios with high load factors. As shown in Figure 50, in the scenarios with higher levels of electric heat pump adoptions (i.e. High Electrification scenario and Staged Electrification scenario), higher heating load from all-electric heat pumps requires more capacity resources per MWh increase in load to ensure system reliability, thus driving up rates. In scenarios where hybrid heat pumps take up a larger share (i.e. Hybrid with Delivered Fuels Backup scenario and Hybrid with Gas Backup scenario), alleviated peak impacts reduce the need for capacity resources, increasing scenario load factors and therefore lowering the cost per MWh to serve electrification load. The Continued Use of Gas scenario sees relatively high rates due to lower levels of load increase with similar Renewable Energy Standard requirements.

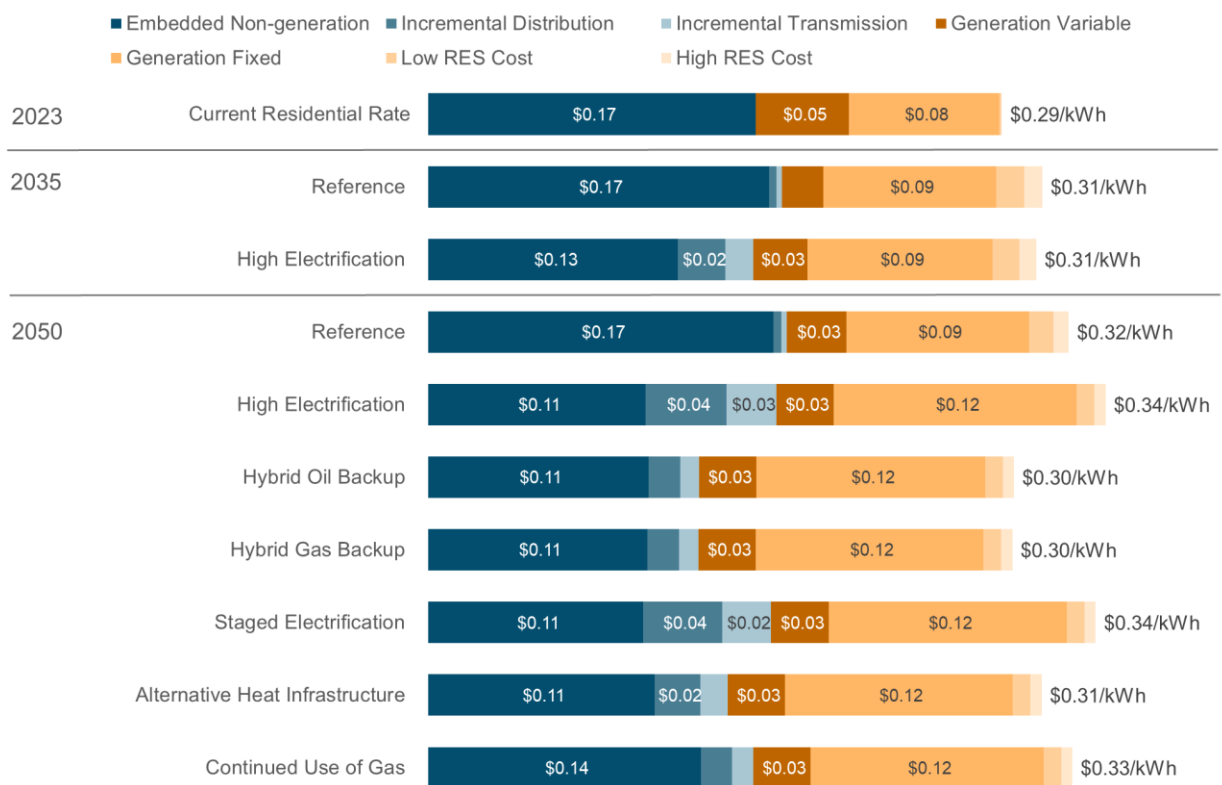
Electricity rates modeled in the Technical Analysis

In the Technical Analysis, E3 modeled average electricity rates through a statewide approach that identifies total electric system costs (including generation, transmission, and distribution costs) and total electric load. At the highest level, this means that the total annual costs of service in Rhode Island are allocated to different customer classes (residential, commercial and industrial) and divided by the annual electric load from those classes. This means that the electricity rates depicted on Figure 49, Figure 50 and as used in the customer bill analysis in Chapter 5 show systemwide average rates or “unit costs” by customer class. These rates are not reflective of specific rate design structures or rate components that individual customers may see on their bill. For example, customers participating in net metering would see a net reduction in electricity rates

and bills that is not reflected in this average unit cost metric. In addition, the rate components depicted on Figure 50 represent average generation, distribution and transmission costs associated with decarbonization and do not necessarily reflect real-world wholesale market dynamics, nor do they reflect the impact of potential long-term procurement contracts that may influence customer rates.

For residential electric rates, Figure 50 shows that achieving RES increases rates by ¢1.3-2.3/kWh by 2035. Unit costs of RES, by 2050, are lower in mitigation scenarios due to load growth (¢0.9-1.5/kWh). The implications of electric rate increases across scenarios and the impact on customer affordability are further discussed in Chapter 5.

Figure 50. Residential Electric Rates by Scenario and impact of Renewable Energy Standard (RES)



5. Decarbonization Pathways – Assessment and Implications

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges. This chapter describes key implications of scenarios across a set of evaluation criteria, as introduced in Chapter 3. The evaluation criteria and associated metrics were defined together with the Stakeholder Committee and TWG.

Table 10 provides an overview of key metrics assessed across multiple evaluation criteria that demonstrate differences and commonalities across scenarios. The evaluation criteria are discussed in detail in the section below. Additionally, not shown in the table, E3 provides qualitative considerations with regard to workforce impacts in this chapter.

Table 10. Assessment of Evaluation Criteria

Criteria	Representative Metric		High Electrification	Hybrid w. DF Backup	Hybrid w. Gas Backup	Staged Electrification	Alternative Heat Infra	Cont. Use of Gas
Total Resource Costs	Net Present Value between 2023-2050, incremental to reference		\$18-22 billion	\$15-21 billion	\$14-19 billion	\$15-20 billion	\$17-24 billion	\$16-26 billion
	Illustrative NPV savings if up to 50% of gas CAPEX can be avoided ⁹³		-\$1.7 billion	-\$1.7 billion	-\$0.1 billion	-\$0.7 billion	-\$0.4 billion	-\$0.0 billion
Customer choice	Annual no. of targeted electrification customers (2035)	Un-managed	0	0	0	0	0	0
		Managed	~3,000	~3,000	0	~1,200	~700	0
Long-term affordability	2050 monthly total cost of ownership (TCO) for migrating customer		~\$700	~\$700	~\$700	~\$700	~\$800	~\$700
	2050 monthly TCO for non-migrating customer		> \$3,000	> \$3,000	~\$1,500	> \$3,000	> \$3,000	~\$700
	TCO “inflection year” for residential gas vs. all-electric customer ⁹⁴		2036	2037	2037	2036	2036	2046
Air Quality Impacts	Change in statewide fuel combustion between 2020-2050 (%)		-85%	-82%	-81%	-85%	-82%	-65%

⁹³ Represents reduction in NPV if 50% of CAPEX can be avoided through managed transition, relative to the above row

⁹⁴ “Inflection year” is defined as the point in time where the TCO for an all-electric heating customer is lower than for a gas heating customer, under the current regulatory framework.

Reliance regional fuel supply	Total annual volume of renewable fuel required by 2050 (Tbtu)	11	15	15	11	13	33
Technology Readiness⁹⁵	Likely range of Technology Readiness Levels required to achieve AoC	8-10	7-10	7-10	8-10	6-10	6-11
Electric System Expansion	Total increase in distribution system capacity by 2035 (GW)	1.2	0.5	0.4	0.5	0.4	0.2

Total Resource Costs

Total resource costs by pathway are determined based on the incremental costs of a scenario compared to the reference scenario. This metric provides an understanding of the costs of additional efforts required for the state of Rhode Island to comply with the Act on Climate, on top of the efforts already underway through existing policies and trends. Total resource costs include all energy-related decarbonization costs, including demand-side capital (costs to install appliances, purchase vehicles, etc.), gas infrastructure, electric infrastructure, geothermal infrastructure, and the cost of fuels. The social costs of carbon and other societal benefits, such as health impacts, are not included in this evaluation.

Due to the uncertain nature of the costs associated with the transition over a time horizon of 30 years, the analysis considers a range of cost sensitivities for key input parameters, as described in Chapter 3. The key findings related to total resource costs are therefore presented as ranges of costs. More detail on the costing approach is provided in Appendix A.4.

Cumulative Resource Costs across Scenarios

Across scenarios, the cumulative incremental total resource costs, expressed in NPV between 2023-2050, vary from \$14.0B to \$17.6B with low-bound cost input parameters and \$19.0B to \$25.9B with high-bound cost input parameters. These figures exclude the impact of a managed transition (see textbox below), or the impact of potentially higher efficiency heat pumps that were analyzed as separate sensitivities. Driven by uncertainty around the future cost of renewable fuels, the high-bound cost parameters show higher levels of variation across scenarios. Scenarios with high reliance on renewable fuels, such as the Continued use of Gas scenario, are therefore at higher risk of exposure to more costly renewable fuels.

Across both low- and high-bound cost assumptions, scenarios that leverage hybrid heating technologies, including Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup and Staged Electrification show lower overall costs. These scenarios avoid electric system investments while also reducing dependence on fuels compared to scenarios that rely more heavily on fuels as the

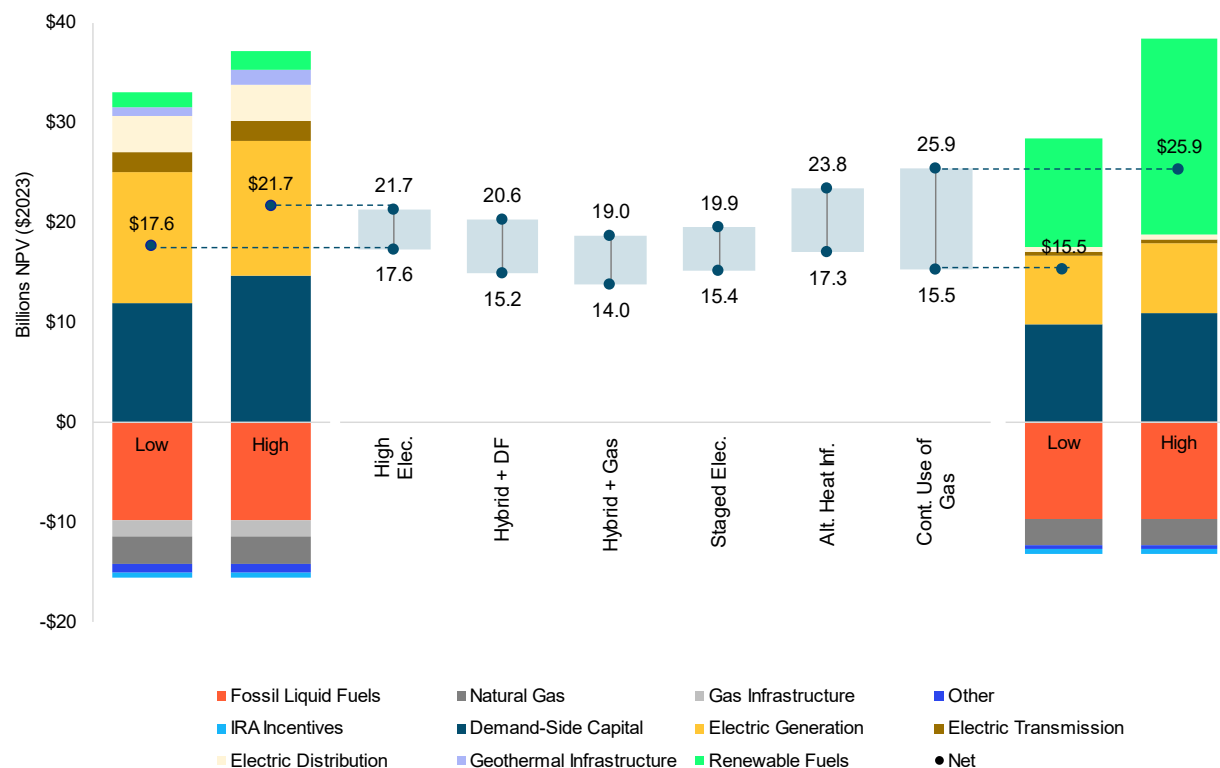
⁹⁵ E3 uses the Technology Readiness Level (TRL) scale defined by the International Energy Agency (IEA), where 1 refers to the lowest level of technology commercialization and 11 to the highest level of technology commercialization.

primary heating solution, such as Continued Use of Gas. However, scenarios that leverage hybrid heating solutions show higher levels of risk associated with the cost of renewable fuels compared to scenarios that rely more heavily on electrification, such as the High Electrification scenario.

Figure 51 shows the range of net present value total incremental resource costs across scenarios, with a breakdown by component for the High Electrification and Continued Use of Gas scenarios. This figure shows the total statewide costs of decarbonization measures across scenarios relative to the reference scenario, accounting for both savings and costs of fuels, demand-side capital, electric system, gas system and networked geothermal system costs, incorporating potential savings from Inflation Reduction Act (IRA) incentives. All resource costs are shown on a net present value basis, representing the cumulative incremental costs of the transition between 2023-2050, discounted with a factor of 1%.

Figure 51 demonstrates that although total resource costs fall in a similar range across scenarios, the breakdown of costs varies widely: In the High Electrification scenario for example, the largest cost components are associated with the buildout of electric system infrastructure; in the Continued Use of Gas scenario, the largest cost component represent the costs of renewable fuels. In addition, the High Electrification scenario shows a cost reduction related to gas infrastructure as a result of lower customer connection costs associated with new gas infrastructure compared to a reference scenario. Both scenarios show similar levels of costs associated with demand-side capital, as well as similar levels of cost savings due to the reduction of fossil fuel use.

