78

Maine Pathways to 2040:
Analysis and Insights

PREPARED BY

Dean Murphy
J. Michael Hagerty
Goksin Kavlak
Noah Rauschkolb
The Brattle Group

Gabe Kwok
Ryan Jones
Evolved Energy Research

PREPARED FOR

Maine Governor's Energy Office

JANUARY 2025

Brattle

EVOLVED ENERGY RESEARCH

AUTHORS AT THE BRATTLE GROUP

Dean Murphy is an economist with over thirty years of experience, a background in engineering and expertise in energy systems and their transformation in response to climate change. His work, initially centered in the electric industry, has broadened to include decarbonization of other energy sectors – heating, transportation, and industrial energy use, and particularly the natural gas sector. He has performed a number of medium- and long-term energy planning and forecasting studies that examine the transition to decarbonized energy in the heating and electricity sectors. He also has experience in renewable solicitations, resource and investment planning, and nuclear economics.

Dean.Murphy@brattle.com

Michael Hagerty is an energy economist with ten years of experience in the power industry. His consulting work is focused on analyzing renewable energy and climate policies, transportation and heating electrification, wholesale market design, and electric system infrastructure needs.

Michael.Hagerty@brattle.com

Goksin Kavlak specializes in electricity sector topics such as transportation and building electrification in states with ambitious decarbonization goals, rate design for emerging end-uses such as electric vehicle charging, and energy affordability. She earned her Ph.D. in Engineering Systems from the Massachusetts Institute of Technology.

Goksin.Kavlak@brattle.com

Noah Rauschkolb is an energy systems engineer specializing in demand-side solutions to decarbonization, including building electrification, distributed energy resources (DERs), and load flexibility. He holds a Ph.D. in Mechanical Engineering from Columbia University.

Noah.Rauschkolb@brattle.com

AUTHORS AT EVOLVED ENERGY RESEARCH

Gabe Kwok has expertise in energy planning, wholesale electricity markets, and economic analysis. His work supports the policy, planning and investment decision-making needs of clients across all sectors, including regulators, utilities, project developers, investors and non-governmental organizations.

gabe.kwok@evolved.energy

Ryan Jones co-founded Evolved Energy Research, a consultancy dedicated to the study of energy systems and the steps involved in reducing greenhouse gas emissions. Through this work, creating and using a broad set of analytical tools, he has developed a unique understanding of the long-term challenges and opportunities facing the energy sector.

ryan.jones@evolved.energy

NOTICE

- This report was prepared by The Brattle Group and Evolved Energy Research for the Maine Governor's Energy Office (GEO). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's or Evolved Energy Research's clients or other consultants.

- The study team is grateful for the valuable contributions made by the GEO staff and Brattle team members including Energy Specialist Sylvia Tang and Research Associate Sasha Kuzura. The study team also thanks David Plumb of Consensus Building Institute for facilitating the stakeholder process, and the many stakeholders who participated in the process through stakeholder meetings and listening sessions, and providing valuable comments.

TABLE OF CONTENTS

Executive Summary

The Maine Governor's Energy Office (GEO) has commissioned The Brattle Group and Evolved Energy Research (EER) to develop this report to inform an updated State Energy Plan that will ensure affordable, reliable, and clean energy that supports the growth of Maine's economy while meeting greenhouse gas (GHG) emissions reduction requirements and supporting communities across Maine. Building on a number of previous initiatives and studies conducted by the GEO and other state agencies, this report offers recommendations related to renewable generation, electric transmission, end-use electrification, clean fuel use, and load flexibility.

The report is structured around a **pathways analysis** that identifies alternative pathways by which Maine might meet its clean energy and climate goals. Those goals include reducing the dependence on oil in the state, utilizing 80% renewable electricity by 2030, procuring 100% clean electricity by 2040, and achieving carbon neutrality by 2045, all in a cost-effective manner as articulated by the state's climate action plan, *Maine Won't Wait*. This report integrates the latest data and analyses on renewable energy technologies and markets, end use equipment, and GHG emissions accounting, leveraging valuable feedback from key stakeholder groups and the broader public.

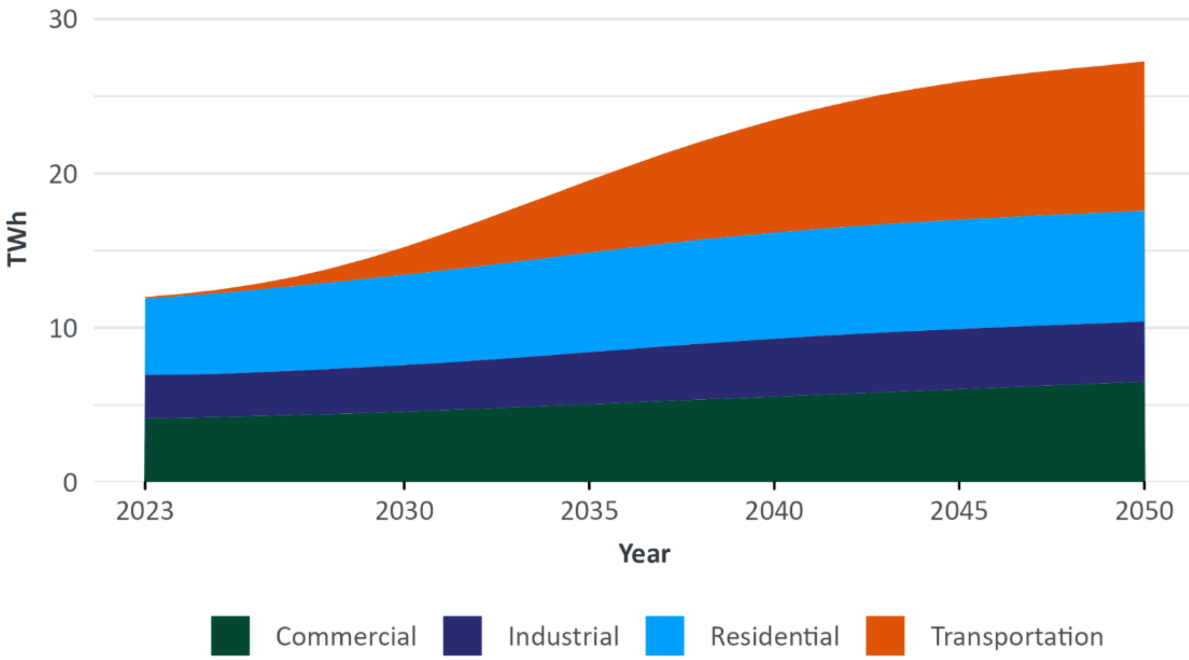
This study characterizes a stylized "Core" pathway and several alternative pathways by which Maine could decarbonize its economy. The goal is not to choose from among these pathways, but rather to compare and contrast them to learn about the relative advantages and costs of alternative ways to meet Maine's clean energy goals. Pathways are simulated with a framework that models key energy uses across sectors, producing detailed year-by-year forecasts of hourly end-use energy demand, and identifies the investment and operational decisions that yield the lowest cost way to meet this demand, while achieving the state's clean energy goals.

KEY RESULTS

Widespread Electrification of Transportation and Heating.

Electrifying end uses that currently rely on fossil fuels is a key strategy for achieving Maine's clean energy and climate goals. Consistent with Maine's Climate Action Plan *Maine Won't Wait*, over the coming decades most furnaces and boilers will need to be replaced over time with efficient electric heat pumps. Similarly, the number of light-duty electric vehicles

FIGURE ES-1: ELECTRICITY CONSUMPTION IN MAINE BY SECTOR, CORE PATHWAY



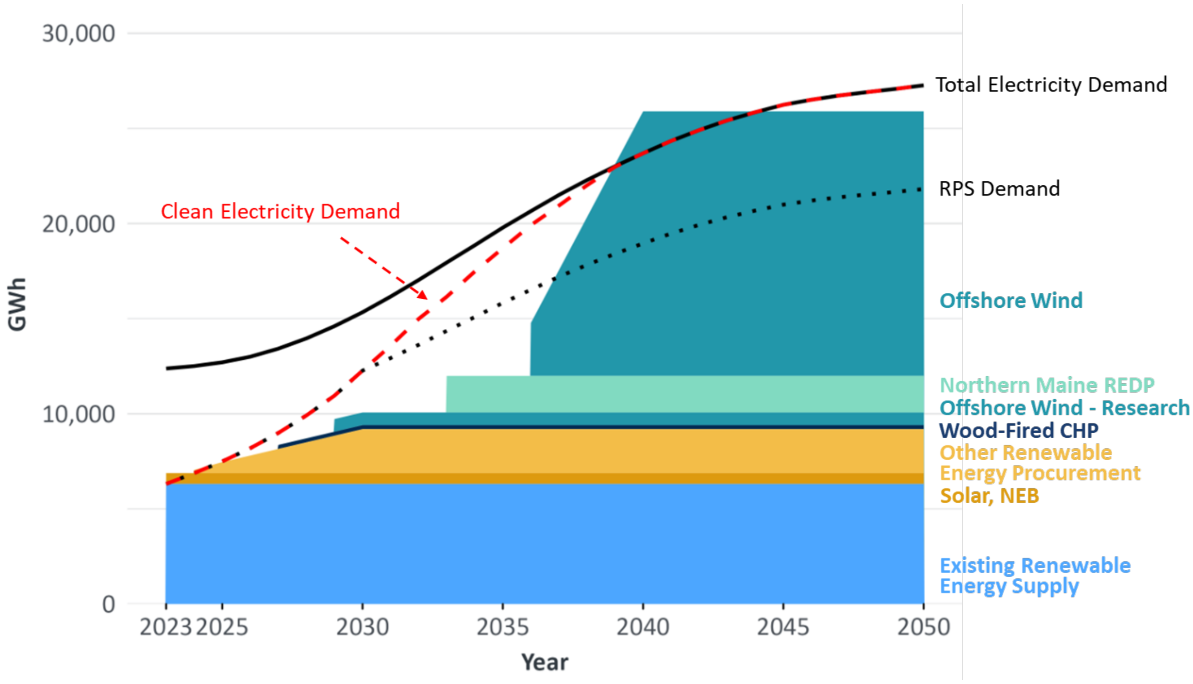
must grow considerably by 2040. Non-light-duty vehicles such as buses and trucks must undergo a transition as well, albeit occurring mostly in the latter years of the study period. These changes in end use are the primary driver of increases in electricity sales, which are forecasted to more than double from 2023 to 2050 in the Core pathway (Figure ES-1). Energy efficiency improvements, including from building envelope retrofits, are deployed in all scenarios to help manage load growth from electrification.

Changing Electricity Supply to Meet 100% Clean Electricity in 2040.

As the electrification of transportation and buildings progresses, raising electricity demand, it will be essential to decarbonize the electricity supply. Maine is already taking steps to add clean electricity resources through its commitments to offshore wind, the Northern Maine Renewable Energy Development Program, and other renewable energy procurement (Figure ES-2). This study finds that Maine's new planned and contracted resources, on top of the renewable resources it is currently utilizing, will meet most of Maine's clean electricity needs by 2040. However, certain additional clean and renewable resources are likely to be needed.

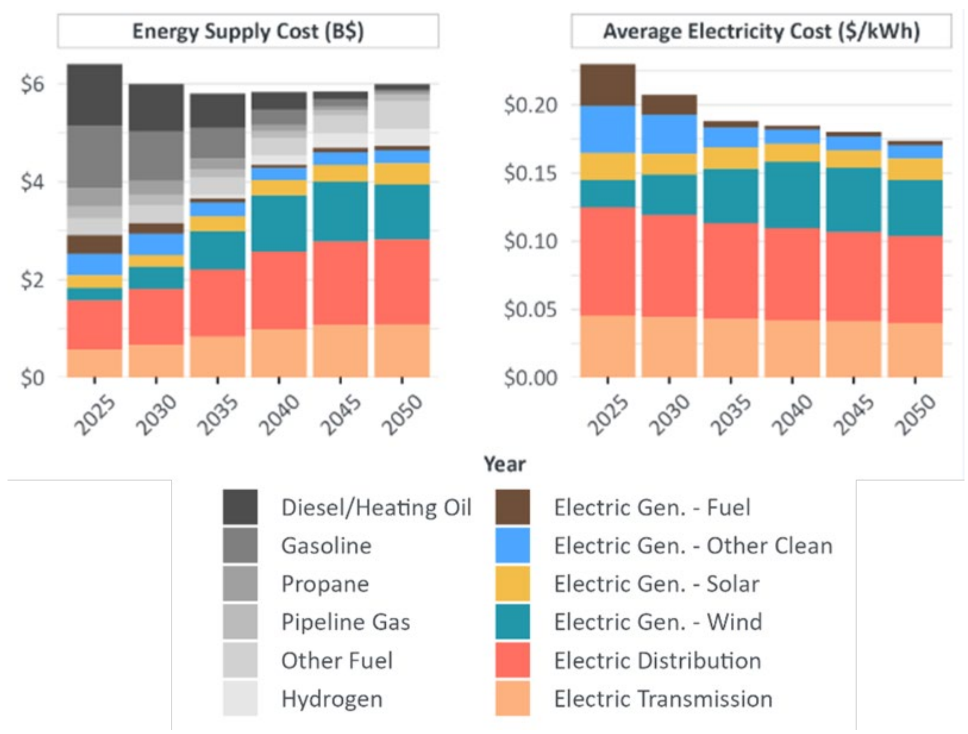
Because most of Maine is within the New England electricity grid operated by the ISO New England (ISO-NE), most of the electricity consumed in Maine may be generated anywhere across the ISO-NE grid or imported from other jurisdictions beyond; this is true for all New England states. To ensure adequate supply of clean energy, balance output from variable renewables, and meet increasing overall load, Maine will need to expand its transmission system, bolstering capacity on existing transmission lines, utilizing grid enhancing technologies, and adding new lines to connect new resources. This will enable greater exchanges with neighboring states and regions, and moving more power across the grid, with the goal of increasing reliability and decreasing overall system costs. Lower-voltage transmission and distribution infrastructure will also need to be upgraded to manage greater loads. Even with the benefits of inter-state load balancing, thermal generation resources will continue to play an important role, providing reliability at times of high demand or during periods with a shortage of renewable generation.