Figure 51. Range of Net Present Value Total Resource Cost by Scenario using Low and High Cost Input Parameters – breakdown of Components for High Electrification and Continued Use of Gas



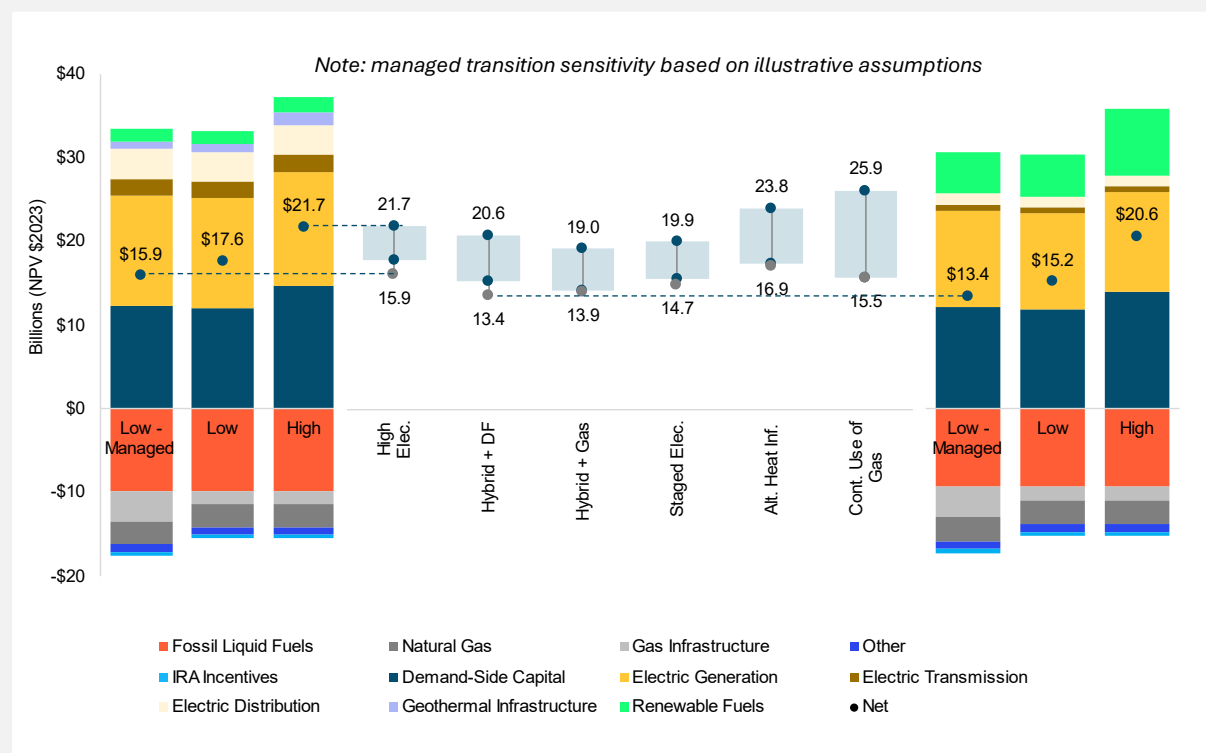
Impact of a managed transition on total resource costs

In scenarios that are able to avoid long-term gas infrastructure, a managed transition can further reduce total resource costs. For illustrative purposes E3 assumed that a maximum of 50% of annual gas capital expenditures can be avoided in scenarios that allow for targeted electrification, which reduces annual gas revenue requirement as described in Chapter 4. Based on this illustrative assumption, total resource costs decline by approximately \$1.7 billion in both the High Electrification and Hybrid with Delivered Fuels scenarios. The Staged Electrification scenario sees a reduction in total resource costs of \$0.7 billion, as this scenario has less opportunity to avoid gas infrastructure in the near term when most of the leak-prone pipe replacements are due.

The total resource cost reductions assessed in this analysis incorporate both the savings in gas infrastructure resulting from avoided capital expenditures, as well as increased costs related to the early retirement of heating equipment in customer homes. The latter category is relatively small compared to the savings of infrastructure, assuming that in an *unmanaged transition*, the same customers would have electrified their heating equipment later in time. The costs associated with early retirement therefore only reflect the costs of adopting electric heating equipment a few years earlier in time. Regardless, since electric heating equipment is significantly more expensive than gas heating equipment, a managed transition still includes challenges associated with the upfront cost of customer equipment. In addition, a cost-benefit assessment

incorporating both gas infrastructure avoidance and customer heating equipment will vary on an individual street level, as this assessment is highly dependent on the density of streets.

Figure 52. Range of Net Present Value Total Resource Cost by Scenario under a Managed Transition – breakdown of Components for High Electrification and Hybrid with Delivered Fuels.



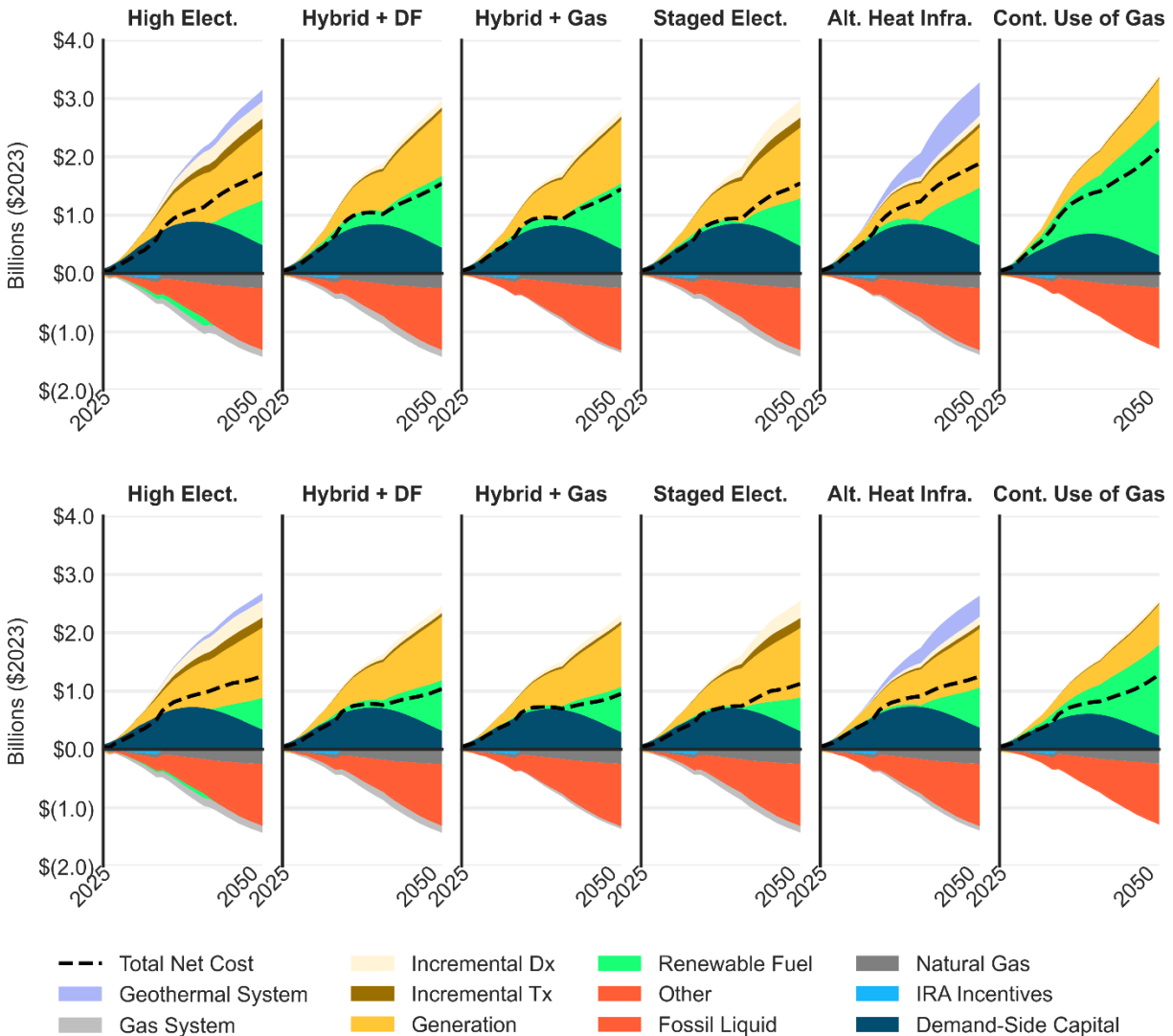
The extent to which total resource costs can be reduced as a result of a managed gas transition highly depends on the extent to which near-term capital expenditures on the gas system can be avoided. As E3 primarily relied on illustrative assumptions for this analysis, much more research is needed to better understand the opportunity associated with avoiding gas infrastructure.

As shown in Figure 53, the annual costs of the transition increase over time, with the majority of annual costs accounted for beyond the 2030s. In the near term, total costs are weighed more heavily towards demand-side capital accounting for the costs of heat pumps and electric vehicles, shifting to a combination of demand-side capital, electric system, and renewable fuels costs in the long term. This is due to two primary reasons:

- + The use of renewable fuels increases only later in time to comply with Rhode Island's increasingly stringent emissions targets. With demand for renewable fuels increasing, the costs of renewable fuels are expected to increase and more expensive resources are expected to be required to meet growing demand.
- + Incremental costs of the electric system are expected to be lower in the near term as the cost of renewable generation make up a lower portion of total electric system costs and more headroom is available on the system to interconnect distributed generation. As the RES

becomes more stringent and the available headroom on the system declines, the costs of generation, transmission and distribution are expected to go up.

Figure 53. Annual Incremental Costs. Top: high-bound cost input assumptions. Bottom: low-bound cost input assumptions.



Impact of avoidance of hybrid backup installation costs on total resource costs

In the Technical Analysis, E3 assumes that customers that convert to hybrid electrification bear the costs of both all-electric appliances, such as ASHPs, as well as the costs of a backup system (i.e. gas or delivered fuel furnace or boiler). Although most customers have existing furnaces or boilers, it is reasonable to assume that in a long-term transition, these furnaces or boilers need to be replaced at end-of-life similar to other appliances.

However, in some cases customers may be able to benefit from existing furnaces or boilers with minimal additional investments, for example through burner-tip adjustments for conversion to propane use. In these cases, it is assumed that a customer would transition to all-electric appliances later in time as their furnace or boiler reaches end of life, or that a customer would significantly extend the lifetime of their backup system. E3 explored the potential total resource cost savings that can be achieved if the cost of hybrid backup systems can be avoided. This sensitivity analysis found a total cumulative incremental saving \$1.1B for the Staged Electrification scenario. It is reasonable to assume that this benefit would mostly be applicable to the Staged Electrification scenario that transitions to all-electric heating in the long term, but a similar benefit may be seen in the Hybrid with Delivered Fuels backup scenario or Hybrid with Gas Backup scenarios for customers that are able to retain existing backup systems without replacement for additional years of useful life, before replacing the backup system or transitioning to a fully electric heating system.

Cost Uncertainty Analysis

As noted in Chapter 3, E3 accounted for uncertainties in incremental resource costs through sensitivity analysis using both low-bound and high-bound cost parameters for key input assumptions. Using these sensitivity parameters, E3 performed a cost uncertainty assessment based on the theory of “regret analysis.” Regret analysis helps inform whether a finding of lower costs for particular decarbonization measures or scenarios is robust to various sensitivities.⁹⁶ “Regret” is defined as the extra cost of a given scenario for each sensitivity above the lowest cost scenario within that sensitivity.

The tables below shows two variations of costs across scenarios. Table 11 (top) shows the incremental total resource costs of scenarios relative to the reference case isolated by sensitivity parameter. For example, the “high heat pump costs” column represents the total resource costs in a worldview where *only* the costs of heat pumps represent conservative input parameters, holding all other parameters constant at low-bound cost input parameters. Comparing the costs in this column to the “low cost sensitivity” column on the left allows us to view the impact of potential higher costs of heat pumps in isolation, providing insight into the risks associated with higher costs of heat pumps. Table 12 (bottom) shows the additional costs of a given scenario above the lowest cost scenario within each sensitivity column. A regret of zero indicates that the scenario was the lowest cost scenario within that sensitivity column. For example, in the “high heat pump costs” sensitivity, all scenario costs are shown as incremental to the Hybrid with Gas Backup scenario as that scenario shows the lowest costs within that column.

⁹⁶ Based on Decision Theory: Peterson M. An Introduction to Decision Theory. Cambridge University Press, 2013

Table 11. Incremental Total Resource Costs By Scenario, Isolated By Sensitivity Parameter (in \$2023 billion cumulative NPV costs).

<i>Sensitivity → (in \$2023 billion)</i>	Low cost sensitivity	Managed Transition	High heat pump costs	High REC costs	High RNG costs	High networked geo costs	High cost sensitivity
High Electrification	\$17.7	\$15.9	\$20.4	\$18.1	\$18.0	\$18.3	\$21.7
Staged Electrification	\$15.4	\$14.7	\$17.9	\$15.8	\$17.0	\$15.4	\$19.9
Alt. Heat Infrastructure	\$17.4	\$17.0	\$19.3	\$17.7	\$19.5	\$19.6	\$24.0
Continued Use of Gas	\$15.5	\$15.5	\$16.8	\$15.6	\$24.6	\$15.5	\$25.9
Hybrid with Gas Backup	\$14.0	\$13.9	\$16.2	\$14.3	\$16.6	\$14.0	\$19.0
Hybrid with DF Backup	\$15.2	\$13.4	\$17.4	\$15.5	\$18.1	\$15.2	\$20.6

Table 12. Sensitivity Analysis Across Scenarios And Sensitivities (in \$2023 billion cumulative NPV costs). Costs are shown as incremental to the lowest cost scenario per sensitivity.

<i>Sensitivity → (in \$2023 billion)</i>	Low cost sensitivity	Managed Transition	High heat pump costs	High REC costs	High RNG costs	High networked geo costs	High cost sensitivity
High Electrification	\$3.7	\$2.5	\$4.3	\$3.7	\$1.5	\$4.2	\$2.7
Staged Electrification	\$1.4	\$1.3	\$1.8	\$1.4	\$0.4	\$1.4	\$0.8
Alt. Heat Infrastructure	\$3.4	\$3.6	\$3.2	\$3.4	\$2.9	\$5.6	\$4.9
Continued Use of Gas	\$1.5	\$2.1	\$0.6	\$1.3	\$8.0	\$1.5	\$6.8
Hybrid with Gas Backup	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Hybrid with DF Backup	\$1.2	\$0.0	\$1.2	\$1.2	\$1.6	\$1.2	\$1.6

The sensitivity analysis shows that the costs of renewable fuels and the costs of networked geothermal systems demonstrate the highest levels of incremental costs. Scenarios that rely more heavily on renewable fuels or networked geothermal systems therefore imply higher levels of risk than scenarios with lower reliance on these components. The scenarios that rely more heavily on hybrid solutions, such as Hybrid with Gas Backup, Hybrid with Delivered Fuels Backup, and Staged Electrification demonstrate lowest levels of cost uncertainty across all sensitivity parameters (indicated by relatively low levels of regret across rows). It is important to note that this analysis only considers uncertainty across the parameters selected for sensitivity analysis, and is dependent on the value of input specific input assumptions, as detailed in Appendix B.

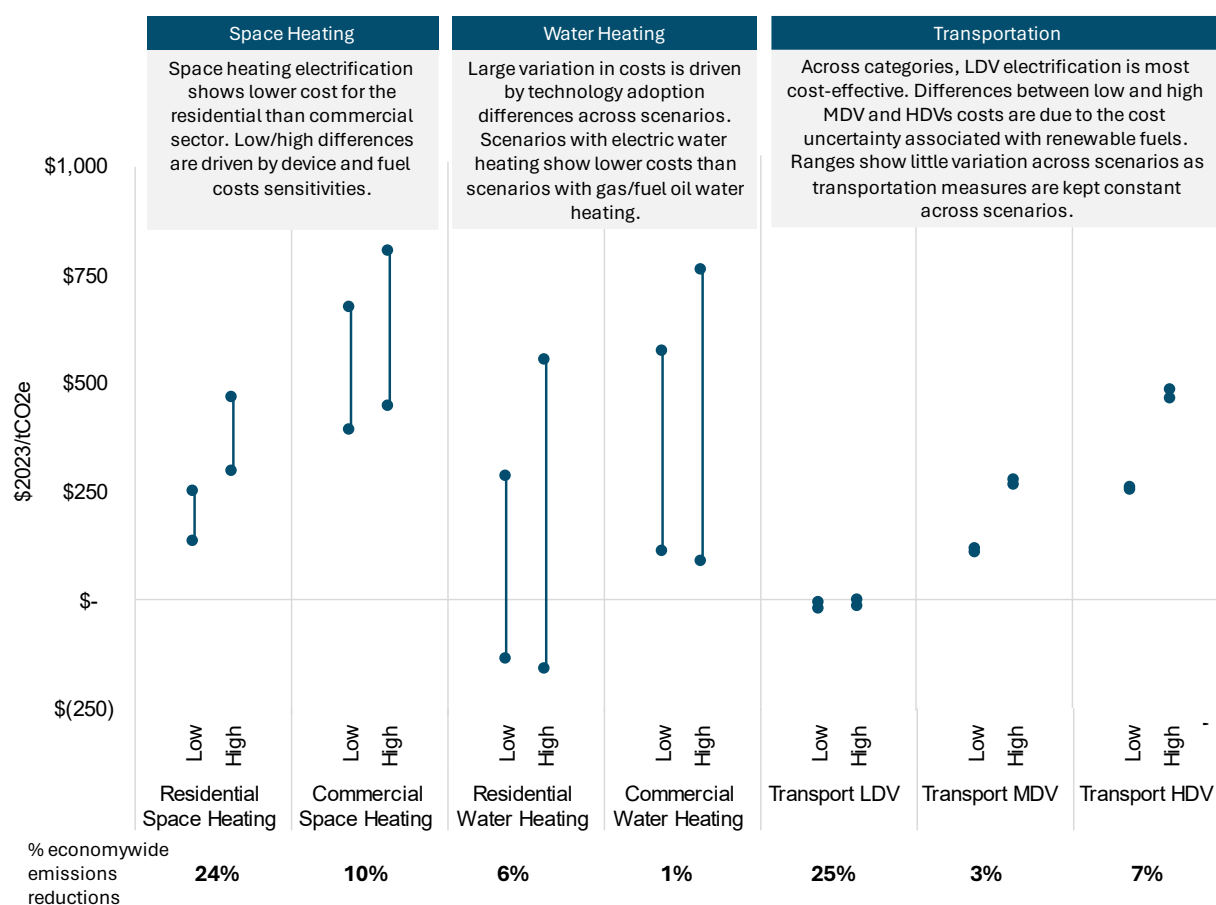
Cost of Abatement

In addition to analyzing incremental total resource costs by scenario, E3 evaluated the costs of GHG abatement associated with decarbonization of key subsectors in the building and transportation sector. In this analysis, abatement costs are defined as the incremental costs to avoid one metric ton of CO₂e compared to a reference scenario. Costs include all components incorporated in the total resource costs analysis (see section Appendix A.4). This type of analysis provides insight into the relative cost-effectiveness of decarbonization measures and can therefore inform potential low-regret, near-term policy decisions. It is important to note, however, that in the longer term, all subsectors need to abate GHG emissions in order to comply with the Act on Climate.

Figure 54 shows a range of average abatement costs by subsector, where the range is determined based on the values of abatement costs found across scenarios. Average abatement costs are

defined as the cumulative (2023-2050) incremental resource costs per subsector (in net present value, accounting for all the cost categories associated with total resource costs), divided by the total GHG abatement in that subsector. This view is not technology-specific, but rather represents a portfolio of technology options dependent on the design of the scenario. For example, in the High Electrification scenario, the space heating subsector is primarily comprised of air source heat pumps, but includes other technologies as well. The figure below therefore primarily provides insight into the relative costs of one subsector over another as well as the variation in subsector costs by scenario, rather than insights into the cost-effectiveness of individual technologies.

Figure 54. Range Of Abatement Costs For Each Subsector Found Across Scenarios. Low = low-bound cost input parameters, High = high-bound cost input parameters.



A few observations can be made from the figure:

- Across categories, electrification of LDVs is most cost-effective. The range in LDV costs shows little variation as transportation measures are kept constant across scenarios, with the majority of LDVs transitioning to electric vehicles.
- Decarbonization of MDVs and HDVs is less cost-effective than LDVs. Across scenarios, a higher part of the MDV and HDV stock is decarbonized through renewable fuels compared to the LDV stock. The differences between low and high MDV and HDVs costs are due to the cost uncertainty associated with renewable fuels.

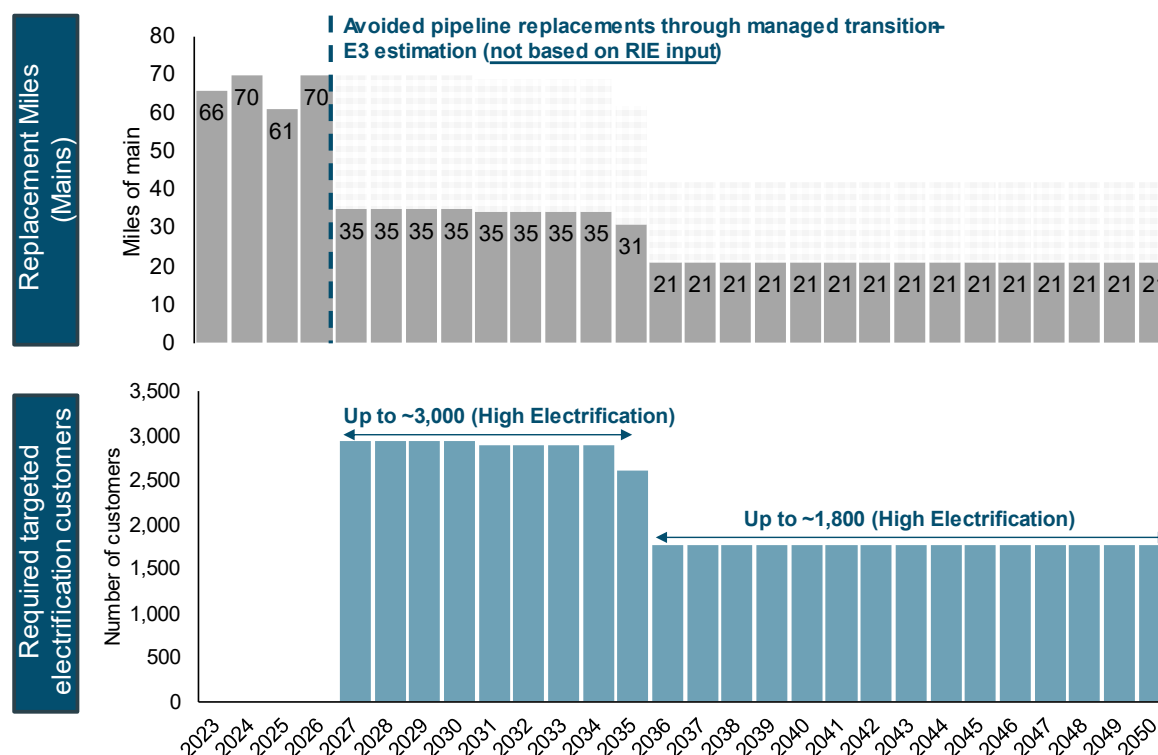
- Decarbonization of space heating demonstrates lower costs for the residential sector than commercial sector. The differences between low and high parameters are driven by device and fuel costs sensitivities.
- There is significant variation in the abatement costs of water heating for both the residential and commercial sector. This variation is primarily driven by the differences in technology adoption across scenarios, since some scenarios (e.g. High Electrification, Staged Electrification) rely more heavily on adoption of heat pump water heaters, while other scenarios rely on water heating through renewable gas (Continued Use of Gas, Hybrid with Gas Backup) or renewable delivered fuels (Hybrid with Delivered Fuels Backup). In Figure 54, the low bound of the range is determined by scenarios that rely more heavily on adoption of heat pump water heaters, which implies that heat pump water heaters are relatively cost-effective decarbonization solutions. In contrast, the high bound of the range is determined by scenarios that rely more heavily on gas or delivered fuel water heating, which implies that these technologies are not a cost-effective solution to decarbonize water heating.

Customer Choice and Implications of a Managed Transition

As described in Chapter 4, the term managed transition in this report refers to the development of neighborhood-specific targeted electrification projects based on gas mains replacement schedules that result in the avoidance of gas system costs. In the scenarios modeled, the analysis assumes a 100% opt-in from customers. The likelihood of this outcome was not modeled or assessed, and implementing a managed transition strategy could require significant changes to customers options. The figure below shows that if 50% of pipeline replacements are avoidable, up to 3,000 customers per year need to electrify their heating system in a targeted manner between 2027-2035. For reference, initial pilot programs conducted by PG&E in California have to date electrified a total of 102 customers.⁹⁷ These “targeted conversions” only apply to scenarios with near-term gas system departures, such as High Electrification, Hybrid with Delivered Fuels Backup and Staged Electrification.

⁹⁷ Presentation by PG&E on The Building Decarbonization Coalition “Future of Building Decarbonization” workshop, page 21: [BDC Presents Neighborhood Scale \(buildingdecarb.org\)](https://buildingdecarb.org)

Figure 55. (Illustrative) Avoided Pipeline Replacement Assumptions And Implications For Number Of “Targeted” Customer Conversions



While a managed transition may avoid some investment in the gas system, it will require substantial top-down coordination and presents several risks, which are not modeled or addressed in detail as part of this study. A few considerations include:

- + **Obligation to serve:** A managed transition strategy requires a 100% opt-in from customers or has significant implications for customer choice, as customers will need to agree to convert all gas appliances to electric and/or geothermal systems. Successful implementation of such projects may require regulatory reforms associated with obligations to serve.
- + **Community engagement.** Achieving a 100% opt-in from customers will likely require significant levels of community engagement. Initial community engagement research by E3, Gridworks and East Bay Community Energy in California found that identifying the appropriate parties to interface with community members may prove difficult, as utilities and local governments are not always viewed as trusted parties and local organizations may have low bandwidth or expertise to engage on these issues.⁹⁸
- + **Safety and reliability:** Maintaining the safety and reliability of the gas distribution system is a core tenant of RIE’s responsibilities and is necessary to continue to serve customers that remain on the gas system. A managed transition will require careful study to determine which segments of

⁹⁸ E3, Gridworks and East Bay Community Energy (June 2023). Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California.

the distribution system can be safely decommissioned while maintaining sufficient gas flow and pressure to reliably deliver gas. These areas for further study are described in Chapter 6.

- + **Cost-effectiveness:** Converting customer gas appliances to electric appliances requires substantial upfront costs, especially when gas appliances may not be at the end of their useful life and fully depreciated. Balancing the benefits of potential avoided costs from decommissioning and the costs of customer electrification will be a key challenge in a managed transition. Some studies have found that targeted electrification projects result in net societal benefits, but the cost-effectiveness is highly dependent on factors such as electric distribution upgrade requirements, upfront equipment costs, and gas system density.⁹⁹ Cost-effectiveness could further be affected by the potential need to provide “buy-out” incentives in order to achieve a 100% opt-in from customers.
- + **Funding gap:** Regardless of societal benefits, additional funding will be needed to make targeted electrification cost-effective from a customer perspective. Studies show that the upfront costs of equipment still lead to a net cost from a participant perspective, especially as project upgrades need to occur before equipment end-of-life.¹⁰⁰ This means that there is a potential misalignment between societal benefits and customer benefits that needs to be addressed in order to make targeted electrification projects attractive for customers.