FIGURE ES-2: MAINE'S CLEAN ELECTRICITY DEMAND AND PLANNED/CONTRACTED RESOURCES



Notes: Existing renewable energy resources representing Maine's current RPS compliance (51%) are assumed to continue to be available in the same quantities going forward to illustrate how incremental planned resources compare to incremental clean energy requirements.

FIGURE ES-3: ENERGY SUPPLY COSTS AND AVERAGE SOCIETAL ELECTRICITY COST FOR MAINE (2022$)



Note: See notes at Figure III-13.

Energy Supply Costs.

Overall energy supply costs are unlikely to increase significantly and may decrease somewhat over time (Figure ES-3). While overall expenditures on electric generation, transmission, and distribution will increase to serve higher demand from electrified end uses, these higher electricity costs are largely offset by savings from decreased reliance on costly fossil fuels. The average cost of delivered electricity will likely fall over time, since sales volumes will increase slightly faster than costs.

KEY OBSERVATIONS FROM ALTERNATIVE PATHWAYS.

In addition to the "Core" pathway, which assesses a likely high-electrification path for a statewide clean energy transition, the analysis includes five additional pathways designed to answer specific questions and assess the impact of known uncertainties. Key observations from these pathways include:

- **A policy requiring that all electricity be renewable[1] by 2040** and therefore mandating retirement of thermal electricity generators (as opposed to allowing thermal generators if they burn clean fuels) would raise energy supply costs, as it would be necessary to build even more renewable generation and long-duration energy storage in order to maintain system reliability.
- Maintaining some furnaces and boilers to provide supplemental heating in extreme cold, alongside widespread heat pump adoption, in a Hybrid Heat pathway, could lower certain long-run electricity costs by reducing the winter electricity system peaks. However, the need to replace, maintain, and fuel these systems with clean, low-carbon fuels in order to meet emission reduction goals would offset much of the electricity cost savings. Furthermore, ensuring effective controls that enable consumers to benefit from, and thus participate in, such a strategy would require considerable innovation.
- **Unlocking the flexibility of electric vehicle charging loads and other flexible loads could substantially decrease electricity supply, transmission and distribution costs.** The ability to shift flexible loads to periods with relatively more abundant electricity supply and less demand can significantly reduce the infrastructure requirements and therefore the costs related to transmission and distribution (T&D) infrastructure and supply resources. This would require system operators to communicate current and projected system conditions, and relies on the ability and willingness of consumers to respond with a substantial amount of flexible end use load. Conversely, failing to employ load flexibility would necessitate significantly more electricity supply, transmission and distribution infrastructure in order to maintain reliability, resulting in higher costs for consumers.
- **Increasing the adoption of distributed energy resources (DERs)** would reduce upstream electricity supply costs. However, if additional DERs are deployed uniformly across the system, these **savings may be outweighed by the cost of the DERs themselves**. It would likely be more cost-effective to target DER adoption in locations where they are most valuable for reducing electricity infrastructure requirements and costs, particularly where they can avoid or limit distribution system upgrades.

[1] Maine's RPS regulations define Class I/IA renewable resources to include solar, wind, geothermal, tidal power, fuel cells, hydroelectric generators that meet all state and federal fish passage requirements, and biomass generators, including generators fueled by wood products and landfill gas. 35-A M.R.S. §3210. Renewable Resources.

SUPPLY-SIDE POLICY IMPLICATIONS

- **Maine Must Follow Through on its Procurement Commitments for Clean Energy to Meet its 2040 Goals.** To achieve 100% clean electricity by 2040, Maine must accelerate its procurement of renewable energy, increasing its renewable purchases from 6,000 GWh annually now (51% of current annual demand) to about 24,000 GWh per year. This growth is essential to displace fossil fuel-based electricity generation and simultaneously meet rising electricity demand from electrification of heating and transportation, and it continues beyond 2040. Maine is making strides with its commitments to offshore wind projects, the Northern Maine Renewable Energy Development Program, and additional solar initiatives, and must follow through on those commitments. Maine must also clearly define which energy resources qualify as *clean* (beyond the suite of renewable technologies currently eligible for the state's Renewable Portfolio Standard) to ensure it can plan, develop, and maintain these resources in an orderly way to meet the 2040 target. Continued progress will require coordinating with neighboring states and regional entities. Maine will also need to address the medium-term gap between clean electricity demand and planned resources.
- **Thermal Electricity Generation with Clean Fuel Facilitates High Renewable Penetration.** Maine's goal of 100% clean electricity by 2040 will likely be achieved most cost-effectively if it incorporates zero-carbon dispatchable thermal generation. While it would be possible to achieve the goal without thermal electricity generation, this would be more difficult and costly, requiring very large amounts of long-duration energy storage (LDES) and additional renewable generation to charge it. A practical and cost-effective approach will rely on a similar amount of dispatchable thermal generating capacity as is currently available, but operating it sparingly using carbon-neutral fuels during periods of unusually low renewable output and/or high demand. While it will take time to build up the capacity to produce these fuels, they will likely be provided at least in part through a larger national supply chain that also serves the transportation and industrial sectors. Existing gas-fired generators adapted to these fuels likely could meet this need, and some additional thermal capacity may be needed in New England to cover higher peak loads driven by electrification. Even with backup thermal generation, renewable resources are still expected to provide 80% or more of Maine's electricity supply after 2030 and 85% of New England's supply by 2050. The remainder would be served by existing nuclear plants (about 10%) and a small amount of thermal electricity generation with clean fuels (less than 5%). It will be important to understand the extent to which these clean fuels are actually low/zero-carbon, according to lifecycle analyses that account for emissions during production, transportation, and use. Any residual non-zero GHG emissions associated with "clean" fuels could be mitigated or offset to support Maine's 100% clean electricity goal.
- **Policymakers Must Continue to Modernize Transmission and Distribution Planning to Facilitate Clean Energy Goals.** Maine's clean energy transition (and that of other New England states) will require more efficient use of the existing system and significant expansion of the regional electric power system, including transmission and distribution infrastructure. This expansion is driven by increased peak electricity demand and the location and type of new (largely renewable) generation resources. Delays in developing this grid infrastructure could limit access to low-cost generation, delay clean energy development, slow the adoption of electrified heating and transportation, and cause reliability issues. Policymakers and grid planners in Maine must collaborate with each other and with other

entities across the region on proactive planning processes to ensure timely and cost-effective upgrades and expansion to achieve Maine's clean electricity goals.

- **Ensure that Fuels Become Cleaner with Time.** Since not all fuel use is likely to be eliminated, it will be important to ensure that remaining fuels are as clean as possible. This can be achieved by blending an increasing share of clean fuels into fossil fuels, to ensure emissions fall even as some fuel use persists. For example, Rhode Island requires biodiesel blending with heating oil, reaching 50% by 2030; Connecticut and Massachusetts have similar mandates, and California's Low-Carbon Fuel Standard has reduced diesel emissions by blending renewable diesel. Linking a blending requirement to overall fuel use could effectively place a declining cap on fossil fuel use, ensuring emissions targets are met regardless of the pace of electrification.

DEMAND-SIDE POLICY IMPLICATIONS

- **Electrifying Transportation is Key to Cost Effective GHG Reductions and Electricity Grid Investment.** Electrifying transportation is essential for meeting Maine's clean energy and GHG reduction goals, as the transportation sector accounted for 49% of the state's GHG emissions in 2019. Electric vehicle (EVs) will lead to significant fuel cost savings and will help integrate intermittent renewable energy and manage electric grid expansion by providing flexible load management. EV adoption can be facilitated with incentives like purchase rebates and efforts to improve public familiarity with EVs. Expanding access to high-speed charging stations, especially in rural areas, will reduce barriers to EV ownership and enhance public awareness, while also enabling load flexibility to support a decarbonized energy system.

- **Maximize Benefits from Heat Pumps While Managing System Peaks Through Flexibility.** Heat pumps provide cost savings as well as an opportunity to reduce GHG emissions by using clean electricity for heating instead of fossil fuels. Maine is leading the nation in heating electrification; it surpassed its 2025 goal of 100,000 heat pumps ahead of schedule and has increased the target to 275,000 by 2027. Heat pump adoption is favorable in Maine due to a range of factors including historic reliance on costly heating oil. Retaining some legacy fuel heating systems may help manage increased electric peaks from heat pumps after 2035, but innovation in controls will be required to dispatch these systems efficiently and ensure that overall fuel use is limited. Additionally, capturing available load flexibility from vehicle electrification can help manage infrastructure costs.

- **Load Flexibility is a Cost-Effective Approach to Reducing Peak Loads.** Flexible loads, such as EV charging, can help the electricity system adjust to short-term fluctuations in renewable energy availability from wind and solar. Pathways incorporating within-day load flexibility require less total electricity infrastructure and have lower overall costs compared to pathways without flexible load. While load flexibility alone cannot balance the entire system, it can assist in meeting short-term balancing needs while limiting the need for additional infrastructure. EV charging is particularly valuable for load flexibility due to its substantial magnitude (it is expected to account for about one-third of total electricity demand by 2050) and its inherent flexibility. Maine can support effective load flexibility by implementing EV managed charging programs and exploring other opportunities, such as behind-the-meter storage, virtual power plants, demand response, and time-of-use rates, drawing on the expertise of utilities, automakers, and existing managed charging initiatives.

OVERARCHING TOPICS

- **Consider Equity Impacts.** *Maine Won't Wait*, the state's 2020 climate action plan, identified equity as a core goal, aiming to advance equity through the state's climate response. An important challenge in this regard for Maine's clean energy transition is safeguarding low- to moderate-income (LMI) customers from disproportionate cost increases for energy and energy infrastructure while ensuring equitable benefits from new technologies and programs. The necessary conversions often entail substantial up-front costs, which more than pay off through operational savings but can act as barriers to adoption and impose economic burdens on LMI households. If left unaddressed, these barriers might not only pose challenges for LMI customers, but also limit adoption rates, hindering Maine's overall progress in reducing GHG emissions. With approximately 121,000 customers in Maine qualifying for the Low-Income Assistance Program (LIAP), it is crucial to develop policy mechanisms that alleviate the initial financial strain on LMI customers, facilitating adoption and ensuring equitable access to clean energy solutions. An essential first step is to understand the magnitude and distribution of these effects, investigating the specific challenges faced by LMI customers. Depending on the identified barriers, tailored policy mechanisms can be designed to address these challenges. These might include income-qualified grants, low-cost financing, and information and technical assistance programs to help citizens understand the new technologies, their benefits, and requirements.

- **Address Barriers to Adoption.** While the analyses project the adoption of decarbonization technologies according to specified pathways, barriers to adoption may arise for both customer end-use technologies (heat pumps, EVs, electric water heaters) and supply-side technologies (renewable generation, storage, transmission, carbon-neutral fuels). On the customer side, it is important to acknowledge and address potential barriers such as the high initial cost of new equipment, customer unfamiliarity with new technologies, and simple inertia. On the supply side, streamlining land-use, siting and permitting policies, and processes, will reduce costs and uncertainty caused by delays. If left unresolved, these barriers could limit penetration or slow the pace of the transformation, ultimately delaying the achievement of Maine's goals. To achieve the penetration rates characterized in the pathways, it will be necessary to anticipate these barriers, develop policy approaches, and ensure coordination across entities to help overcome them.

- **Invest in the Workforce Transition.** The energy transition will necessitate a sizable workforce to install and maintain the end-use and supply-side infrastructure needed for Maine's clean energy transformation. If the requisite workforce is not developed, or is not able to perform well, this could become a barrier to implementing the transformation in the timeframe of the state's goals. Maine should create and continue to implement programs offering career advice, training, apprenticeships, and on-the-job training, and coordination with local employers. These can be administered by local colleges and technical and vocational schools, career and training centers, and other workforce development entities.

- **Regional Coordination and Cooperation.** For Maine to achieve its clean energy and GHG reduction goals, regional coordination and cooperation with other states and entities will be necessary on issues including power system generation and transmission investments, power system operations, electric vehicle adoption, and heat pump adoption. Regional coordination on these issues will be essential for managing costs and ensuring reliability, since many of these systems are regional in nature, and because the greater scale of coordinated efforts will be more effective.