Affordability and Implications for Energy Burden

As demonstrated in Chapter 4, a reduction in gas demand leads to higher gas rates for remaining customers, which could lead to spiraling energy bills for gas customers. As the upfront costs for electrification are high, this effect could create equity issues as low-income customers are less likely to be able to afford electrification and are left on the gas system.

E3 evaluates customer affordability by assessing customer energy bills and levelized upfront costs for various customer types, such as a gas customer, an all-electric customer, a hybrid gas customer, and a hybrid delivered fuels customer. In addition to the impact of adopting new heating technologies on energy bills, E3 assesses the impact of weatherization measures on bills and the impact of upfront costs.

Cost Of Adopting Decarbonization Measures Today

Today, as illustrated on Figure 56, an all-electric customer adopting an ASHP and other electric appliances experiences approximately 25% higher monthly energy bills than a gas customer that uses gas as primary heating source. This increase is primarily driven by relatively high electricity rates compared to gas rates, as discussed in Chapter 4. Rhode Island has one of the highest electricity rates in the country today (0.29 \$/kWh in 2023 compared to the approximately 0.15 \$/kWh U.S. average¹⁰¹), which means that despite the efficiency of heat pumps, efficient electric heating does

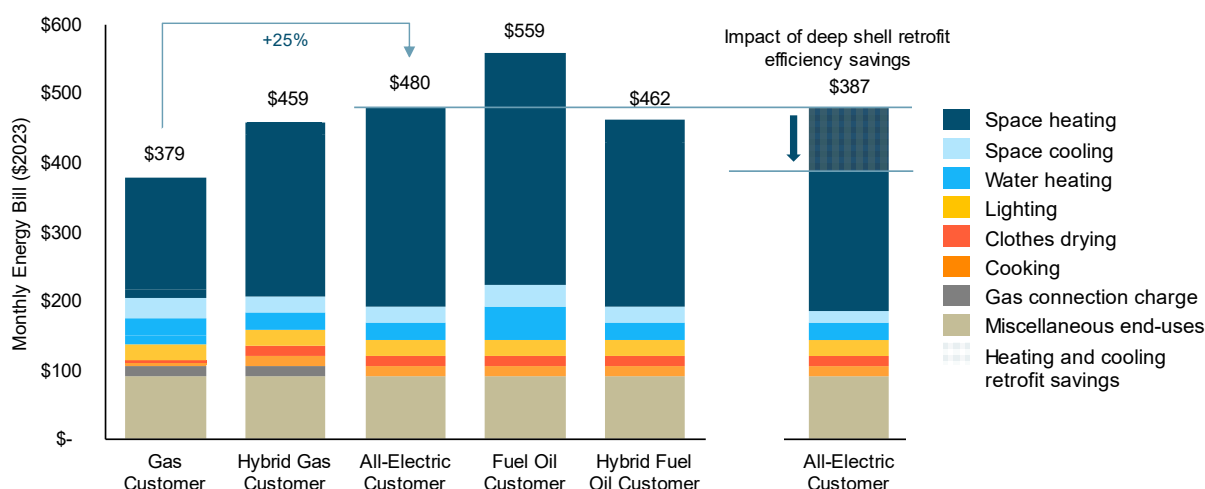
⁹⁹ See, for example: E3 - [Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California](#);

¹⁰⁰ Ibid

¹⁰¹ Based on EIA Table 5.6.A, Table 2.10

not lead to a reduction in energy bills for customers currently on gas heating. In contrast, efficient electric heating does lead to a significant reduction in bills for customers using delivered fuels as their primary source of heating, because of the high costs associated with delivered fuels. In addition, as illustrated on Figure 56, a customer transitioning from gas to electric heating and undergoing a deep shell weatherization retrofit that reduces energy consumption would experience monthly energy bills that are similar to a gas customer.

Figure 56. Residential Monthly Energy Bills in 2023



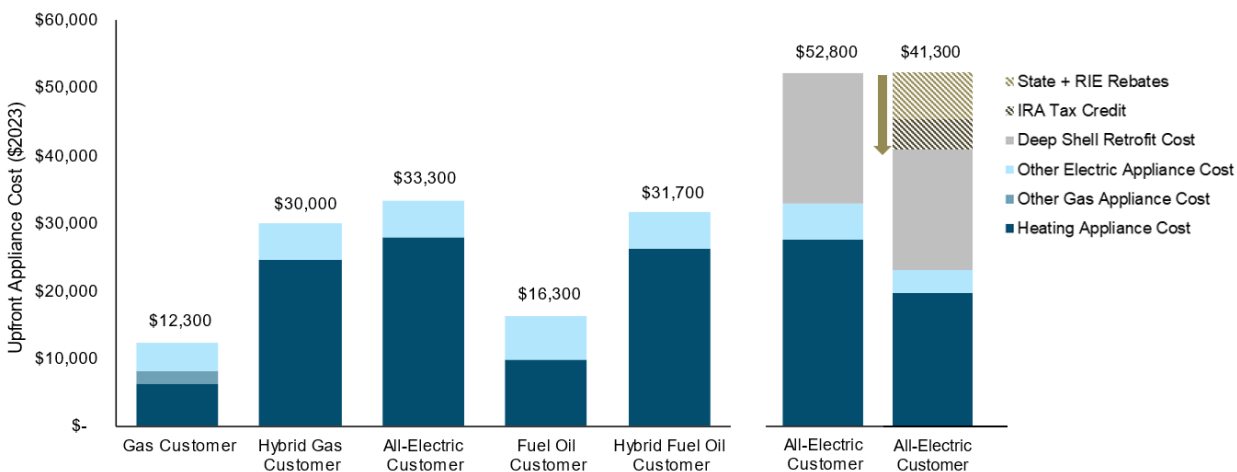
In addition to monthly energy bills, customers transitioning away from the gas system will face significant upfront costs for electric appliances. Purchasing ASHPs and other electric equipment today is more expensive than traditional gas appliances¹⁰², leading to costs that are almost three times higher for an all-electric customer compared to a gas customer. Furthermore, building shell weatherization retrofits that achieve up to 30% energy savings in space heating and cooling are necessary investments to reach Rhode Island’s climate goals. E3 estimates that a deep shell weatherization retrofit would cost approximately \$20,000 for an average-sized single-family home, presenting a sizeable upfront cost barrier to customers (see Figure 57).¹⁰³

Federal and state incentives can mitigate the affordability challenge for customers, but current incentives are insufficient to bring electric heating appliances to cost parity with their gas appliance counterparts. The Inflation Reduction Act (IRA) provides tax credits for heat pumps and weatherization upgrades until 2033. Rhode Island State offers rebates for heat pumps and an electric panel upgrade and RIE also provides incentives for heat pumps.

¹⁰² E3 applies its default or base case cost assumption for ASHP and hybrid ASHPs in its energy bill calculations.

¹⁰³ Note that in the PATHWAYS analysis, by 2050 nearly 35% of customers are assumed to receive a deep shell retrofit, and 60% a “basic” (cheaper) shell retrofit. These numbers are similar across scenarios. A basic shell retrofit is expected to cost approximately \$6,000 for an average-sized single-family home, leading to a 16% saving in heating service demand.

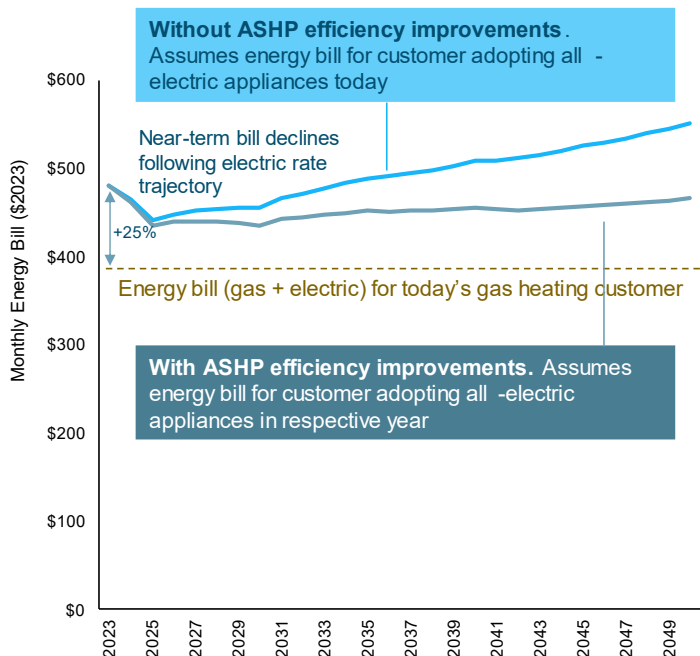
Figure 57. 2023 Upfront Appliance Costs associated with Decarbonization Measures



Costs Of Adopting Decarbonization Measures Over Time

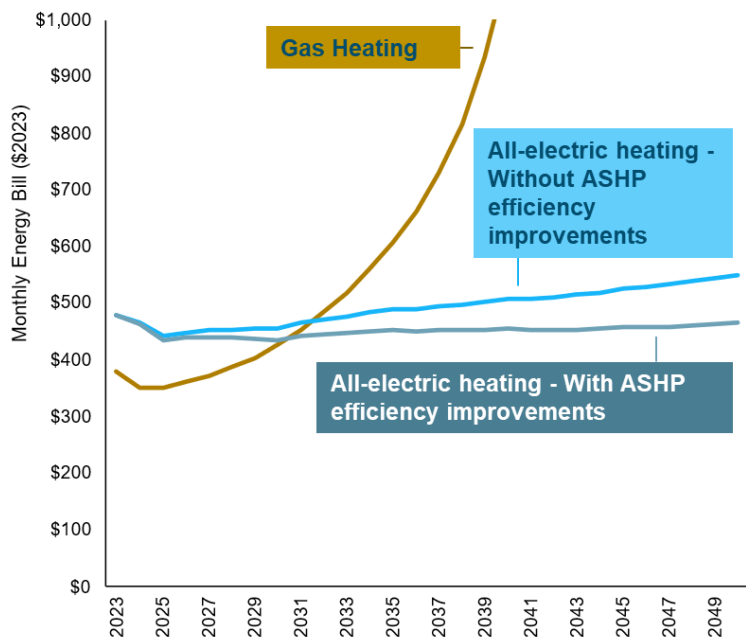
In all decarbonization pathways, energy bills increase as gas and electric rates are expected to rise. As electric rates increase, it becomes less attractive to adopt electric heat pump equipment, especially for customers adopting heat pumps in the near term with current levels of technology efficiency. However, as heat pump efficiencies are expected to improve over time, despite electric rate increases customers adopting heat pumps in later years will not experience significant energy bill increases from today's level (see Figure 58).

Figure 58. Single Family Residential Monthly All-Electric Customer Bill under the High Electrification Scenario



As customers exit the gas system in a High Electrification scenario, adopting all-electric equipment becomes more cost-effective *in relative terms* in comparison to gas bills under the current regulatory framework. This dynamic is demonstrated on Figure 59, which shows the same electric heating customer energy bills as Figure 58 but adds a comparison to the energy bills for a customer that remains connected to the gas system in the High Electrification scenario. This figure shows that while electric heating bills remain relatively steady (assuming heat pump efficiency assumptions), the bills for a gas heating customer rise substantially because of delivery rate increases. As a result, all-electric heating becomes more cost-effective in relative terms compared to gas heating around the early 2030s.

Figure 59. Single Family Residential Monthly All-Electric Customer Bill compared to Gas Customer Bill under the High Electrification Scenario



The same dynamic is illustrated for all scenarios in Figure 60. This figure shows that residential gas customers face spiraling gas rates and untenable energy bills in the long-term in all pathways except for Continued Use of Gas. Similarly, commercial customers experience spiraling gas rates, though to a lesser extent than residential customers (see Figure 61). Because of that dynamic, by the early 2030s it becomes more affordable for residential customers to electrify their homes as most of the costs of the gas system are shifted to fewer remaining gas customers. However, it is important to note that following these dynamics, all customer energy bills are expected to go up from today's levels.

Figure 60. Residential Monthly Energy Bills under Decarbonization Pathways

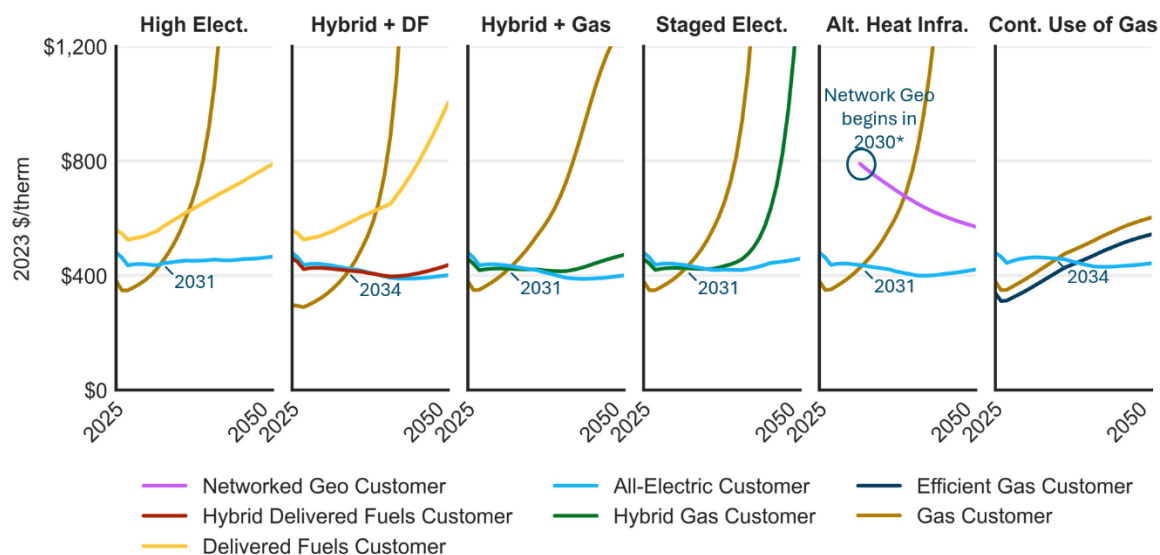
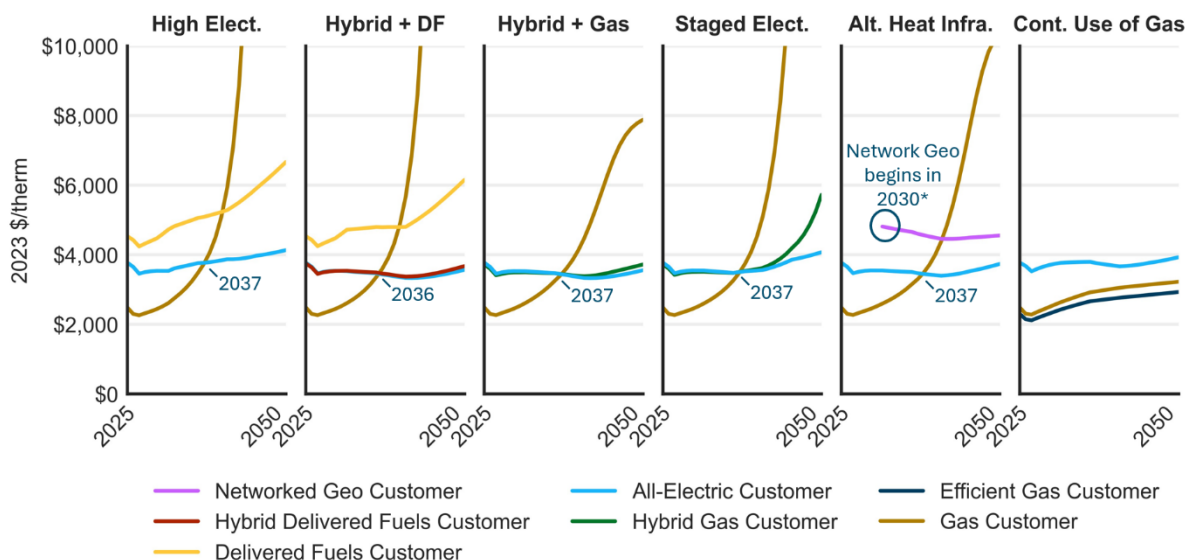


Figure 61. Small Commercial Monthly Energy Bills under Decarbonization Pathways



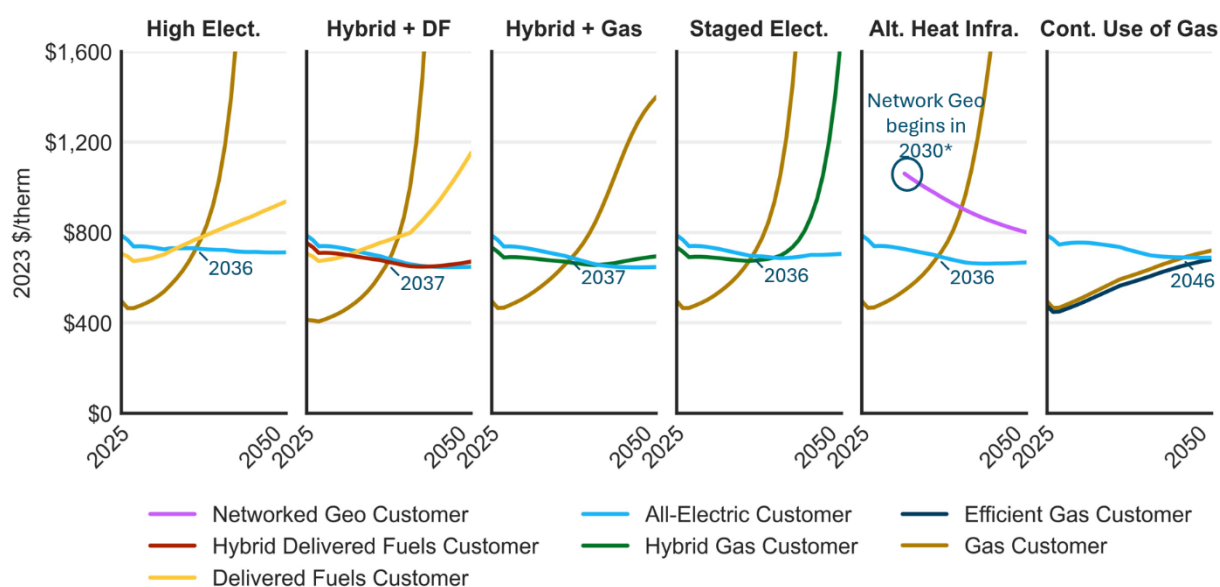
**Note: Networked geothermal systems are assumed to come online in 2030. Networked geothermal customers initially face very high energy bills as the system costs are spread among few customers. Over time, energy bills are forecasted to decline for these customers and to become more affordable than residential gas customer bills in 2038 in the Alternative Heat Infrastructure scenario.¹⁰⁴*

While energy bills become more cost-effective for customers electrifying, the upfront cost of electric appliances push back the inflection point for when it becomes more affordable to be an all-electric

¹⁰⁴ The small commercial customer's electricity use is dominated by non-heating loads, emphasizing the impact of high electricity rates and limiting the bill savings from a networked geothermal heating system.

or hybrid customer rather than a gas heating customer. Total energy costs, shown in Figure 62, illustrate energy bills with *levelized* upfront costs included. The levelized costs in this analysis reflect the cost to pay back the appliances on a monthly basis over the appliances' lifetime *plus* interest, equivalent to a situation in which a customer would lease or finance the cost of equipment. Showing both energy bills and levelized upfront costs on a monthly basis provides a perspective on the total cost of ownership for customers that is associated with the adoption of decarbonization solutions. With the addition of upfront costs, the inflection point for when it becomes cheaper to transition to all-electric is moved the mid-2030s, assuming no changes to the regulatory paradigm that prevent gas rates to increase.

Figure 62. Residential Monthly Energy Costs (Energy Bills + Levelized Upfront Costs) including Gas to All-electric Inflection Year



Building shell weatherization retrofits save customers money on their energy bills by reducing the energy needed for space heating and cooling, however they add significant upfront costs. If customers adopt deep shell weatherization retrofits, they would experience similar total energy costs to those shown in Figure 62. The sizeable upfront costs are mostly balanced by the monthly energy bill savings customers would receive.

Energy Burden

Long-term affordability for gas customers is a particular challenge across all decarbonization pathways. There is a significant cost shift risk as customers transition off the gas system leaving fewer customers, likely low-to-moderate income customers, bearing the burden of gas system costs. This shift is especially apparent when considering customer energy burden, the percentage of a customer's gross income that is spent on household energy bills.

Today, a gas customer experiences an energy burden of 5.7%, which is expected to increase over time across all scenarios, as a result of increased gas delivery rates or an increase in the variable

costs of gas.¹⁰⁵ On the other hand, all-electric and hybrid customers do not experience significant changes in energy burden. Today, an all-electric customer experiences an energy burden of 7.2%, reflecting 25% higher energy bills than gas customers. Hybrid delivered fuels and hybrid gas customers face a current energy burden of approximately 6.9% each. In the High Electrification scenario, all-electric customers' energy burden would decline to 5.9% by 2050, reflecting the adoption of more efficient technology over time. Hybrid delivered fuels customers' and hybrid gas customers' energy burdens would similarly dip to 5.6% and 6.1% by 2050 in the Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup scenarios, respectively. However, due to spiraling gas rates, gas customers left on the system face a skyrocketing energy burden in scenarios with high electrification. For example, gas customers face an energy burden of over 700% by 2050 in the High Electrification scenario. The energy bills clearly place an untenable burden on customers that will need to be mitigated. Even in the Continued Use of Gas scenario, efficient gas customers face a 25% higher energy burden (7.2%) in 2050 than they do in 2023 as a result of changes in the variable costs of gas.

Workforce Impacts

A detailed quantitative workforce impact assessment was beyond the scope of the Technical Analysis. Instead, E3 provides qualitative considerations on the potential benefits or challenges to the Rhode Island workforce resulting from decarbonization scenarios. More comprehensive models and studies that analyze the impact of decarbonization on the local economy and jobs do exist and are recommended for use in further study. For example, New York's Scoping Plan included modeling of the jobs impacts of net zero decarbonization scenario,¹⁰⁶ and Massachusetts developed a Clean Energy Workforce Needs Assessment aligning workforce needs with the state's decarbonization goals.¹⁰⁷

In E3's qualitative review of workforce impacts, two types of impacts were considered:

- The impact of decarbonization scenarios on the gas distribution workforce, given the focus of the Docket on the gas distribution system.
- The impact of decarbonization scenarios on the broader workforce, specifically related to jobs required to install building shell weatherization packages, heat pumps, and other distributed energy resources.

¹⁰⁵ Energy burden is calculated for a customer making the area median income of approximately \$80,000 in 2023 and with an annual income growth rate of 0.60%. U.S. Census Bureau. QuickFacts Rhode Island. <https://www.census.gov/quickfacts/fact/table/RI,US/INC110222>

¹⁰⁶ Chapter 7. Just Transition of New York's Scoping Plan (2022). Available online: <https://climate.ny.gov/resources/scoping-plan/>

¹⁰⁷ Available online: <https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment>

Gas Distribution System

The decarbonization scenarios assessed in the Technical Analysis have different impacts on the role and use of the gas system, with likely differences in the associated workforce. Whereas Continued Use of Gas and Hybrid with Gas Backup keep the gas distribution system maintained in the long term, the other scenarios see a decline in gas infrastructure use. These scenarios are likely to see a reduction in the long-term need to operate and maintain the distribution system, with potential consequences for the workforce. In E3's revenue requirement model by 2050, RIE's operations and maintenance expenses associated with the gas distribution system are reduced by approximately 40% in scenarios with high levels of electrification compared to today as a result of customer departures, and over 50% with high levels of electrification in a managed transition. However, studies have indicated that even in scenarios focusing on long-term electrification, there are labor requirements associated with decommissioning of the gas system that require a temporary increase in workforce.^{108,109} In addition, in all scenarios with gas throughput declines, there is an ongoing need to perform safety and reliability activities, which means that any changes to the gas distribution system workforce are likely to only materialize in the long term as segments from the system are decommissioned. As investigated by Economy League and the Building Electrification Institute in the City of Philadelphia, the transition to decarbonization takes decades, and current gas workers are not at risk of losing their job in the near term.¹¹⁰

Broader Job Impacts From Decarbonization

Many studies have analyzed the impact of achieving a net zero economy on employment in the United States. For example, Decarb America found that decarbonizing the US economy will create a net increase of over 2 million jobs by mid-century, primarily driven in the near-term by the energy efficiency sector because of the ready access to efficiency technologies.¹¹¹ According to the 2023 Rhode Island Clean Energy Industry Report, Rhode Island employed 14,511 clean energy workers in 2022, with just over half of jobs in the energy efficiency technology sector.¹¹² Before the COVID-19 pandemic, all clean energy sectors, including energy efficiency, efficient heating and cooling, renewable energy, clean transportation and solar and wind, saw significant increases in year-over-year employment, and post-COVID numbers have started to pick up again.¹¹³

¹⁰⁸ Oliphant, Elizabeth. Electrification Impact Assessment: A Preliminary Analysis of the Utility Costs & Staffing Impact to Electrify All Single-Family Residences in Palo Alto. <https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilitiesadvisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2020/11-04-2020-special/id-11639-item-no-3.pdf>. Accessed January 8, 2021.

¹⁰⁹ Economy League and the Building Electrification Institute (2023). Philadelphia Building Decarbonization Workforce Impacts and Opportunities. <https://www.economyleague.org/resources/philadelphia-building-decarbonization-workforce-impacts-and-opportunities>

¹¹⁰ Ibid

¹¹¹ Decarb America (2022). Employment Impacts in a Decarbonized Economy. <https://decarbamerica.org/wp-content/uploads/2022/06/Employment-Impacts-in-a-Decarbonized-Economy.pdf>

¹¹² BW Research (2023). 2023 Rhode Island Clean Energy Industry Report. <https://energy.ri.gov/sites/g/files/xkgbur741/files/2024-01/2023%20Clean%20Jobs%20Report.pdf>

¹¹³ Ibid

In the Technical Analysis, the increase in decarbonization technologies is unprecedented across scenarios in Rhode Island. This includes adoption of efficient heating and cooling technologies such as heat pumps, electric vehicles, renewable energy, and energy efficiency measures such as weatherization. For example, the scenarios see an increase in heat pump adoption 5 to 10 times higher than today's adoption of heat pumps and levels of building shell retrofits that far exceed participation levels from current energy efficiency programs in the state. Although not quantified in this study, these adoption levels imply a significant growth of the clean energy workforce across all scenarios in the next decades to ensure successful implementation. In the workforce analysis of the New York Scoping Plan, over half of the jobs added before 2030 were in buildings, with the largest increases in residential HVAC and building shell installations.¹¹⁴

In Massachusetts, MassCEC projected a growth in a clean energy workforce of 37% by 2030 while highlighting eight key gaps in the workforce needed to meet future occupational needs of the clean energy transition.¹¹⁵ These gaps include additional needs for electricians, HVAC installers, electric power line installers, construction laborers, building inspectors, insulation workers, cost estimators and pipelayers, plumbers, pipefitters and steamfitters. More research is needed to understand the extent to which Rhode Island currently has the workers and skills necessary to install the decarbonization technologies as required to comply with the Act.