I. Introduction and Background

Under Maine law, the Governor's Energy Office (GEO) updates the State Energy Plan for delivery to the Governor and Legislature. The GEO commissioned The Brattle Group and Evolved Energy Research (EER) to develop this report through the *Maine Energy Plan: Pathway to 2040* initiative to inform the development of the updated State Energy Plan.[2]

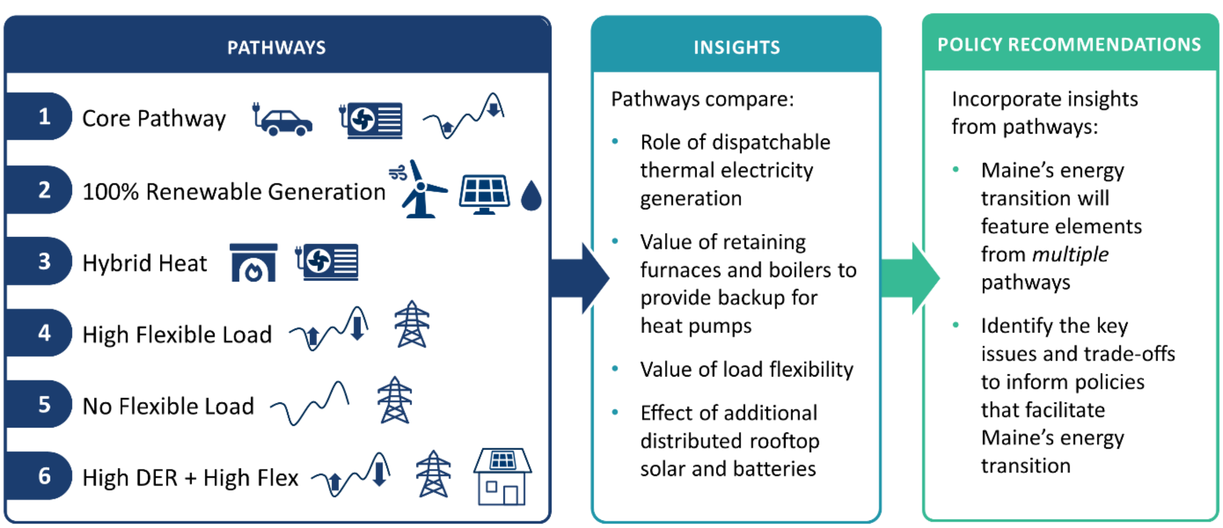
This report develops a detailed technical analysis of alternative pathways for Maine's energy sectors through the coming decades to inform the development of strategies for the state to ensure affordable, reliable and clean energy that supports the growth of Maine's economy and enable achievement of statutory greenhouse gas (GHG) emissions requirements.

What is a Pathway?

Pathways are designed to answer particular questions about the cost and feasibility of mechanisms to decarbonize the energy sector in Maine and New England. The performance of multiple possible pathways is compared across several dimensions, including cost, emissions, and energy use, to identify the factors that may make some pathways more feasible and affordable than others.

Pathways are not designed to establish a set of discrete alternatives, one of which would be chosen as the "optimal" pathway Maine should follow to achieve its greenhouse gas reduction goals. Rather, they are designed to illustrate a number of key issues and trade-offs that will be encountered in decarbonizing Maine's economy, including when those issues are likely to arise and when they need to be addressed, to guide timely and informed policies to support and facilitate the transition (Figure I-1).

FIGURE I-1: PATHWAY ANALYSIS FRAMEWORK USED IN THIS STUDY



[2] State of Maine Governor's Energy Office, "Maine Energy Plan: Pathway to 2040."

Maine's energy policy requirements include reducing the dependence on oil in the state, utilizing 80% renewable electricity by 2030, a goal of 100% clean electricity by 2040, and achieving carbon neutrality by 2045, all in a cost-effective manner. The focus of this report is on the energy sector, which accounts for 91% of greenhouse gas emissions in the state.[3] Non-energy emissions, such as those related to land use, agriculture, and industrial gases, are also important in achieving statutory emissions reduction requirements, but are not the focus of this report.[4]

The pathway modeling considers not just Maine, but also the regional context, given that Maine is part of the regional New England electricity grid and participates in regional and global fuel markets, and because most New England states are pursuing broadly similar emissions reduction goals.

The report offers recommendations that can provide support for policy decisions and guidance for implementation. These recommendations cover measures relating to load flexibility, enabling renewable generation additions through transmission expansions and improvements, and coordinating the transition across sectors to facilitate a decarbonized energy system, among many others. The objective is to identify the policies that will ensure available and cost-effective energy for Maine, facilitate diversifying energy sources, reduce reliance on fossil fuels for electricity generation, heating, and transportation, while mitigating the energy cost burden and supporting historically disadvantaged and low-income communities across Maine.

This report builds on a number of previous initiatives and studies conducted by the GEO and other state agencies. The pathway analysis incorporates Maine's GHG reduction and clean energy goals as prescribed by statute and as articulated in the state's climate action plan, *Maine Won't Wait*,[5] as well as the Governor's directive to achieve 100% clean electricity by 2040.[6] It takes into consideration the best available data and recent analyses on topics such as renewable energy technologies and markets, end use equipment, and GHG emissions accounting, incorporating updated data and assumptions based on recent experience. This report also leverages feedback from key stakeholder groups and the broader public, as described in more detail in the following section.

This report is organized as follows:

- **Chapter 1: Introduction and Background** introduces the study in the context of Maine's clean energy and climate goals, describes the stakeholder engagement process, and provides background on both Maine's long-term goals and its current energy system.
- **Chapter 2: Pathway Modeling Approach** provides a high-level overview of the pathway modeling approach, key characteristics of the modeled pathways, and key modeling assumptions for each pathway.
- **Chapter 3: Pathway Results** describes the results of each pathway with various supporting figures, comparing the results of different pathways.

---

3 Maine Department of Environmental Protection (DEP), "Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals," July 2022.

4 See Maine's Climate Council.

5 Maine Climate Council, "Maine Won't Wait: A Four-Year Plan for Climate Action," December 2020.

6 State of Maine Office of Governor Janet T. Mills, "Governor Mills: Maine Stands on Solid Fiscal Footing, State of the Budget is Strong," February 14, 2023.

- **Chapter 4: Key Policy Implications** outlines the policy implications of the pathways analysis, discussing directions and policies needed to achieve the state's GHG reduction and clean energy requirements, and policy implementation issues.
- **Chapter 5: Conclusion** briefly summarizes the high-level results.
- **Appendices** provide further information on the modeling approach, energy technologies included in the model, and additional detail on the analysis.

A. Stakeholder Engagement

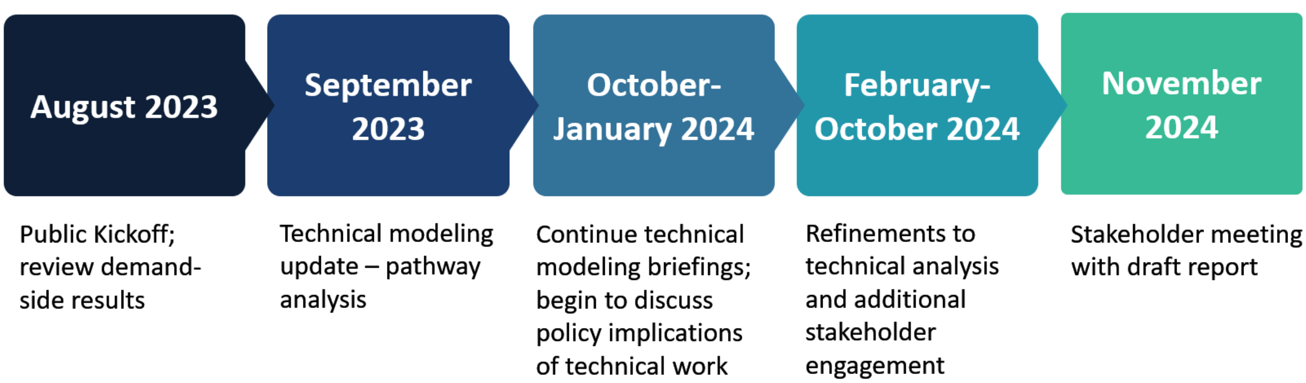
The GEO solicited feedback on the *Maine Energy Plan: Pathway to 2040* process through a series of public meetings as well as meetings with individual stakeholder groups.

As part of this process, the GEO held four virtual public meetings, on August 22, September 28, November 16, 2023, and November 8, 2024 to inform the development of Maine's Energy Plan (Figure I-2). In these meetings, the GEO provided an overview of Maine's Energy Plan and the current progress towards climate and clean energy goals. The Brattle Group and Evolved Energy Research, which led the technical analysis, provided updates on the pathway modeling approach and interim results as the analyses progressed. Consensus Building Institute facilitated the conversations and summarized feedback from previous stakeholder sessions.

The public meetings provided an opportunity for a range of stakeholders to learn about the process and the technical work, receive updates on the most recent results, and provide feedback to guide subsequent direction. Each meeting was attended by 50–150 participants. Participants were invited to ask questions to seek clarifications about the work from the technical team and the GEO, and to provide feedback on the analyses and process, including how to engage more Maine people in the process. Meeting materials and summaries are available on the GEO Maine Energy Plan website.[7]

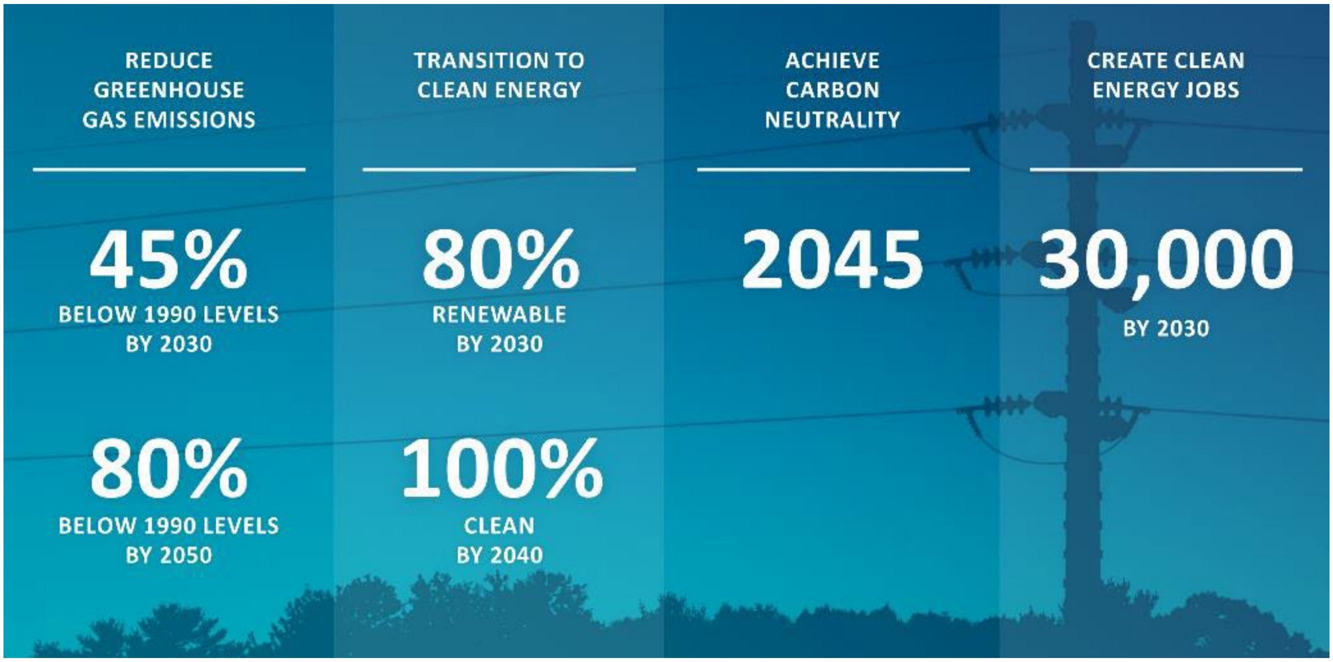
A draft of the report was posted on the GEO website for public comments ahead of the November 8 webinar, which presented a summary of findings from the draft report. Twenty-four written comments were received from stakeholders, including organizations and individuals. These comments were reviewed by the Brattle Group and GEO staff and have been incorporated as appropriate in the final report. The commenters expressed appreciation for the thoroughness and rigor of the report, and provided comments and suggestions on a number of topics,

FIGURE I-2: PUBLIC ENGAGEMENT TIMELINE



[7] State of Maine Governor's Energy Office, "Maine Energy Plan: Pathway to 2040."

FIGURE I-3: MAINE'S CLIMATE AND CLEAN ENERGY GOALS



Sources (left to right): 38 M.R.S. §576-A, 35-A M.R.S. §3210, 38 M.R.S. §576-A, Governor Janet Mills, December 2020.

including clean fuels, distributed energy resources (DERs), equity and affordability, procurements, transmission, load flexibility, energy storage, offshore wind, and energy efficiency. As a result of these comments, modifications were made to the report to clarify assumptions, emphasize certain results, and provide further explanations, consistent with the analyses underlying this report.