Air Quality

In addition to greenhouse gases, the combustion of fuels (including renewable fuels) produces emissions of pollutants, such as PM 2.5 and Nox, that negatively impact air quality. In the state of Rhode Island and elsewhere across North America, air quality impacts are associated with tailpipe emissions in the transportation sector, and combustion of gaseous and liquid fuels in the electricity, industrial and buildings sector. In addition to health impacts from outdoor tailpipe emissions, studies have demonstrated implications from indoor combustion of fuels on public health. For example, Gruenwald et al. (2023) found a relationship between the use of indoor gas stoves for cooking and an increased risk of asthma among children.¹¹⁶ Historically, emissions of pollutants like PM 2.5 have been disproportionately concentrated in low-income and/or minority areas.¹¹⁷

A detailed quantification of the direct impacts of the scenarios on air quality benefits was beyond the scope of this work. Models that quantify these types of dynamics do exist; for example, the co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) estimates health

¹¹⁴ Chapter 7. Just Transition of New York's Scoping Plan (2022). Available online:

<https://climate.ny.gov/resources/scoping-plan/>

¹¹⁵ MassCEC (2023). Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment. Available online:

https://www.masscec.com/sites/default/files/documents/Powering%20the%20Future_A%20Massachusetts%20Clean%20Energy%20Workforce%20Needs%20Assessment_Final.pdf

¹¹⁶ Gruenwald, T., Seals, B., Knibbs, L. and Hosgood III, D. "Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States". *Int. J. Environ. Res. Public Health* 2023, 20(1), 75.

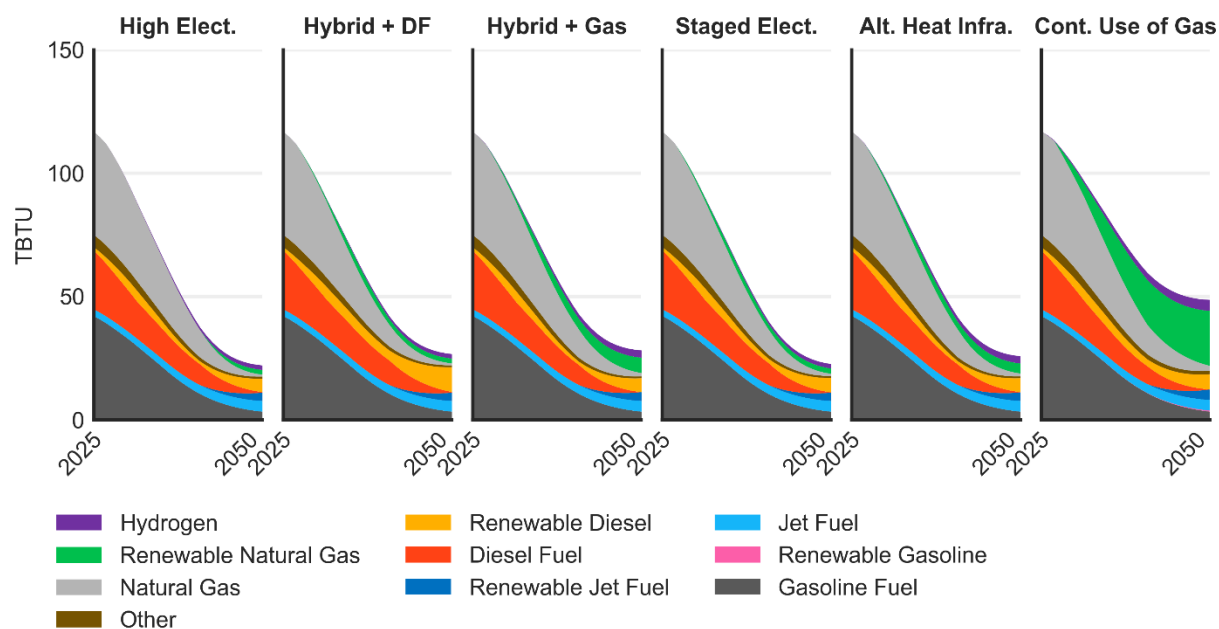
¹¹⁷ See, for example: Tessum, Christopher W., et al. "PM2.5 pollutants disproportionately and systemically affect people of color in the United States." *Science Advances* 7.18 (2021): eabf4491

impacts of changes in air pollution emissions as a result of decarbonization measures at granular level. In the Technical Analysis, E3 assumes that the reduction of fuel combustion has a directly positive impact on air quality in the state of Rhode Island and therefore, the reduction in fuel combustion, including renewable fuels, across scenarios is used as a proxy to qualitatively determine the effects of scenarios on air quality. This analysis is done at the statewide level – additional research that assesses impacts on a regional basis would provide more insights into the extent to which emissions reductions directly benefit low-income disadvantaged communities (LIDACs).

Figure 63 shows the combustion of fuels across scenarios over time, which shows the reduction in fuel combustion across all sectors. These figures show that fuel combustion declines significantly in all scenarios, which is primarily due to the high levels of efficiency and electrification in the transportation and buildings sector. Statewide, the combustion of fuels reduces between 65-85% across scenarios, with the highest level of combustion left in the Continued Use of Gas scenario mostly as the result of differences in the building sector. In the buildings sector specifically, shown earlier in Chapter 4, the highest levels of combustion take place in the Continued Use of Gas scenario, followed by the Hybrid with Gas Backup and Hybrid with Delivered Fuels scenarios that leave combustion of fuels to serve heating demands in winter.

The overall decline in combustion across scenarios implies that complying with the Act on Climate has an overall positive impact on air quality and ultimately, health in the state of Rhode Island. Scenarios with higher levels of electrification are likely to see higher levels of benefits than scenarios that leave higher levels of combustion of fossil or renewable fuels.

Figure 63. Fuel Combustion across Scenarios Over Time



Reliance on Regional Fuel Supply

The decarbonization scenarios included in the Technical Analysis show variations in the type of energy used as input fuels in the heating sector, and therefore differ in where energy supply is coming from. Scenarios that rely on electrification source energy supply from an increasing share of renewable electricity, whereas scenarios that rely on renewable fuels source energy supply from a variety of emissions-compliant sources, including biomass resources to produce renewable biofuels and hydrogen produced through renewable electricity. The evaluation of reliance on regional fuel supply provides two types of insights:

- + The extent to which Rhode Island will depend on national and international market dynamics that determine the supply and costs of fuels. Given its size in the market, Rhode Island is likely to be a “price taker”, having little influence over demand and supply dynamics in the broader market, and therefore is at risk of exposure to market fluctuations outside of the state’s (and region’s) control.
- + The extent to which the transformation of energy supply may lead to local economic development opportunities. Studies have demonstrated a positive relation between renewable energy production and economic development¹¹⁸, which indicates that reducing dependency on fuels beyond state and regional borders may lead to economic opportunities. Note that there are also other considerations to take into account that indicate risks associated with this dependency, for example as described below in the evaluation criterion on the pace of electric system expansion.

Renewable Electricity Generation

In the electricity sector, load increases need to be met with electricity generation within or connected to the ISO-NE system. In addition, the Rhode Island RES defines eligible renewable resources as generation units that are within the ISO-NE control area, or generation units that are able to prove that the energy produced by the generation unit is delivered into the ISO-NE area for consumption by New England customers.¹¹⁹ This means that as Rhode Island achieves its 100% RES goal by 2033, all load increases from electrification of heating sources need to be met by renewable electricity generation within the ISO-NE region. Although the RES does not prescribe that generation needs to occur within the state, the RES within Rhode Island and adjacent New England states will ultimately balance demand for and supply of renewable electricity within the New England region.

Scenarios that rely on electrification of heating to achieve the Act on Climate, such as High Electrification, Staged Electrification and to some extent Hybrid with Gas Backup, Hybrid with Delivered Fuels Backup and Alternative Heat Infrastructure, will see a shift from dependency on out-of-state fuels, such as natural gas and delivered fuels, to more dependency on in-region electricity. Although this trend puts pressure on electric system requirements, especially for scenarios with high

¹¹⁸ See, for example: World Resources Institute (2022). Federal policy Building blocks to support a just and prosperous new climate Economy in the United States

¹¹⁹ RI Gen. Laws § 39-26-5. <http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26/39-26-5.htm>

levels of all-electric heat pump adoption, it is also more likely to lead to regional economic development opportunities than scenarios that continue to source fuels from out of region.

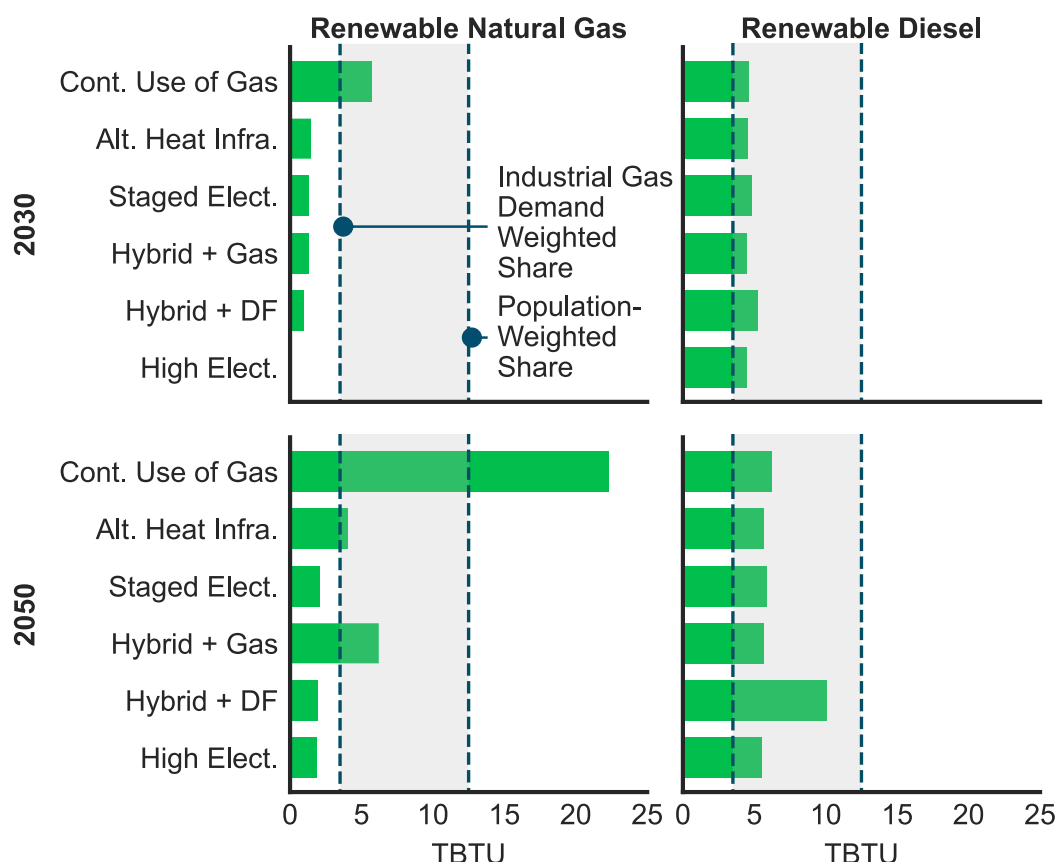
Renewable Fuels

Several studies estimate that New England is likely to have one of the lowest levels of biomass resources available for conversion into renewable fuels in the United States.¹²⁰ Scenarios that rely heavily on renewable fuels are therefore likely to source these fuels from out of region. While the import of fuels for energy purposes is common in Rhode Island today, this means that scenarios with higher levels of renewable fuels to serve heating demand are more likely to continue to rely on out-of-region resources in contrast to scenarios with higher levels of electrification that transition more strongly to in-region supply of energy for heating purposes. In particular, it is likely that the capital investments necessary to produce renewable fuels will occur out of region, while Rhode Island continues to rely on local infrastructure to deliver these fuels.

Both nationally and internationally, the supply of renewable fuels if sourced from biomass feedstocks is constrained by competition for critical land uses, which puts pressure on the availability and costs of resources as demand across sectors grows. Shown by the light gray bands in Figure 64, E3 estimated the maximum amount of biomethane that could be produced from biomass resources based on the 2016 DOE Billion Ton Report using different percentages of availability of biomass that could reasonably be allocated to the state of Rhode Island. These bands assume that a proportion of biomass resources produced in the eastern United States is entirely converted into biomethane or renewable diesel for use in Rhode Island.

¹²⁰ See, for example: *US DOE (2016). Billion Ton Report*;
M.J. Bradley (2019). Renewable Natural Gas: Potential Supply and Benefits;
American Gas Foundation, prepared by ICF (2019). Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment.

Figure 64. Renewable Natural Gas and Renewable Diesel Demands for 2030 and 2050.
The shaded bands represent the allocation of biomass to Rhode Island, converted into the indicated renewable fuel, based on different allocation methods.



Two primary considerations apply to scenarios that fall within or beyond the allocation range:

- Reliance on non-commercialized fuels.** Scenarios with high demands for renewable fuels are likely to procure fuels sourced from non-biomass sources, such as synthetic natural gas or synthetic diesel. The production of these synthetic fuels requires production of green hydrogen as well as availability of a carbon-neutral source of CO₂ from either biorefineries or direct air capture. These production methods have a relatively low level of commercialization today (see section on Technology Readiness).
- Higher costs.** The amount of fuels that can be procured for use in Rhode Island will ultimately depend on market mechanisms. A regional or national market for renewable fuel credits may emerge that would broaden the range of eligible sources or regions. However, as seen in other regions, credit prices fluctuate based on demand and may significantly drive up the cost of renewable fuels.

Figure 64 demonstrates that out-of-state resources may be required for Rhode Island to meet its goals, particularly in those scenarios where Rhode Island relies heavily on the use of renewable fuels to meet its emissions targets. Scenarios that retain high levels of gas demands, particularly

Continued Use of Gas, may rely on currently non-commercialized fuels as early as 2030 resulting from constraints in availability of biomass resources. In addition, all scenarios rely on the use of renewable diesel to some extent, at minimum to comply with the Biodiesel Heating Act by 2030. The demand for renewable diesel may drive up the costs or need for synthetic fuels as competition across sectors and regions increases.

While the above results should not be interpreted as prescriptions or forecasts of renewable fuel demand or availability for the state, they do show increased risk of dependence on renewable fuels for the Continued Use of Gas scenario, and to a lesser extent the Hybrid with Gas Backup and Hybrid with Delivered Fuel Backup scenarios, in the long term. As maximal production of biomethane or renewable diesel in these scenarios is likely unable to satisfy renewable fuel demands by 2050, Rhode Island would need to procure other types of emissions-compliant fuels, such as synthetic fuels which have a lower level of commercialization today and are likely to be available at higher cost. Production of these fuels through primarily out-of-state capital investment will rely on market and policy dynamics that Rhode Island will have little control over.

The significant uncertainty associated with the availability and cost of renewable fuels, as well as the emissions impact of fuels under different accounting assumptions, suggest an increasing need for policies that mitigate risk associated with renewable fuels. Such policies can be discussed and addressed in the Policy Development phase of this proceeding.

Technology Readiness

The scenarios designed for the Technical Analysis rely on a number of decarbonization technologies, varying from heat pumps, to networked geothermal systems, to use of technologies required to produce renewable fuels. These technologies have varying levels of “technology readiness”: While some technologies are commercially available and mature, others are still in demonstration phase. The level of commercialization or extent to which a technology is ready for large-scale deployment determines the risk associated with relying on a technology to achieve the emissions targets required to comply with the Act on Climate.

The International Energy Agency (IEA) has established a Technology Readiness Level (TRL) scale for decarbonization measures and keeps a detailed database of TRL levels of clean energy technologies.¹²¹ In this framework, technologies with a TRL of 11 are ready to scale and fully commercialized, while options lower than that need Research and Development (R&D) and/or commercialization support, as outlined in the table below. E3 relied on IEA’s TRL scale and assessment to evaluate the level of technology readiness of key measures used in the design of decarbonization scenarios.

¹²¹ See: <https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide>

Table 13. IEA's Technology Readiness Level Scale with Clean Energy Technology Examples

TRL	Category	Example
11	Mature – Proof of stability reached	High-efficiency gas furnaces
9-10	Early adoption – commercially available; further improvement and integration needed	Cold climate Air-Source Heat Pumps
7-8	Demonstration – pre-commercial or first-of-a-kind commercial deployment	Networked Geothermal Systems
5-6	Large prototype – Components or full prototype proven in conditions to be deployed	Biomass gasification and Fischer-Tropsch to produce biofuels
4	Small prototype – prototype proven in test conditions	Integrated heat pumps with storage for heating and cooling
1-3	Concept – application in idea or validation phase	Direct hydrogen combustion in jet turbines

In designing scenarios, E3 and other deep decarbonization researchers generally screen out technologies that are low (<5) on the TRL scale because of their speculative nature and the short time horizon of mid-century climate goals. Therefore, the scenarios designed for the Technical Analysis typically have a TRL of 5 or higher, but the time required for key technologies deployed across the scenarios to mature still varies.

Figure 65 provides an overview of the TRLs of key decarbonization technologies used across scenarios, their expected ramp-up of deployment in the scenarios and the reliance of scenarios on these technologies. This figure shows that the High Electrification and Staged Electrification scenarios largely rely on technologies with TRLs of 9 or higher, such as cold-climate air source heat pumps. The High Electrification scenario additionally sees some level of reliance on networked geothermal systems, which are deployed at a much larger scale in the Alternative Heat Infrastructure scenario. Given the fact that this scenario already sees significant ramp up of this technology by the late 2020s, this scenario has a relatively high risk that the technology would not be available at commercial scale in time for it to achieve the levels of emissions reductions as projected in this scenario.

The Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup scenarios are likely to rely to some extent on the use of synthetic fuels (biodiesel and gas respectively) that have relatively low levels of commercialization, depending on the availability of fuels as discussed in the previous section. However, the deployment of these technologies is likely only required later in time. It is important to note that if an alternative compliance mechanism for renewable fuels arises, this assessment is not strictly accurate. However, in such case, it is likely to assume that a negative emissions technology such as Direct Air Capture needs to be deployed (either in- or out-of-state) that has similar levels of technology readiness.

Figure 65. TRLs of Key Technologies and Reliance on Technology across Scenarios

				Reliance on technology across scenarios					
TRL = Technology Readiness Level				High Elec.	Hybrid + DF	Hybrid + Gas	Staged Elect.	Alt. Heat Infra.	Cont. Use of Gas
		TRL	Ramp-up						
Cold-Climate ASHP	Res/Small Commercial	10	2020s	●	●	●	●	●	●
	Large Commercial	8	2020s	●	●	●	●	●	●
Networked Geothermal	Residential/commercial	7	2030s	●	●	●	●	●	●
Efficient Gas Appliances	Condensing furnaces	11	2020s	●	●	●	●	●	●
Biofuels	Biodiesel	10	2020s	●	●	●	●	●	●
	RNG - Anaerobic digestion	10	2030s	●	●	●	●	●	●
	RNG - Bio-gasification	7	2030s	●	●	●	●	●	●
Hydrogen Including for electric generation	Alkaline electrolyzers	9	2030s	●	●	●	●	●	●
	H2 blending	7	2030s	●	●	●	●	●	●
	Dedicated hydrogen network & use	6	2040s	●	●	●	●	●	●
Synthetic Fuels	Synthetic biodiesel	6	2040s	●	●	●	●	●	●
	Synthetic gas with climate-neutral carbon	6	2040s	●	●	●	●	●	●

● High
● Medium
● Low
○ Not used

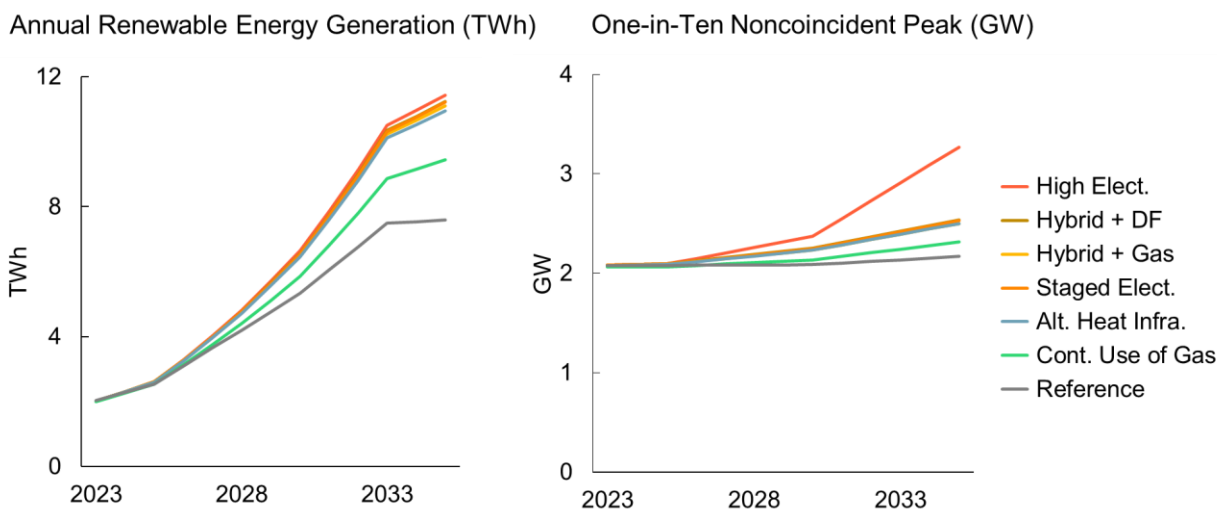
Pace of Electric System Expansion

All decarbonization scenarios include significant levels of electrification in transportation and buildings, leading to an unprecedented buildout in electric system infrastructure to meet new demands. All scenarios require significant renewable buildouts to comply with 100% RES and requirements from other states. To serve Rhode Island’s increasing load and meet the 100% RES, as well as similar demands throughout the region, higher levels of incremental renewable generation are required especially in scenarios with high levels of heat pump adoption (Figure 66). Although Rhode Island is a relatively small player in ISO New England, the increasing demand for renewables will require building additional resources in the region. This will tap into the potential onshore wind resources that are relatively lower in cost but limited due to land constraints, as well as the solar or offshore wind resources that are more abundant but have experienced more than 20% cost increases or project cancellations in the last few years due to supply chain disruptions.

As renewable procurement ramps up in the near term and to support the higher peak demands from electrification, transmission and distribution (T&D) infrastructure needs to be significantly expanded (Figure 66). The increase in peak demand driving T&D upgrades is especially pronounced in the High

Electrification scenario which leads to a +/- 1 GW increase in required electric system capacity in the next decade.

Figure 66. Near-Term Pace of Electrification Shown as Changes in Renewable Energy Generation and One-in-Ten Noncoincident Peak (2023-2035)



Rhode Island already has a system peak that is twice as high as the average demand on the system, which means that the full capacity of the system is only utilized during periods of high demand. Increasing peak demands from electrification will require T&D system upgrades but at the same time, in most scenarios, will reduce the peak-to-average ratio under higher proportion of annual load growth, as more electricity is used throughout the year, including in non-peak hours. This increase in system utilization is expected to put downward pressure on average electric rates in the state. The reduction in peak-to-average ratios is especially profound in scenarios that are able to avoid system peaks, through the use of gas or delivered fuel heating as backups during the coldest hours of a year.

6. Key Study Takeaways

The Technical Analysis shows that achieving the Act on Climate in Rhode Island requires a transformation of energy use across all sectors in the state, and significantly impacts the use and role of the gas distribution system. This chapter provides key takeaways with regard to the questions raised in the Docket scope that may inform the policy development phase of the Docket, summarizing results of the Technical Analysis and implications across evaluation criteria. In addition, E3 provides an overview of commonalities across scenarios that may inform next steps, as well as outstanding technical questions and study needs that E3 identified over the course of the Technical Analysis process.

Summary of Technical Analysis Results

E3 modeled six decarbonization scenarios that present different options for reducing emissions from the gas system in Rhode Island. Each scenario allows the state to meet the emissions reductions mandate of the Act on Climate. The Technical Analysis results are summarized through 5 critical outputs: emissions, technology adoption, energy demand, gas system impacts and electric system impacts.

Emissions

The analysis shows that existing policies and trends, represented in a reference scenario, achieve 40% emissions reductions by 2030 compared to 1990 levels, which means that additional mitigation measures are required to achieve the Act on Climate. While reference scenario emissions reductions are largely driven by reductions in the electricity sector, the modeled decarbonization scenarios include accelerated measures in the Transportation and Buildings sector to comply with the Act. Under Rhode Island's GHG accounting framework, all decarbonization scenario modeled by E3 achieve the Act on Climate targets of 45% by 2030, 80% by 2040 and net zero by 2050, compared to 1990 levels. While the level of emissions reductions is identical across scenarios, emission reductions are achieved through distinct measures in the heating sector, with primary variations in building and industrial applications. Sensitivity analysis demonstrates that scenarios with higher levels of renewable fuels may have higher remaining emissions under alternative accounting assumptions. In addition, sensitivity analysis shows that a delayed achievement of the Advanced Clean Cars II and Advanced Clean Trucks rules in Rhode Island would require deeper and more accelerated measures primarily in buildings, with implications for the role and use of the gas system.

Technology Adoption

Although the six decarbonization scenarios achieve the Act on Climate through a distinct mix of technology adoption in the residential and commercial sector, the Technical Analysis demonstrates that energy efficiency and building electrification are a critical component of gas system decarbonization. Scenarios focused on higher levels of electrification, such as High Electrification, Staged Electrification, Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup, require residential heat pump adoption levels by 2030 and 2040 that are nearly 10 times higher than today's

adoption levels. Scenarios that rely more heavily on renewable fuels to achieve the Act still include a five times increase in heat pump adoption compared to today. There are significant cost barriers associated with these levels of heat pump adoption that were not modeled in the Technical Analysis through consumer or economic behavior. Achieving the adoption levels as modeled in the Technical Analysis that are needed to comply with the Act's goals therefore likely requires policy intervention. In the industrial sector, all scenarios include significant levels of efficiency and varying levels of industrial electrification. Industries that are harder to decarbonize, such as the chemical and metals-based industry as well other manufacturing processes using high temperature heat, leave a role for pipeline gas and see increased adoption of dedicated hydrogen.

Energy Demand

All scenarios see transformational changes in the way Rhode Island uses energy; across scenarios, final energy demand decreases between 40-50% by 2050, primarily as a result of efficiency and electrification. In addition, Rhode Island will see increased use of renewable fuels, through the Biodiesel Heating Act in the near term and to comply with emissions targets in the long term. By 2050, between 50-70% of the fuel mix across scenarios consists of renewable fuels, with the largest reliance in the Continued Use of Gas scenario. Gas throughput in Rhode Island declines in all scenarios: By 2050, gas throughput is reduced by 45% in the Continued use of Gas scenario and between 80-95% in all other scenarios as a result of efficiency and electrification.

Gas System Impacts

All scenarios imply a transformation in the role and use of the gas system in the next decades. While gas throughput and the number of customers connected to the gas system decline, the costs of the system under the currently regulatory framework are expected to rise. Planned levels of capital expenditures through the ISR program cause the annual gas revenue requirement to nearly double towards 2050, with variations across scenarios in the number of new gas connections assumed. Scenarios that do not assume additional customer connections (High Electrification, Hybrid with Delivered Fuels Backup, Staged Electrification) reduce annual costs by nearly 20% by 2050 compared to a reference scenario.