In addition to the public meetings, the GEO welcomed the opportunity to meet with individuals, organizations, and businesses in Maine who were interested in understanding and engaging in the development of the Energy Plan. The GEO met and consulted with numerous entities, including other state agencies, quasi-government entities, municipal stakeholders, labor groups, businesses, non-profit organizations, tribes, and youth organizations. Together, this engagement strengthened and informed the underlying assumptions and scenarios included in this report.

B. Maine's Climate and Clean Energy Goals

Maine's overarching climate goals as laid out in *Maine Won't Wait* include reducing Maine's GHG emissions, avoiding the impacts and costs of inaction, fostering economic opportunity and prosperity, and advancing equity through Maine's climate response.[8] While advancing these goals, Maine seeks to bolster its clean energy economy as a whole. Governor Mills aims to reach 30,000 clean energy jobs by 2030 (Figure I-3),[9] which have grown to more than 15,000 in 2022.[10] Recent clean energy legislation such as the

[8] Maine Climate Council, "Maine Won't Wait: A Four-Year Plan for Climate Action," December 2020.

[9] Office of Governor Janet T. Mills, "Energy, Environment, and Climate Change. Protecting Maine's Environment, Advancing Clean Energy & Combatting Climate Change."

[10] Maine Climate Council, "2023 Annual Report, Maine Won't Wait," December 2023.

offshore wind act[11] prioritizes economic development through creating jobs in the manufacturing and installation of cost-effective clean energy technologies and encouraging workforce development, while establishing new supply chains for clean energy businesses. Similarly, the 2019 RPS legislation[12] requires economic benefits in renewable procurements. These efforts represent an invaluable opportunity for transformative investments in Maine communities, supporting rural communities, and delivering economic development in disadvantaged regions of the state.

MAINE'S GREENHOUSE GAS EMISSIONS REDUCTION REQUIREMENTS

In 2019, Governor Janet Mills signed into law GHG emissions reductions requirements of 45% from 1990 levels by 2030, and 80% by 2050 (LD 1679, 38 M.R.S. §576-A[13]). The Governor also has committed the state to *carbon neutrality* by 2045, initially through Executive Order in 2019[14] and subsequently through bipartisan legislation enacted by the legislature in 2021 that went into effect in August 2022.[15] Carbon neutrality, also referred to as net zero carbon emissions, is achieved by balancing anthropogenic emissions of carbon with sequestration of carbon.[16]

The Department of Environmental Protection's (DEP's) biennial report tracks progress toward both of these requirements and documents both gross greenhouse gas emissions since 1990 as well as an estimate of net GHG emissions, which is the gross anthropogenic GHG emissions to the atmosphere (i.e., emissions from human activity) less the total amount of GHG absorbed by the environment.[17]

MAINE'S CLEAN ENERGY REQUIREMENTS

In 2019, the Governor also signed legislation to reform Maine's RPS, increasing the required share of the state's electricity obtained from renewable resources to 80% by 2030 and 100% by 2050 (LD 1494, 35-A M.R.S. §3210[18]). Maine's RPS regulations define renewable resources to include solar, wind, geothermal, tidal power, fuel cells, hydroelectric generators that meet all state and federal fish passage requirements, and biomass generators, including generators fueled by wood products and landfill gas.[19] As of 2022, Maine obtained 48% of the electricity sold in the state from these renewable resources, with hydropower providing more than half

11 L.D. 1895 "An Act Regarding the Procurement of Energy from Offshore Wind Resources;" 35-A M.R.S. §3401–§3410, "The Maine Wind Energy Act."

12 L.D. 1494 "An Act To Reform Maine's Renewable Portfolio Standard;" 35-A M.R.S. §3210. Renewable Resources.

13 L.D. 1679 "An Act To Promote Clean Energy Jobs and To Establish the Maine Climate Council;" 38 M.R.S. §576-A. Greenhouse Gas Emissions Reductions.

14 Executive Order No. 10 FY 10/20: "An Order to Strengthen Maine's Economy and Achieve Carbon Neutrality by 2045," September 23, 2019.

15 L.D. 1429 "An Act to Achieve Carbon Neutrality;" 38 M.R.S. §576-A. Greenhouse Gas Emissions Reductions, 2-A.

16 Maine Department of Environmental Protection (DEP), "Chapter 167: Tracking and Reporting Gross and Net Annual Greenhouse Gas Emissions," 2021.

17 Maine Department of Environmental Protection (DEP), "Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals," July 2022.

18 L.D. 1494 "An Act To Reform Maine's Renewable Portfolio Standard;" 35-A M.R.S. §3210. Renewable Resources.

19 This list pertains to new renewable resources ("Class I/IA"). Maine's RPS requirements also include Class II resources, which include existing renewable resources listed above, as well as efficient cogeneration resources, as defined by 35-A M.R.S. §3210.

of this amount, and biomass, solar, wind, and other resources providing the remainder.[20]

The Governor's directive, as announced in her State of the Budget Address in 2023, expedited the 2050 goal by establishing a *100% clean electricity* target by 2040.[21] The definition of *clean* resources has not yet been precisely specified in Maine, but is likely to be broader than *renewable* resources. The RPS can be an important tool to increase renewable energy resources; however, as the percentage of renewables increases, there are a variety of reliability, cost, and other factors that may support the adoption of broader definition of clean energy. Other jurisdictions (e.g., Massachusetts, California, New York, Colorado)[22] have adopted "Clean Energy Standards" that accept technologies that have zero emissions but may not be renewable. Each state has different requirements, based on resource availability and priorities. Despite the variations in technology eligibility across states, clean resources generally include most renewables plus other resources such as zero- or very-low-carbon thermal generation (utilizing clean fuels or carbon capture and storage) and nuclear.[23]

Maine's renewable energy procurements are advancing Maine's progress towards achieving the state's clean energy goals:

- Maine passed legislation in 2023 that authorizes the state to procure at least 3,000 MW of offshore wind from the Gulf of Maine by 2040, providing guidelines for offshore wind energy procurement and for the establishment of regional transmission solutions.[24] Maine will also have a floating offshore wind research project,[25] which features an innovative floating platform designed by the University of Maine. At 144 MW, this will be one of the largest pre-commercial scale (50–200 MW) floating offshore wind projects in the world.[26]
- Maine also plans to develop renewable energy resources in northern Maine equal to at least 18% of Maine's 2019 retail sales, as well as transmission to connect these resources to the ISO-New England (ISO-NE) grid, as part of the Northern Maine Renewable Energy Development Program.[27]
- Maine legislation directed the Maine Public Utilities Commission (PUC) to procure long-term renewable energy generation contracts to supply 14% of Maine's 2018 retail sales.[28] As a result of

---

20 "Maine Public Utilities Commission Annual Report on the Renewable Portfolio Requirement," Report for 2022 Activity, March 25, 2024.

21 State of Maine, Office of Governor Janet T. Mills, "Governor Mills: Maine Stands on Solid Fiscal Footing, State of the Budget is Strong," February 14, 2023.

22 EIA, Today in Energy, "Five states updated or adopted new clean energy standards in 2021," February 1, 2022, Accessed March 5, 2024.

23 The modeled clean electricity resources in this study include renewables as well as other alternative clean technologies, such as gas plants utilizing clean fuels or with carbon capture and sequestration, new nuclear, and new large hydropower.

24 L.D. 1895 "An Act Regarding the Procurement of Energy from Offshore Wind Resources;" 35-A M.R.S. §3404: Determination of Public Policy; State Wind Energy Generation Goals.

25 35-A M.R.S. §3210-H. Floating Offshore Wind Research Array; Project Labor Agreements.

26 FAQs: Gulf of Maine Floating Offshore Wind Research Array | Governor's Energy Office

27 35-A M.R.S. §3210-I. Northern Maine Renewable Energy Development Program.

28 35-A M.R.S. §3210-G. Renewable Portfolio Standard Procurement.

this procurement, Maine currently has 200 MW of operational renewable energy resources, most of which is solar, and another 300 MW is under development.[29]

- Maine is also encouraging the development of renewable resources on contaminated land that may no longer be used for agricultural purposes. Maine PUC is authorized to conduct competitive solicitations for Class IA resources, which may be combined with energy storage systems, to supply 5% of Maine's 2021 retail sales.[30]
- The Maine Legislature established a goal of 750 MW of distributed generation under the Net Energy Billing programs.[31] As of the end of 2023, about 800 MW of distributed generation, including solar, hydro, wind, and other resources, is enrolled and operational in the programs. About half of this capacity is behind-the-meter and is treated as reducing load, while the remainder is front-of-the-meter. The GEO will also implement a new distributed solar and storage program authorized by the Maine Legislature.[32]
- The Maine PUC administers the "Combined Heat and Power Program," which promotes facilities that use wood to generate electricity and heat for industrial or space heating purposes. The program will support up to a total net generating capacity of 30 MW across all participating facilities.[33]
- Maine utilities also have other resources under contract (close to 40 MW) through the Community-Based Renewable Energy Pilot Program[34] and about 230 MW of operational projects procured under the authority of Maine legislation 35-A M.R.S. §3210-C,[35] which directed utilities to enter long-term contracts for capacity resources and their associated energy or renewable energy credits (RECs).

These new planned and contracted resources, on top of the renewable resources Maine is currently utilizing, will meet most of Maine's clean electricity demand by 2040, as illustrated in Figure I-4 below. For the purpose of this figure, clean electricity demand (shown as the red dashed line) represents the RPS requirement until 2030, and 100% of total electricity demand in 2040 and beyond; it is interpolated smoothly between. The timelines for the resources and the annual generation quantities shown in the figure are approximate and will depend on actual contract schedules as new resources are procured. The "Existing Renewable Energy Supply" block at the bottom represents the current RPS compliance (51%), which is met by REC purchases, largely from hydropower and biomass. The figure assumes these resources will continue to be available in the same quantities going forward, to illustrate how incremental planned resources compare to

29 "An Assessment of Maine's Renewable Portfolio Standard" prepared by Sustainable Energy Advantage, LLC, for the Maine Governor's Energy Office, in collaboration with the Public Utilities Commission, March 31, 2024. The state will be re-bidding the cancelled contracts and is committed to achieving the goal of this legislation.

30 35-A M.R.S. §3210-J. Renewable Energy Procurement; Reuse of Contaminated Lands.

31 35-A M.R.S. §3209-A. Net Energy Billing.

32 2 M.R.S. §9. Governor's Energy Office (6-A).

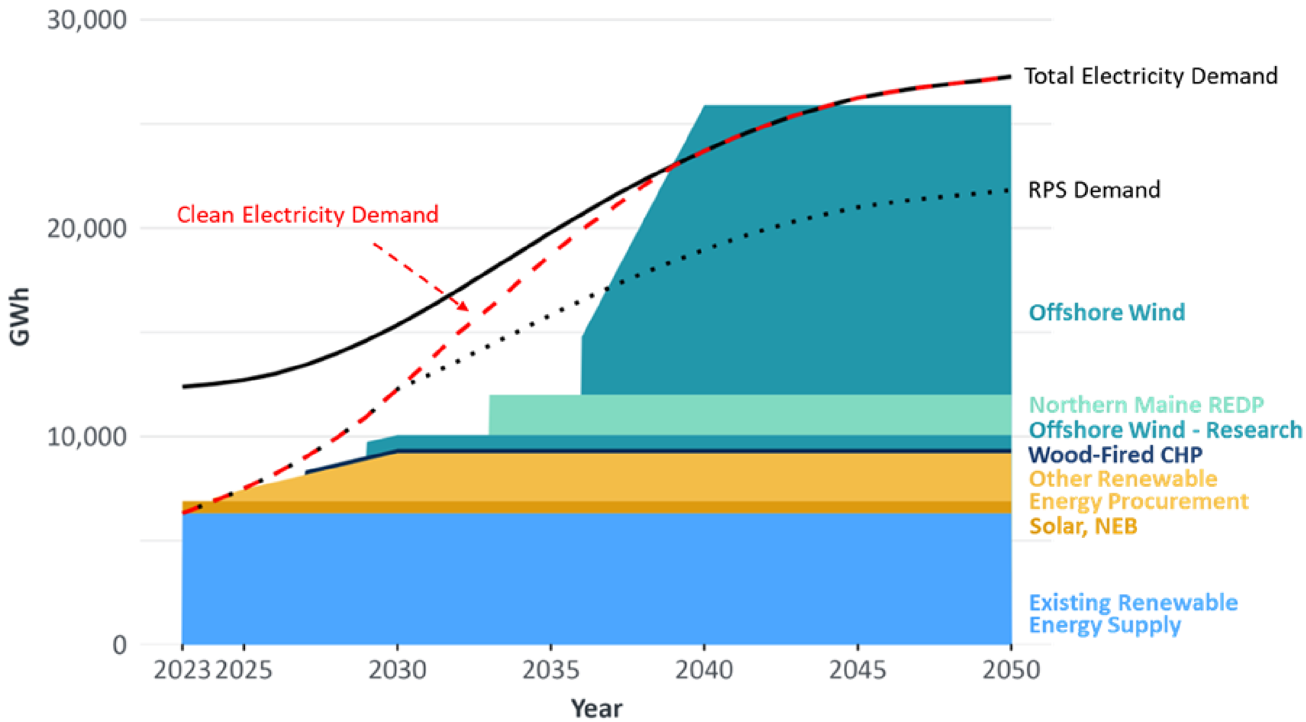
33 35-A M.R.S. Chapter 36-A: Wood-Fired Combined Heat and Power Act.

34 35-A M.R.S. Chapter 36: Community-Based Renewable Energy.

35 35-A M.R.S. §3210-C. Capacity Resource Adequacy.

incremental clean energy requirements.[36] The remaining gap between the clean electricity demand and the planned/contracted resources will need to be met by additional contracts or increased REC purchases.

FIGURE I-4: MAINE'S CLEAN ELECTRICITY DEMAND AND PLANNED/CONTRACTED RESOURCES



Notes: Chart based on information available in March 2024. In-service dates for future projects are assumed based on available data and statutory requirements. "Clean Electricity Demand" is the product of (growing) load and the percentage of load to be sourced from clean (including renewable) resources as required by law. "Total Electricity Demand" (solid line) shows the projection of retail sales net of distributed generation and is grossed up for line losses. "RPS Demand" (dotted black line) is based on retail sales, also grossed up for losses, and the RPS percentage until 2030, held at 80% beyond 2030 for reference. "Northern Maine REDP" represents the Northern Maine Renewable Energy Development Program, assumed to be filled by an onshore wind resource. "Other Renewable Energy Procurement" includes contract authority pursuant to 35-A M.R.S. §3210-G and 3210-J.

[36] The existing resources would need to be repowered by replacing older equipment parts with newer ones to ensure continued operation. As a result of repowering with more modern equipment, the resources may have increased efficiency and greater generation capacity.

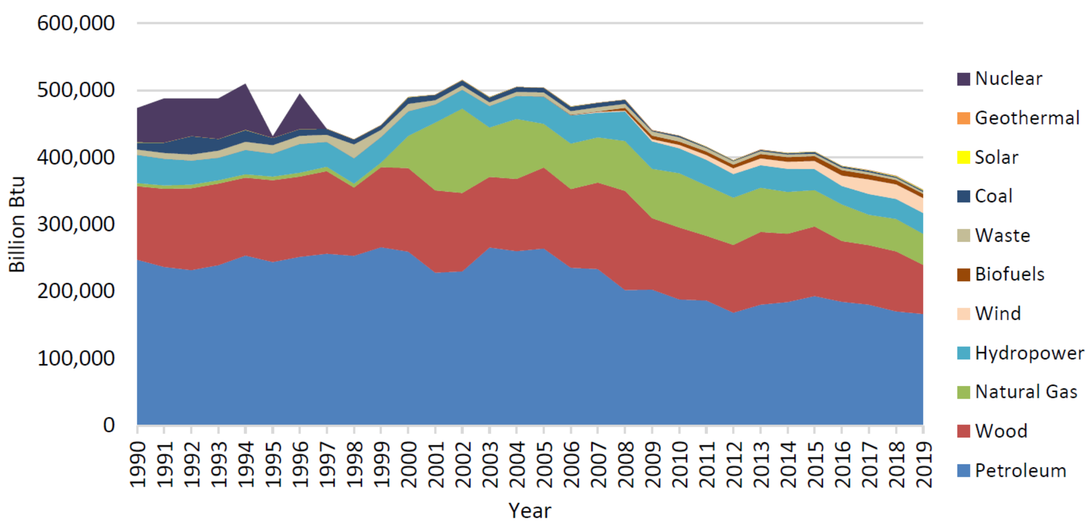
C. Background on Maine's Current Energy System and GHG Emissions

BRIEF OVERVIEW OF MAINE'S ENERGY SYSTEM

As shown in Figure I-5 below, Maine consumes energy from a variety of sources. Petroleum products historically account for the largest share of Maine's energy consumption, used primarily for transportation, and for residential and commercial heating. Maine has no fossil fuel reserves, and thus it imports all the petroleum and other fossil fuels (i.e., natural gas, propane, and coal) that are consumed in the state. Maine also utilizes a large share of wood-derived energy for industrial uses, as well as residential and commercial heating, given Maine's vast forested land, which covers 90% of the state's land area (the largest share of any state). Besides biomass, Maine also has ample renewable energy resources such as hydro and (increasingly in recent years) wind and solar that are used for electricity generation. Maine is the most heating oil-dependent state in the country, with the highest residential heating oil usage per capita and the highest share of households (56%) relying on heating oil, compared to the U.S. average of just 4% (Figure I-6). While other New England states are more oil-dependent for heating than the U.S. average, they are well below Maine (e.g., 22% in Massachusetts, 40% in New Hampshire), generally relying more on natural gas for heat. According to the U.S. Census Bureau, Maine saw a 10% decrease in heating oil as a primary fuel for home heating between 2018 and 2022. This coincided with an increase in households utilizing electricity during that time and Maine's record adoption of high efficiency air source heat pumps, which surpassed the state's goal of 100,000 new installations in July 2023, two years ahead of schedule.[37]

One of Maine's goals is to ensure energy supply is affordable. As Maine invests in clean energy infrastructure, its residents will be more protected from the global fuel price volatility. Energy costs for Maine households have increased in recent years due to rising electricity and delivered fuel prices. Residential electricity rates in Maine have nearly

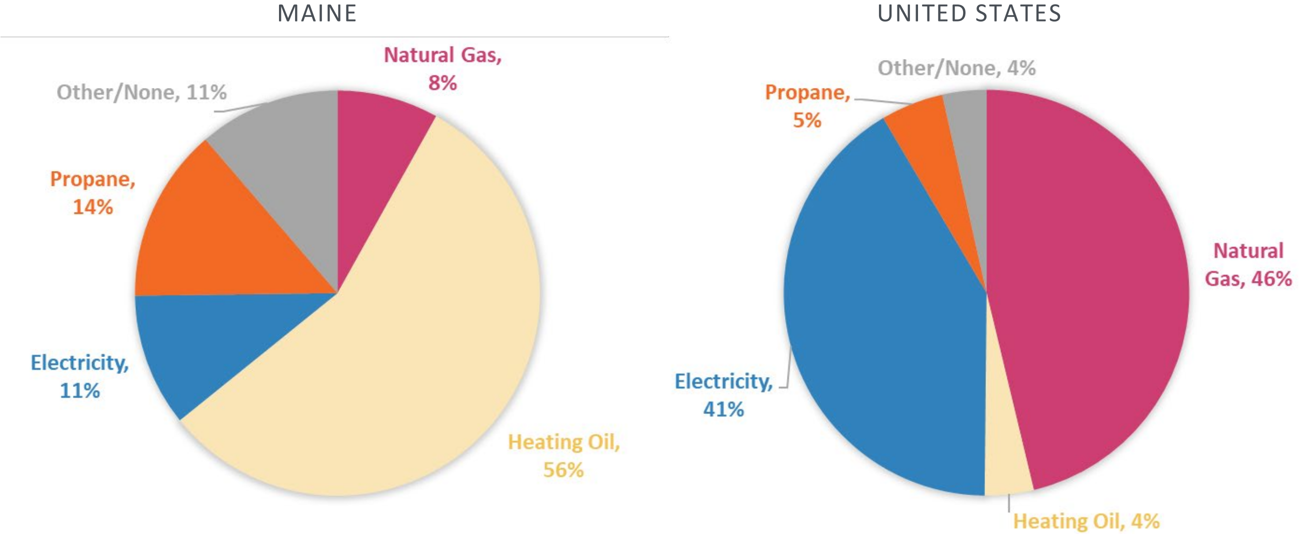
FIGURE I-5: MAINE ENERGY CONSUMPTION 1990–2019



Note: Figure sourced from Maine DEP, "Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals," 2022. Figure data from EIA State Energy Data System. Electricity imports (~13,000 GBtu in 2019) are not shown in the figure.

[37] Maine Governor's Energy Office. "Governor's Energy Office Releases Updated Guide to Help Maine People Save Money and Stay Warm This Winter." November 9, 2023. Accessed May 6, 2024.

FIGURE I-6: SHARE OF HOUSEHOLDS BY ENERGY SOURCE USED FOR HOME HEATING, 2022



Source: Data from U.S. Energy Information Administration, "Maine State Energy Profile Data," February 15, 2024. "Other/None" category includes households heating with wood (8.6% of total for Maine), as well as a small percentage of households that use various other fuels or report no fuel use for heating.

doubled in the past two years due to increased prices for natural gas, which is used to generate electricity.[38] Similarly, heating oil prices reached nearly $6 per gallon in 2022 and leveled off at around $4 per gallon in 2023.[39] The transition to a clean energy system can serve as a safeguard against future price volatility, since the cost drivers of a low-carbon energy system depend minimally on fuel prices.

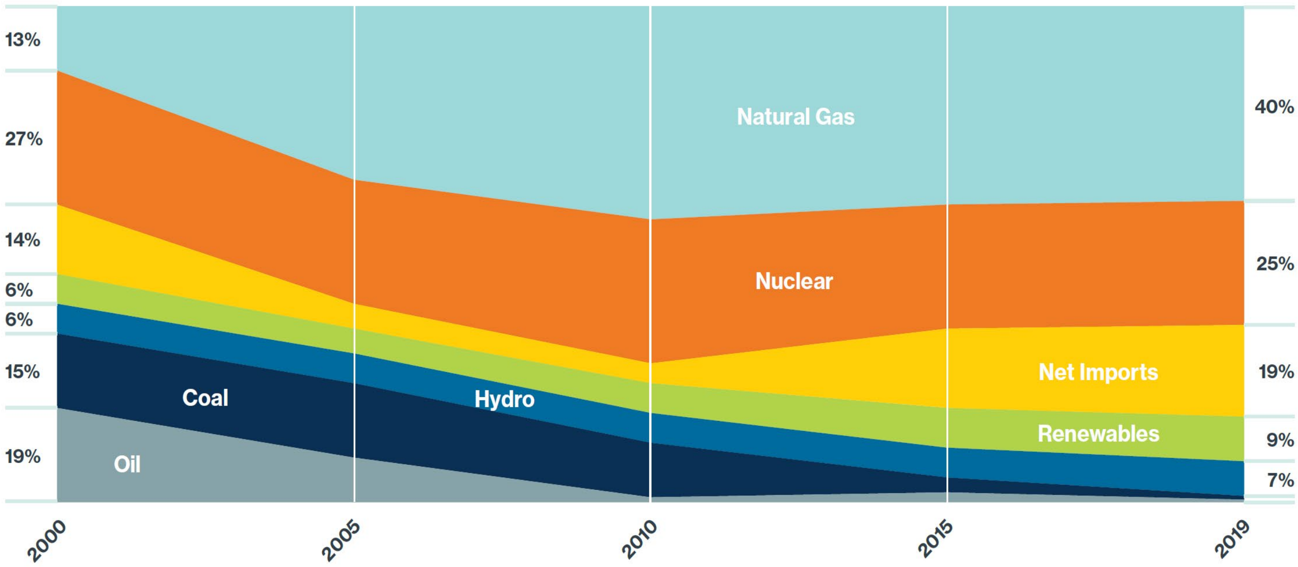
Most of Maine is part of the ISO New England (ISO-NE) regional electricity grid. The separate and much smaller northern Maine grid, managed by the Northern Maine Independent System Administrator (NMISA), is electrically connected only to New Brunswick. Thus, the electricity generated within Maine is not necessarily consumed within Maine, and vice versa. With about 12 TWh of electricity consumption in 2023, Maine accounts for roughly 10% of New England's total electricity consumption. The generation resources on the ISO-NE grid include natural gas, nuclear, wind, solar, hydropower, and biomass, along with imported electricity (Figure I-7). Coal and oil-fired resources in the region have largely retired (though some gas-fired generators can and do rely on oil as a backup fuel for reliability when gas is unavailable). Like Maine, most other New England states have set GHG emission reduction targets and have ambitions to transition to low-carbon resources for electricity as well as other energy demands. As the region transitions to a low-carbon electricity mix, it will be crucial to maintain grid reliability.[40] This means making sure electricity is available continuously when and where it is needed. While increasing amounts of intermittent renewable resources may pose reliability challenges, the transition also offers various solutions such as energy storage and demand-side management as well as infrequent operation of existing thermal electricity generation to balance supply and demand.

38 Maine Governor's Energy Office. "Electricity Prices." Accessed May 6, 2024.

39 Maine Governor's Energy Office. "Heating Fuel Prices." Accessed May 6, 2024.

40 Independent System Operator for New England. "What Is Reliability?" Accessed May 6, 2024.

FIGURE I-7: SHARE OF TOTAL ELECTRICITY BY RESOURCE TYPE IN NEW ENGLAND (ISO-NE)



Source: ISO-NE. Figure obtained from the "2022 Maine Energy Summary and Assessment," State of Maine Office of The Governor, March 15, 2022.

In 2023, about 65% of Maine's in-state electricity generation came from renewables, including hydropower, wind, solar, and biomass, with the remainder coming mostly from natural gas-fired power plants. Not all of the in-state renewable generation necessarily serves Maine's renewable energy policy goals, since generators in Maine can also sell their RECs to other New England states, and some resources are contracted to serve loads in other states. To comply with the state's RPS policy, competitive electricity providers serving customers in Maine must demonstrate that a given percentage of their supply (51% in 2023, rising to 80% by 2030) comes from eligible resources within or outside Maine. [41] Appendix B: Key Energy Technologies provides further background on the status of supply and demand side energy technologies in Maine.