A managed transition that would include targeted deployment of non-GHG emitting heating technologies that minimize or avoid gas system investments, could significantly reduce the costs of the gas system. Using an illustrative assumption of a maximum of 50% avoided capital replacements through targeted electrification, a managed transition could reduce the costs of the gas system by up to 35% in scenarios that transition away from the gas system in the near term (High Electrification, Hybrid with Delivered Fuels, Staged Electrification). However, the level of coordination required for a managed transition is unprecedented and more research is needed to understand the technical feasibility of this approach.

Under the current regulatory framework, decarbonization scenarios that assume a high level of customer departures through electrification lead to untenable long-term gas delivery rates by recovering the costs of the gas system over fewer and fewer customers. Although a managed transition can save gas system costs on the system, these cost savings only partly mitigate the effect on long-term customer rates. Assuming customers are not able to bear the costs of the system in

scenarios with high levels of customer departures, the gas distribution system is faced with a potentially total unrecovered rate base in 2050 of 2.6B (unmanaged). If RIE could avoid up to 50% of capital replacements in the next decades, the size of the rate base could be reduced to \$1.5B.

Electric System Impacts

By 2050 across scenarios, 40-60% of final energy demand is served by electricity. Scenarios with high levels of electrification see nearly doubling of annual load by 2050 compared to today's levels. Scenarios with high adoption of heat pumps cause the Rhode Island electricity system to become winter peaking in the 2030s. In the High Electrification scenario, the adoption of ASHPs leads to median peak demand by 2050 of approximately 3.5 GW, nearly double the size of the system compared to today. This peak demand is mitigated by load flexibility (e.g. flexible vehicle charging), demand response, and smart devices (e.g. smart thermostats and lighting timers). These electric peaks can further mitigated by approximately 1 GW through the use of hybrid backup systems or the use of highly efficient electric heating systems, such as networked geothermal.

Renewables become a major source of generation in the New England and Rhode Island electricity portfolio. Total cost of electric service increases across all scenarios driven by higher electric demand and higher cost of electric generation to meet the 100% RES and similar requirements throughout the region. However, despite the costs of the electric system nearly doubling in scenarios with high levels of electrification, the costs of service increases are largely offset by increased loads, especially for scenarios with high load factors.

Scenario Implications

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges across multiple evaluation criteria. Key implications are summarized below.

- + Economy-wide costs vary from \$14B to \$26B NPV (2023-2050) across scenarios and cost sensitivities.** Across scenarios, the cumulative incremental total resource costs vary from \$14.0B to \$17.6B with low-bound cost parameters and \$19.0B to \$25.9B with high-bound cost parameters (NPV, 2023-2050). Scenarios with high reliance on renewable fuels, such as the Continued use of Gas scenario, and scenarios with higher levels of networked geothermal systems, such as Alternative Heat Infrastructure, see higher levels of cost risks. The scenarios that rely more heavily on hybrid solutions, such as Hybrid with Gas Backup and Hybrid with Delivered Fuels Backup, show lowest levels of cost across all sensitivity parameters. Staged Electrification also shows low levels of cost risk across the test sensitivities.
 - **A managed transition could help reduce total resource costs in Rhode Island, but the extent to which costs can be avoided is highly uncertain.** Based on an illustrative assumption of 50% capital expenditure avoidance on the gas system, the High Electrification and Hybrid with Delivered Fuels Backup scenarios both reduce total resource costs by \$1.7B NPV relative to the modeled unmanaged transition.
- + Customer choice is a key consideration in scenarios assuming a managed transition.** Scenarios that are able to avoid capital reinvestments on the gas system through targeted

electrification assume that coordinated level of planning is possible with 100% opt-in from customers. Under these assumptions, the High Electrification and Hybrid with Delivered Fuels Backup scenarios require up to 3,000 customers per year to opt-in on voluntarily replacing their source of heating on a neighborhood-by-neighborhood basis. Implementing such projects is likely more complicated because of economics and other factors that influence customer choice. These considerations need to be addressed in the policy development phase of this Docket.

- + **Energy affordability is a concern today and continues to be a challenge across all scenarios but for different reasons.** Under today's rates, customers using gas as their primary source of heating that adopt all-electric heating appliances experience approximately an increase of 25% in monthly energy bills. In addition, those customers are faced with significant upfront costs for electric appliances. At the same time, if customers exit the gas system as a result of electrification, the relative affordability of electrification improves as delivery costs of gas rise. Under the current regulatory framework, this poses a significant cost shift risk towards customers that are less likely to be able to afford electrification measures. Absent policy or regulatory changes, customers that remain on the gas system in the long term risk a significant increase in energy burden.
- + **Air quality improves in all scenarios relative to today, especially in scenarios with higher levels of electrification.** Across the scenarios as modeled, fuel combustion declines by 65-85% in all scenarios as a result of high levels of efficiency and electrification. The overall decline in combustion across scenarios implies that complying with the Act on Climate has an overall positive impact on air quality and ultimately, health in the state of Rhode Island. All else equal, scenarios with higher levels of electrification are likely to see more air quality benefits than scenarios that leave higher levels of fuel combustion. A more detailed, quantitative analysis can help to further investigate the magnitude of these potential benefits.
- + **Rhode Island will likely see an increase in clean energy workforce opportunities.** The level of adoption of clean energy technologies required to achieve the Act is unprecedented and far exceeds the level of adoption of clean energy technologies deployed today. Given that many technology installations need to happen in state, especially those related to the building sector, Rhode Island is likely to see an increased need for skilled workers. At the same time, four out of six scenarios may have a negative impact on the workforce in the gas sector, but those impacts are likely to occur only in the long term.
- + **Reliance on out of region fuel supply will be higher in scenarios with lower levels of electrification.** Rhode Island likely needs to rely on out-of-region capital investments in and production of renewable fuels to meet the Act on Climate. Therefore, scenarios with higher levels of renewable fuels to serve heating demand are more likely to continue to rely on out-of-region resources in contrast to scenarios with higher levels of electrification that transition more strongly to in-region supply of energy for heating purposes. Although the in-region supply of electricity leads to constraints with regard to electric system expansion, this trend also leads to higher levels of local economic opportunities and reduced dependency on fluctuating market dynamics associated with fuels.
- + **Technology readiness or state of commercialization is lower for advanced renewable fuels, networked geothermal systems and use of dedicated hydrogen in industry.**

Portfolios of decarbonization options that rely on lower technology readiness levels (TRL) measures carry additional risk over scenarios that rely on commercialized technologies. These risks are most prominent in the Continued Use of Gas scenario and Alternative Heat Infrastructure scenario, that rely on renewable fuels and networked geothermal systems respectively in order to meet Rhode Island's emissions targets.

- + **Pace of electric system expansion is unprecedented across all scenarios, but is most pronounced in the High Electrification scenario.** All scenarios require significant renewable buildouts to comply with 100% RES. To serve increasing loads and meet rising peak demand from electrification, renewable generation and T&D infrastructure needs to be significantly expanded. The impact is especially pronounced in the High Electrification scenario which leads to a +/- 1 GW increase in required electric system capacity in the next decade.

Commonalities Across Scenarios

Despite differences across scenarios in the transformation of the heating sector and associated use and role of the gas system, E3 distills several key commonalities across scenarios that are essential to achieving near-term climate targets in the state. These commonalities may help inform the Policy Development phase of the Docket.

- + **Energy efficiency.** To achieve the Act, all scenarios rely on significant energy efficiency measures, such as building shell retrofits, efficient industrial technologies, efficient appliance sales, efficient lighting, smart devices such as programmable thermostats, and managed electric vehicle charging, that far exceed the state's rate of adoption today.
- + **Building electrification.** Building electrification is a significant component of gas system decarbonization across scenarios. Heat pump adoption levels in the next decade are 5-10 times higher than today's level of adoption.
- + **Renewable energy generation and electric system expansion.** Achieving the 100% RES in combination with significant levels of electrification in all scenarios requires expansion of the electric grid. Rhode Island's electric system today experiences constraints that need to be addressed in order for the system to be able to handle the increase in loads and peaks expected to comply with the Act.
- + **Affordability issues with decarbonization scenarios.** All scenarios rely heavily on decarbonization measures that increase costs from a customer perspective, both in terms of upfront and operational costs. The adoption of decarbonization measures at the scale required to achieve the Act implies the need for policy development to mitigate these costs.
- + **Long-term impact on gas customer bills.** All scenarios lead to an increase in rates for customers on the gas system, either through the effect of customer departures, or through the increase in gas commodity costs as a result of renewable fuel procurement. These results point out an important area of focus for the policy development phase of the proceeding.
- + **Opportunities for electrification of delivered fuels.** Although the focus of the Docket is on the implications of the Act on the gas distribution system, the Technical Analysis assessed the required transformations across the entire state, including the western half of Rhode

Island that primarily relies on delivered fuels today. All scenarios assume that delivered fuels customers adopt electric heating appliances. In contrast to gas customers, customers currently using delivered fuels for the main source of heating that adoption electric heating solutions see a decrease in monthly energy bills, which implies a significant near-term opportunity for emissions reductions.

- + **Significant uncertainty related to renewable fuels.** All scenarios include a role for renewable fuels such as green hydrogen, renewable diesel in transportation, and renewable natural gas. As noted throughout this report, there is significant uncertainty associated with the availability and cost of renewable fuels, as well as the emissions impact of fuels under different accounting mechanisms. As all scenarios rely on renewable fuels to some extent, at minimum to comply with the Biodiesel Heating Act, there is an increasing need for ways to mitigate uncertainty that can be addressed in the policy development phase of the Docket.

Outstanding Technical Questions And Study Needs

The Technical Analysis raises key outstanding questions on the implementation and technical feasibility associated with decarbonizing the gas system. E3 identified two primary outstanding technical feasibility questions that require further study.

Technical Feasibility Related to a Managed Transition

As noted throughout this report, the assumptions E3 used to estimate the impact of avoided gas system costs are illustrative and not based on empirical evidence or data inputs from RIE. The order of magnitude of gas system cost avoidance assumed in this study is unprecedented, despite early pilots throughout the United States and beyond that have started to investigate the opportunity associated with targeted electrification. E3 distills three important research questions for further study that were beyond the scope of the Technical Analysis:

- + ***What parts of RIE's system can be classified as "hydraulically feasible", i.e. can potentially be decommissioned while maintaining the gas flow, minimum allowable pressure and secondary feeds required to ensure safe and reliable service of other parts of the gas system?*** The Technical Analysis does not model the performance and operations of the gas system, nor does it provide a geographical representation of cost avoidance opportunities. Additional study by RIE is necessary to understand the magnitude of opportunity associated with targeted decommissioning.
- + ***What parts of the gas system, if any, are cost-effective to electrify through targeted decommissioning?*** Other studies have identified the cost-effectiveness of targeted electrification through neighborhood-specific study of key parameters, such as system density, pipeline age, replacement costs, cost of electrification, etc.¹²² This type of study is

¹²² See, for example: E3 - [Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California](#); Groundwork Data - [Equitable Energy Transition Planning in Holyoke Massachusetts - A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency](#).

necessary in Rhode Island to better understand the feasibility and opportunity associated with targeted electrification.

- + ***What additional costs, if any, are associated with decommissioning of the gas system that are not yet captured in the current accounting of asset removal costs recovered by RIE in the annual revenue requirement?*** In E3's modeling framework, it is assumed that pipeline decommissioning and removal costs are already accounted for in the company's annual revenue requirement. Since the scale of decommissioning that is required in some scenarios is unprecedented, these assumptions require additional investigation.

Other implications associated with a managed transition, such as questions related to customer choice and the implications for different customer classes, require specific policy and regulatory intervention and are therefore to be addressed in the Policy Development phase of the Docket.

Technical Feasibility Related to Networked Geothermal Systems

Although networked geothermal systems have been installed in a handful of settings, such as campuses, and pilots in New England are underway that test the feasibility of the systems, additional study is required to understand the potential and technical feasibility of the scale of networked geothermal systems envisioned in the Alternative Heat Infrastructure scenario. Based on best available information today, networked geothermal systems have the potential to significantly reduce electric peak system impacts due to their highly efficient nature, but the systems also require substantial capital investments. The scale of the systems required in the Alternative Heat Infrastructure scenario implies a conversion of a large number of buildings at the same time. Additional research is required to understand the geological feasibility of these systems across the state, as well as to identify parts of the state where networked geothermal systems can provide the highest level of benefit.

Technical Feasibility Related to Delivered Fuel Backup Systems

The Hybrid with Delivered Fuels backup scenario demonstrates benefits with regard to electric peak mitigation while at the same time allowing for targeted electrification projects that may avoid gas system costs. However, the concept of using delivered fuels as a backup for winter heating needs, especially for customers currently connected to the gas system, is novel and requires further study. For example, it is unclear to what extent existing gas furnaces or boilers can be converted to propane systems with minimal adjustments, as explored through sensitivity analysis in this report. In addition, more insights are needed to understand if conversion to delivered fuels supply is a practical solution for customers in RIE's territory, given the tank storage required on customer premises. Lastly, E3 did not estimate any emissions impact from the in-state fuel delivery supply chain, such as increased truck movements that may occur as more customers transition away from networked gas towards delivered fuels.

Workforce Impacts

A detailed study investigating the impacts of the Act on Climate on the workforce in Rhode Island, both related to the gas distribution system and to the broader clean energy transition, was beyond the scope of the Technical Analysis. At the same time, as shown in this study through qualitative

research, Rhode Island is likely to see an increase in clean energy workforce opportunities and the need for skilled workers, while the need for skilled workers on the gas distribution system may evolve in the long term. Additional investigation into the jobs and skills necessary to facilitate the transformations outlined in this study is necessary to understand the challenges, opportunities and potential gaps associated with Rhode Island's workforce as the state transitions to a net zero economy.