MAINE'S PROGRESS TOWARDS REDUCING GHG EMISSIONS

Maine has already shown progress towards achieving its GHG emission reduction goals. Maine's gross GHG emissions peaked at 38.5 MMTCO2e (million metric tons of CO_2 equivalent) in 2002 and have declined steadily since. As of 2019, the most recent GHG inventory, total annual gross GHG emissions in Maine were 24.2 MMTCO2e, 25% below 1990 levels (Figure I-8). [42]

[41] 35-A M.R.S. §3210. Renewable Resources.

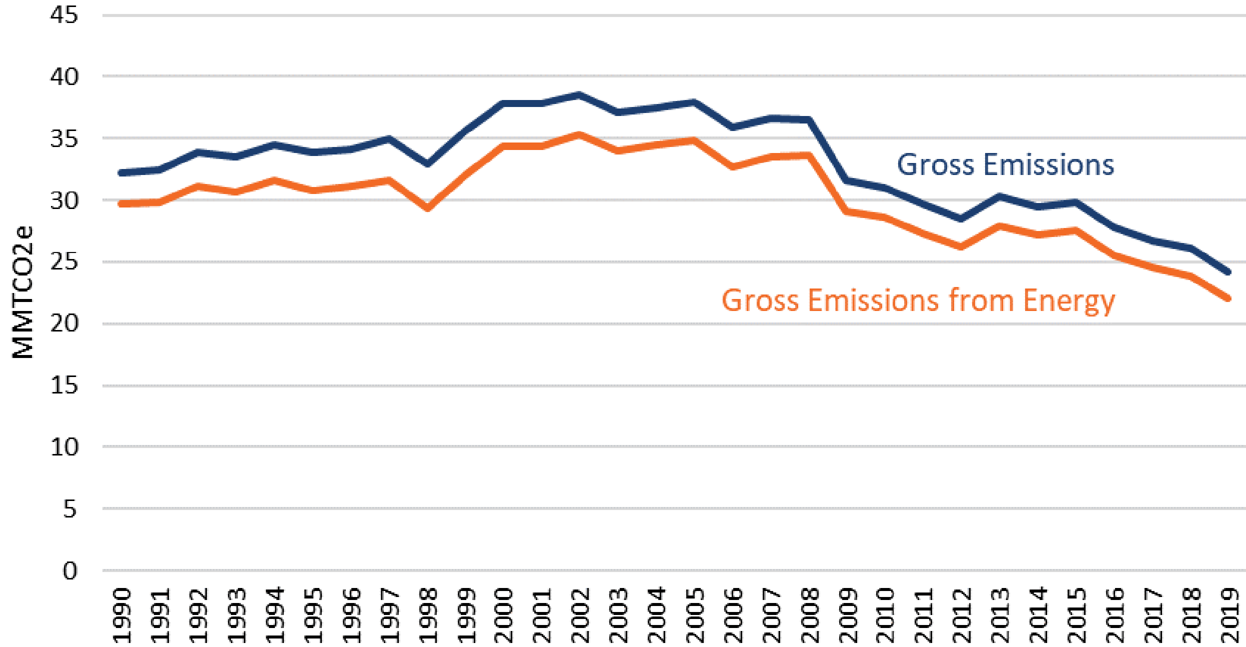
"An Assessment of Maine's Renewable Portfolio Standard" prepared by Sustainable Energy Advantage, LLC, for the Maine Governor's Energy Office, in collaboration with the Public Utilities Commission, March 31, 2024.

[42] Net GHG emissions = Gross GHG emissions − Net Sequestration.

"Gross GHG emissions" means the sum of all anthropogenic GHG emissions released to the atmosphere by all sources. These include emissions from the combustion of fossil fuels and biogenic emissions from the combustion of biofuels, such as wood, ethanol, biodiesel, and waste.

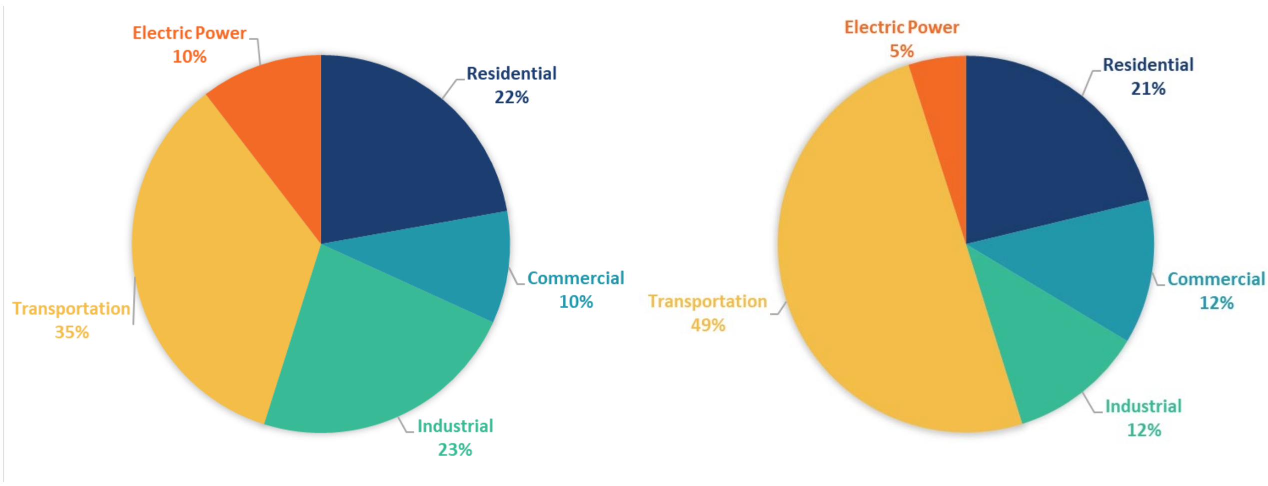
"Net GHG emissions" means gross GHG emissions less the total amount of GHG absorbed by greenhouse gas sinks, natural or manmade, including, but not limited to, trees, crops, soil, and wetlands within the State.

FIGURE I-8: MAINE'S GROSS GREENHOUSE GAS EMISSIONS 1990–2019



Source: Maine DEP, Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals, July 2022, Table A1. Gross emissions shown include biogenic emissions, resulting from the combustion of biofuels, such as wood, ethanol, biodiesel, and waste.

FIGURE I-9: GROSS GREENHOUSE GAS EMISSIONS FROM ENERGY, BY SECTOR, FOR 2019, FROM FOSSIL FUEL AND BIOGENIC SOURCES (LEFT) AND FROM FOSSIL FUEL COMBUSTION ONLY (RIGHT)



Source: Maine DEP, Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals, July 2022, Appendix A4.

Most of Maine's gross emissions (91% in 2019) originate from energy consumption in the residential, commercial, industrial, and transportation sectors and by electric power production.[43] Figure I-9 shows the proportions of Maine's gross GHG emissions from fossil fuel combustion by sector, as of 2019. Transportation was the largest single source of energy-related emissions from fossil-fuel combustion, at 49%. The residential sectors accounted for the next highest contribution with 21%. The commercial and industrial sectors each had 12% shares.

According to a preliminary estimate by the Department of Environmental Protection, 75% of 2016 gross GHG emissions are offset by sequestration in the environment. Maine's forest cover provides a large capacity to store carbon and offsets a high share of the state's anthropogenic emissions. By this measure, in 2016, Maine was approximately 75% of the way toward achieving carbon neutrality (note this is not the same as a 75% reduction in net GHG emissions from the 1990 baseline). According to the DEP's Ninth Biennial Report, Maine could reach carbon neutrality by 2033 if it maintained a continuous glide path of gross GHG emissions that meets the *Maine Won't Wait* climate action plan goals, though this depends on several other assumptions, including that recent high forest sequestration rates will be maintained indefinitely.[44]

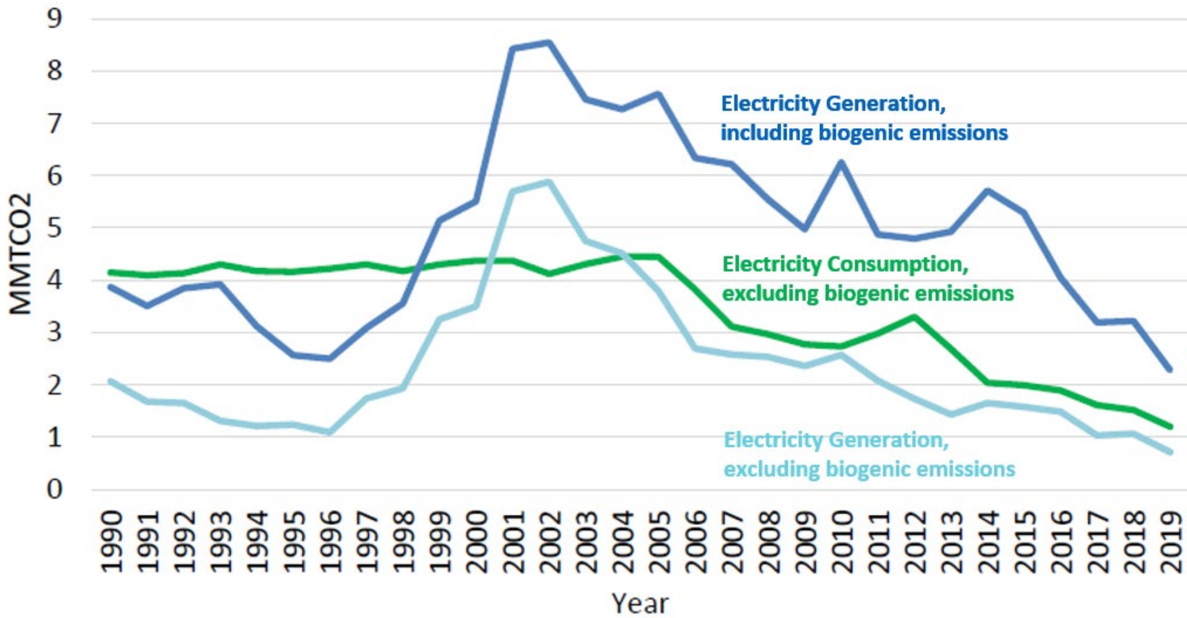
Emissions associated with electricity can be viewed in two alternative ways: emissions from in-state *electricity generation* vs. emissions attributable to in-state *electricity consumption*. It is important to distinguish the two because certain policy requirements may apply to one or the other. Because Maine is part of the New England electricity grid operated by ISO-NE, electricity consumed in Maine may be generated anywhere across the ISO-NE grid or imported from other jurisdictions beyond. Maine's RPS (e.g., 80% renewable by 2030) applies to retail electricity *consumption* by end-users; each electricity provider is required to supply the mandated percentage of their total electric sales using electricity generated from eligible resources. Similarly, the 100% clean electricity by 2040 goal applies to electricity consumption.

On the other hand, Maine's gross GHG emission accounting approach and its carbon neutrality goal refer to emissions from in-state electricity *generation*, whether it was consumed in the state or exported elsewhere, since these are emissions physically emitted to the atmosphere within Maine's borders. This approach does not account for emissions associated with power that may be imported from outside Maine to supply in-state consumption, nor does it subtract out in-state fossil generation that is exported. Figure I-10 compares electricity emissions in Maine based on generation vs. emissions based on consumption. There was an increase in generation-based emissions in the late 1990s through early 2000s, mainly due to an increase in natural gas use by electric generators based in Maine. These emissions have been declining since their peak in 2002. CO_2 emissions from electricity generation decreased by about 40% since 2019, and 70% since the peak in 2022.

[43] The remaining 9% resulted from "non-energy" sectors including agricultural practices, industrial processes with non-combustion activities, and waste disposal and management.

[44] *See* Figure 17 in Maine DEP, Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals, July 2022.

FIGURE I-10: CO_2 EMISSIONS FROM ELECTRICITY GENERATION VERSUS CONSUMPTION IN MAINE



Note: Figure adapted from Maine DEP, Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals, July 2022. Electricity consumption data with biogenic emissions is not available.

II. Pathway Modeling Approach

A. Overview of Pathway Modeling

This study takes a pathway modeling approach to compare several alternative pathways by which Maine could achieve its energy goals, to illuminate some of the advantages and disadvantages, and the opportunities and challenges associated with alternative pathways. It aims to provide support for policymakers, industry, and stakeholders on the trade-offs, decisions, and actions needed to ensure affordable, reliable, clean energy for the state. The modeling approach integrates input from stakeholder groups and the wider public obtained through the stakeholder engagement process.

A set of simulation modeling tools is used to characterize Maine's economy and energy needs over the next several decades, incorporating population and economic growth, energy-intensive activities, and the dynamic interactions between energy sectors. These tools are best in class industry standard tools used by a wide range of state and federal policymakers, regulators, utilities, research institutions, and others to project future energy planning scenarios in order to inform decision making and policy. They account for the context of the existing energy infrastructure, and the available and evolving technological alternatives that can expand or replace it over time.

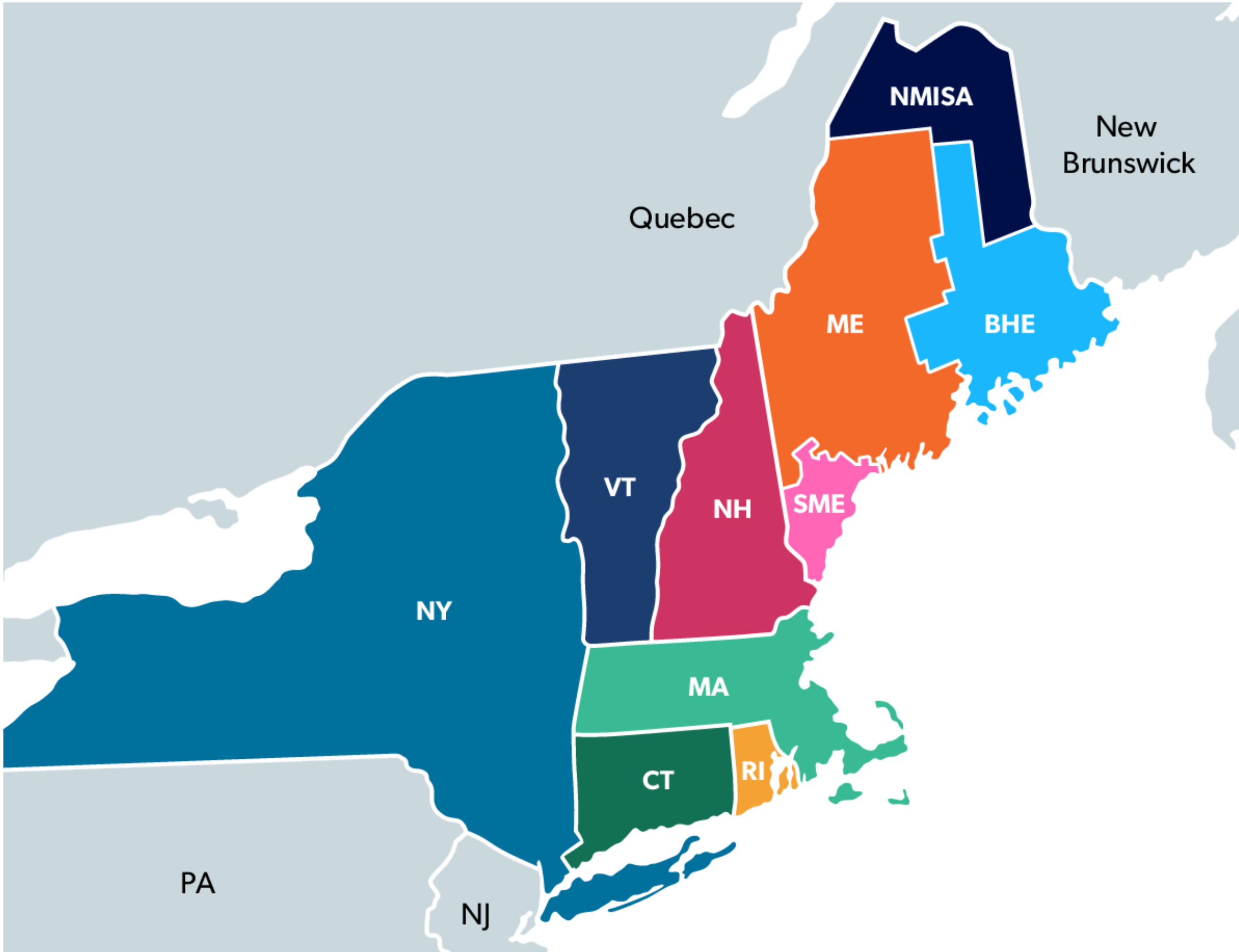
For any given pathway, EER's **EnergyPATHWAYS** model characterizes energy demand, beginning with assumed penetration trajectories for end-use technologies (e.g., heat pump and electric vehicle (EV) adoption) and using this to develop the corresponding demand for electricity and various fuels. The **Regional Investment and Operations (RIO)** model then optimizes the energy supply systems to serve these demands for electricity and fuels, while simultaneously meeting the region's electricity and emissions goals, taking account of the existing infrastructure and finding the most economic way to meet the pathway's electricity and fuel demands.

The role each model plays in the analytical framework is illustrated in Figure II-1. EnergyPATHWAYS focuses on detailed and explicit accounting of energy system decisions. Modeling assumptions made by the user

FIGURE II-1: HIGH-LEVEL REPRESENTATION OF THE ANALYTICAL FRAMEWORK

	EnergyPATHWAYS (EP)	Regional Investment and Operations (RIO)
Description	Scenario analysis tool used to develop demand-side scenarios across all end-use sectors	Tool to develop cost-optimal energy supply portfolios for all fuel types
Track Record	Many regional, US wide, and international decarbonization studies	Decarbonization studies of the US, Northwest, Mexico, and Europe
Application	Scenario design allows for alternative electrification and efficiency measures, which produces: • Annual energy demand for all fuels (electricity, Pipeline gas, diesel, etc.) • Hourly electricity load shape • These energy demand parameters are inputs to RIO	Demand projections from EP used to produce cost-optimal energy supply portfolios: • Electricity sector capacity expansion • Biomass allocation across fuels • Synthetic electric fuel production • Direct air capture deployment

FIGURE II-2: MODELED STUDY ZONES IN U.S. NORTHEAST



describe the set of potential future scenarios. EnergyPATHWAYS produces demand-side scenarios that result in fuel demand, hourly electricity demand, and a characterization of flexible load. This flows into RIO, which is an optimization platform that finds the least-cost set of energy system decisions. RIO optimizes supply-side energy decisions (including the hourly utilization of flexible load) subject to emissions and clean energy constraints, to meet these demands for a coherent whole-economy pathway that includes a full accounting of all potential energy system decisions.

On the demand side, EnergyPATHWAYS allows simulating a detailed bottom-up representation of all the energy-consuming technologies in Maine, such as space and water heaters, air conditioning units, gasoline vehicles, EVs, and how these will change over time. As electrified applications in heat and transportation replace their fuel consuming counterparts (typically using a stock-rollover approach where new technology is adopted when the old must be replaced), the model estimates how electricity and fuel demands change. EnergyPATHWAYS enables the development of a comprehensive picture of electricity and fuel demands across 80 subsectors of the economy. These projections, coupled with designated demand pathways (such as proportions of full electrification with air source heat pumps, hybrid heating systems, or ongoing fossil fuel use), yield insights into the evolving energy needs categorized by fuel types over time. This includes detailed estimations for hourly electricity demand and the utilization of fossil and clean fuels throughout the modeling horizon.

On the supply side, RIO is used to determine the least-cost way to provide the required electricity and fuels, consistent with meeting reliability, carbon, RPS, and other constraints. RIO optimizes investments and operations starting with the current energy system infrastructure to minimize overall energy system costs. Operational and capacity expansion decisions are co-optimized across the ten geographic study zones (Figure II-2).

RIO incorporates final energy demand in future years, the future technology and fuel options available, and clean energy goals such as RPS. It determines the most cost-effective electric system configuration, considering demand-side management and flexible load potential, available electric generation technologies, and transmission and distribution infrastructure requirements. This process also considers the production of clean fuels, such as generating hydrogen from surplus renewable electricity, prioritizing the use of the most economic options first.

Detailed descriptions of the EnergyPATHWAYS and RIO models are provided in Appendix A.

The modeling approach places Maine within the context of New England and assumes that similar pathways are adopted by the rest of the region based on the similar GHG emissions reduction goals in place in those states. The model takes into account the current GHG reduction goals and mandates of other New England states to align strategies and includes the full ISO-NE electric system, considering Maine alongside the other five New England states—Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont. It also models the neighboring electric systems: Quebec, New Brunswick, New York, the rest of the Eastern Interconnect, and the broader United States electric grid.[45]

B. Description of Pathways

This report develops six distinct pathways for decarbonizing Maine's economy and achieving Maine's clean energy and climate goals. These pathways were developed with stakeholder input and are informed by familiarity with energy system requirements and the capabilities, availability, and costs of various technology types, as well as by experience modeling similar greenhouse gas reduction pathways in other jurisdictions.

These pathways are not intended to identify a single "optimal" pathway. Rather, the alternative pathways provide insights into specific policy options, and test the sensitivities of certain assumptions. They illustrate the key issues and trade-offs, and inform the development of strategies to address those issues to facilitate the transition. While technologies are represented in as realistic a way as possible within this framework, it does not explicitly characterize or evaluate individual energy projects or facilities.

The key assumptions behind each pathway and the broad questions each is designed to address are illustrated in Figure II-3.

Pathways modeled:

- The **Core** pathway characterizes a future with continued electrification of end uses, including space heating and transportation, and reflects the additional electricity demand associated with this. It also incorporates a substantial amount of load flexibility (characterized as "Medium" flexibility, but much more than current levels), particularly for newly electrified loads, characterizing how the timing of load can be altered, within limits, to help meet the needs of the power grid (e.g., EV charging can be delayed

[45] Northern Maine presents a unique context, as it is integrated with the New Brunswick grid but not directly connected to the rest of the state and ISO-NE.

FIGURE II-3: KEY ASSUMPTIONS AND QUESTIONS ADDRESSED FOR EACH PATHWAY

			What is the role of thermal electricity generation?	Is there a benefit to retaining legacy fuel heating?	What is the role of flexible load?		To what extent do DERs reduce upstream costs?
		Core	100% Renewable Generation	Hybrid Heat	High Flexible Load	No Flexible Load	High DER + High Flex
Policy	Electricity	80% RPS by 2030 and 100% clean electricity by 2040					
	Economy-Wide GHG	45% below 1990 levels by 2030 and 80% below by 2050					
Demand side	End-use electrification	High Electrification	*Same as Core*	Hybrid Heat	*Same as Core*	*Same as Core*	*Same as Core*
	End-use load flexibility	Medium	*Same as Core*	*Same as Core*	High	None	High
Supply side	Customer-sited resources	Medium	*Same as Core*	*Same as Core*	*Same as Core*	*Same as Core*	High (~2x)
	Thermal resources	Retain if economic and allow new build. Burn zero carbon fuel by 2040.	Retire in Maine by 2040; across New England by 2050	*Same as Core*	*Same as Core*	*Same as Core*	*Same as Core*
	Planned infrastructure	MPUC contracts, energy storage target, offshore wind target, NECEC, projects equivalent to Aroostook Renewable Gateway and King Pine Wind, distributed solar forecasted by ISO-NE					

by up to 8 hours). Supply modeling is then used to characterize economic capacity expansion and dispatch of no/low-carbon generation in the power sector, consistent with Maine's requirements for 80% renewable electricity by 2030 and 100% clean electricity by 2040. Existing thermal generation assets are retained if they contribute to a least-cost outcome, subject to the constraint that they must utilize carbon-neutral fuels by 2040. This supply modeling also considers the production and use of clean, carbon-neutral fuels to meet remaining fuel demand in hard-to-electrify sectors (e.g., air transport, heavy transport, and some industrial applications).

- The **100% Renewable Generation** pathway assumes that all thermal generation in Maine must retire by 2040, and in the rest of New England by 2050,[46] implying that firm power in the later years must be supplied by a combination of renewables and storage. This simulates the energy system impacts of a policy that interprets Maine's "100% clean electricity" requirement as "100% renewable electricity"—i.e., as if the current RPS requirement were expanded to 100%.[47]
- To better understand the impact of flexible load in the Core pathway, the study also models **No Flexible Load** and **High Flexible Load** pathways. Load flexibility enables customers to adjust the timing of their electricity use (particularly EV

[46] Within this context, combustion-driven thermal generators (i.e., those combusting fuels such as natural gas, fuel oil, or their clean counterparts) as well as nuclear power plants are eliminated in this pathway.

[47] Maine's Renewable Portfolio Standard Class I/IA requirement accepts solar, wind, geothermal, tidal power, fuel cells powered with a renewable fuel, hydroelectric generators that meet all state and federal fish passage requirements, and biomass generators, including generators fueled by wood products and landfill gas. It includes neither nuclear nor combustion generators, even if they run on a clean, carbon-neutral fuel.

charging) to accommodate the needs of the grid. Together, these pathways help illuminate how the availability and extent of customer load flexibility might limit the additional infrastructure requirements for generation, storage, transmission, and distribution and thus reduce overall costs.

- The **Hybrid Heat** pathway assumes that customers use hybrid heating systems (heat pumps backed up with fuel-burning boilers or furnaces for extreme cold conditions, transitioning to clean fuels in the long run) instead of adopting full heating electrification with air-source heat pumps. Such a strategy may allow utilizing smaller heat pumps, and should moderate winter peak electric demands, resulting in reduced needs for clean electric generation and storage capacity, and more limited expansions of the transmission and distribution systems to accommodate those peaks. However, it also requires maintaining two heating systems and retaining some fuel use, which would increase complexity for customers and offset some of the potential savings.
- Finally, the study considers a **High Distributed Energy Resources (DER) + High Flex** pathway, which doubles the assumed adoption of distributed solar and adds 2.7 GWh of behind-the-meter batteries by 2050 and includes the enhanced load flexibility assumptions of the High Flexible Load Pathway. This allows customers to reduce their electricity consumption from the bulk grid by self-generating a portion of their demand or using locally generated power, e.g., from neighborhood solar resources. This also may mitigate the need to expand the transmission and distribution systems, trading off system costs for DER costs.

This study does not consider a pathway that replaces all (or even most) current fossil use across the economy with clean, carbon-neutral fuels. Biomass-based fuels are considerably more expensive than many forms of fossil fuel, and their availability is very limited relative to the scale of current fossil fuel use.[48] Synthetic fuels have greater production potential but are still more costly even after accounting for anticipated technological progress, making them a poor candidate for competing with electrification. While there will very likely be some biofuels and synthetic fuels utilized in the future, they will be used almost exclusively in the long term for high-value uses that are hard to electrify. These may include some industrial applications (high-temperature applications like cement and steel production) and key transportation sectors (air travel and heavy transport). (See "Key Resources on the Homestretch to Achieving 100% Clean Electricity" box in Section III.B.1)

C. Key Assumptions

The study draws on a number of industry standard sources for modeling assumptions used in this analysis. This section gives a brief overview of the assumptions, with a more detailed summary included in Appendix A.

The costs of various electric generation technologies and storage are forecasted based on National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline,[49] adjusted using regional multipliers from NREL's ReEDS model[50] and updated to reflect recent cost increases associated with supply

[48] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. "2023 Billion-Ton Report: An Assessment of U.S. Renewable Carbon Resources," March 2024.

[49] National Renewable Energy Laboratory. "Annual Technology Baseline (ATB)." Accessed March 13, 2024.

[50] National Renewable Energy Laboratory. "Regional Energy Deployment System," 2023.

chain constraints and rising interest rates (which have affected offshore wind in particular, but also other technologies). Many of these cost increases, particularly those related to supply chain disruptions, are likely transient. In the long run, most costs are expected to return to near prior projections.

The study assumes that currently contracted, planned, and committed resources will ultimately be developed. For example, the study assumes the three gigawatts of offshore wind that Maine has committed to will be built by 2040. Similarly, despite the recent cancellation of the Aroostook Renewable Gateway, the study assumes that a project comparable to the King Pine onshore wind project with transmission to connect it to the ISO-NE grid will be completed in a time frame close to its original schedule.

The model captures the buildout of transmission and distribution capacity in four categories: interzonal transmission, intrazonal transmission, local distribution, and generation spur lines. *Interzonal transmission* describes the capacity of transmission across zones that is needed to connect generation resources to load (per Figure II-2); interzonal capacity is increased as needed to cost effectively serve demand.[51] *Intrazonal transmission* describes the capacity of transmission within a zone needed to serve load; its capacity is based on the coincident peak demand of the customer classes (residential, commercial, industrial). *Local distribution* capacity describes the capacity of the lower voltage distribution substations and feeders that connect higher voltage transmission to end-use customers; its capacity is based on the non-coincident sum of peak loads across the different customer classes.[52,53] Lastly, new generation requires *generation spur lines* from the generation facility to the existing high-voltage transmission system. This cost is included as part of the cost of new generation.[54]

Customer end-use load profiles are based on ResStock and ComStock,[55] with space heating loads shaped according to weather (using 2011 weather as a proxy to reflect the winter median peak load). Heat pump costs are derived from U.S. Department of Energy (DOE), NREL, and Energy Information Administration (EIA) sources. The default electric

---

51 Electric transmission costs, including regional cost adjustments, are based on NREL's ReEDS model. National Renewable Energy Laboratory. "Regional Energy Deployment System," 2023.

52 Insofar as electrification increases energy flow and/or coincident peak load above historical levels, the study assumes that 20% of intrazonal transmission costs scale with peak, 60% scale with energy sales, and the remaining 20% are fixed. For distribution, the study assumes 60% of distribution costs scale with peak and the remaining 40% is fixed. These assumptions are based on analysis of utility costs conducted by EER.

53 While some of the existing intrazonal transmission and distribution capacity within Maine may be oversized relative to current peak loads, this study does not rely on any existing "slack" or "headroom" in analyzing intrazonal transmission and distribution capacity requirements. Effectively, this approach assumes that any surplus capacity that currently exists would be maintained into the future. To the extent the system may be able to handle some increased loads without requiring intrazonal transmission or distribution expansion, these assumptions may overstate the incremental costs, though the differences among pathways would still be accurate if any overstatement was similar across pathways.

54 National Renewable Energy Laboratory. "Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020," June 2021.

55 ResStock and ComStock provide statistically representative models of the U.S. residential and commercial building stocks. They leverage open-source modeling software developed by the Department of Energy to produce tens of millions of simulations of hourly loads in different building types across the United States, calibrated based on large data sources of energy use in existing buildings.

vehicle charging profiles are developed using NREL's EVI-PRO.[56]

The heat pump modeling assumes that those customers that fully electrify their space heating with heat pumps size their heat pumps to cover each home's full space heating load down to an ambient temperature of -20°F. This approach minimizes both energy consumption and peak load, reducing costs on the supply side, but results in greater equipment costs than utilizing a smaller heat pump system and relying to a greater extent on backup electric resistance heat.[57]

The Core, Hybrid Heat, and 100% Renewable Generation pathways assume 'Medium' level of load flexibility. In these, two-thirds of EV charging can be delayed by up to eight hours, and 10% of thermal loads (space heating, water heating, and air conditioning) can be shifted by one to two hours. In the High Flexible Load and High DER + High Flex pathways, the study uses more optimistic assumptions of flexibility potential (e.g., 100% of EV charging can be delayed by up to 24 hours, with vehicle-to-grid as an option). The No Flexible Load pathway eliminates load flexibility potential from the model. Figure III-24 provides details on load flexibility assumptions.

Forecasted growth in the installation of behind-the-meter solar is based on projections from ISO-NE in the Core pathway.[58] In the High DER + High Flex pathway, this growth is accelerated to reflect more ambitious adoption of behind-the-meter solar, doubling the deployment of distributed solar in New England by 2050 (23.3 GW vs. 11.7 GW, per Figure III-26).

The availability and cost of bio-based fuels are bounded according to the limits found in the U.S. DOE's Billion-Ton Report[59] and Princeton Net Zero America Project.[60] The production of synthetic fuels is modeled endogenously within the model, using, for example, captured carbon and electricity-derived hydrogen, when this is economically competitive against alternative emissions reduction strategies.[61]

Energy efficiency improvements (including building shell and appliances) are based on projections from U.S. EIA Annual Energy Outlook (AEO) 2023[62] and National Energy Modeling System (NEMS).[63] Projections of fuel economy improvements in transportation and vehicle miles traveled are based on AEO and NREL's Electrification Futures Study.[64] These are fully documented in EER's Annual

56 EVI-Pro, developed by NREL in collaboration with the California Energy Commission, draws on detailed data about personal vehicle travel patterns, EV attributes, and charging station characteristics to estimate the charging infrastructure requirements and charging load profiles.

57 In practice, some customers who electrify their homes may choose to install a smaller heat pump in order to lower upfront costs. This would result in greater electricity demands in the winter and, potentially, steeper winter peak loads.

58 ISO New England, "2022 CELT Report," 2022-2031 Forecast Report of Capacity, Energy, Loads, and Transmissions.

59 U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. "2023 Billion-Ton Report: An Assessment of U.S. Renewable Carbon Resources," March 2024.

60 Larson, Eric et al. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," October 2021.

61 As a simplification, such drop-ins are considered to have a net zero carbon emissions profile.

62 U.S. Energy Information Administration. "Annual Energy Outlook 2023." Accessed March 20, 2024.

63 U.S. Energy Information Administration. "Documentation of the National Energy Modeling System (NEMS) Modules," 2023.

64 Sun, Yinong, Paige Jadun, Brent Nelson, Matteo Muratori, Caitlin Murphy, Jeffrey Logan, and Trieu Mai. 2020. Electrification Futures Study: Methodological Approaches for Assessing Long-Term Power System Impacts of End-Use Electrification. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73336.

Decarbonization Perspective 2023.[65] Appendix B.2.e provides further detail on how the energy demand of major end uses for a Maine household changes over time.

All cost inputs and outputs in this report are shown in 2022 dollars.

65 EER. "Annual Decarbonization Perspective 2023 Technical Documentation." Oct 2023.

III. Pathway Results

This study models the six alternative pathways described above, each of which results in Maine achieving its clean energy and greenhouse gas reduction policy goals while maintaining power system reliability. These include a "Core" pathway and five alternative pathways that evaluate the role of key technologies in achieving Maine's policy goals, including thermal generation, hybrid heating systems, load flexibility, and DERs. In all the pathways, three key factors—electrification, clean electricity, and energy efficiency—drive the bulk of emission reductions across the electricity, transportation, buildings, and industrial sectors. These factors are aligned with the strategies outlined in *Maine Won't Wait*. The pathways differ in the balance and particular implementation of these three key factors.

All of the pathways include the following for Maine:

- Electrification of most major end uses that currently rely on fossil fuels, including space heating, water heating, and transportation;
- Deployment of large amounts of new renewable electricity generation to displace output from existing thermal generation and to power newly-electrified loads;
- Production and use of carbon-neutral fuels for certain hard-to-electrify end uses;
- Buildout of power sector transmission and distribution capacity to accommodate increased loads, and to facilitate load balancing across New England and Eastern Canada (imports of Canadian hydropower play an important role for both Maine and New England); and
- Gradual energy efficiency improvements to reduce the incremental energy demand that must be served, though efficiency is not the central driver of emissions reductions.

Additionally, all of the pathways except those noted utilize load flexibility (particularly from EV charging) to help balance supply and demand. Most also retain large amounts of thermal generation capacity to serve as backup generation (eventually using carbon-neutral fuels) for the relatively infrequent instances when renewable generation, storage, and load flexibility are insufficient to satisfy demand.

Each of the alternative pathways modify certain assumptions and constraints from the Core pathway. The analysis of alternative pathways does not intend to establish a single "best" or "optimal" pathway. Rather, the alternative pathways provide insights into specific questions relevant to public policy, including testing the sensitivities of certain assumptions and identifying the timing of important investment decisions.

- The **Core** pathway serves as a baseline for comparison with the other pathways. It is characterized by high electrification of transportation and heating, 'medium' load flexibility, and maintaining thermal generation as a dispatchable resource.
- The **100% Renewable Generation** pathway, which eliminates all fuel-fired thermal generation, illustrates that it would be possible to build out and operate a system without fuel-fired generation, but that it would require more renewable generation and storage capacity to maintain reliability, and would result in higher costs. The additional renewable energy and storage capacity needed to meet this requirement will mostly be added after 2035, but certain decisions to maintain thermal generation capacity and the procurement of additional renewable resources may be made earlier.
- The **Hybrid Heat** pathway results in lower peak electric loads, leading to electric system cost

savings in Maine from 2035 to 2050. However, these savings are largely offset by the cost of purchasing and maintaining dual heating systems and the additional cost of heating fuel.

- A pair of pathways—**No Flexible Load** and **High Flexible Load**—demonstrate that flexible load, particularly flexible EV charging, can help maintain system reliability by actively managing demand, reducing the infrastructure requirements that would otherwise be needed. With flexible load, distribution peaks can be kept lower, reducing the extent and cost of reinforcing the distribution system. Transmission and generation requirements also grow by less, avoiding additional costs. The annual benefits of flexibility grow over time as energy demand and peak load increase from electrification, underscoring the importance of investing in the technologies that enable load flexibility in the near term so that savings are maximized in the long term.
- The **High Distributed Energy Resource (DER) + High Flex** pathway builds on the level of load flexibility in the High Flexible Load pathway and doubles distributed solar PV capacity while increasing distributed energy storage. This pathway results in reductions in infrastructure costs, but these savings are offset by the higher installation cost of DERs. This highlights the importance of focusing on cost reduction strategies for distributed energy in the near term.

To understand the full implications of the factors being tested, similar assumptions are utilized across New England for all pathways. That is, the pathways test the region-wide implementation of the approaches being examined for Maine to understand their general applicability and sustainability. The remainder of this section depicts detailed results of the pathways for Maine's energy future, describing first the Core pathway in detail, and then the alternative pathways, focusing on the key ways in which each differs from the Core pathway.

A. Core Pathway Results

- ✦ It is possible to reliably match electric supply to load on an hourly basis in an electric system that depends largely on intermittent renewable generation.
- ✦ Electricity supply transitions away from fossil generation, with the system relying over time mostly on renewable resources (wind and solar), supported by load flexibility, battery storage, imports of clean energy, and infrequently operated combustion-based thermal generation (providing only <5% of total generation in New England).
- ✦ Widespread electrification of transportation and heating results in electricity demand doubling. It also creates a new winter peak that reaches three times the current summer peak by 2050, despite much greater levels of load flexibility than currently exist.
- ✦ Fossil fuel use declines dramatically; it is replaced with clean fuels in some hard-to-electrify sectors.
- ✦ Total statewide energy supply costs remain relatively similar over time. Electricity supply costs increase, but this is largely offset by the reduction in fossil fuel costs, particularly delivered fuels.

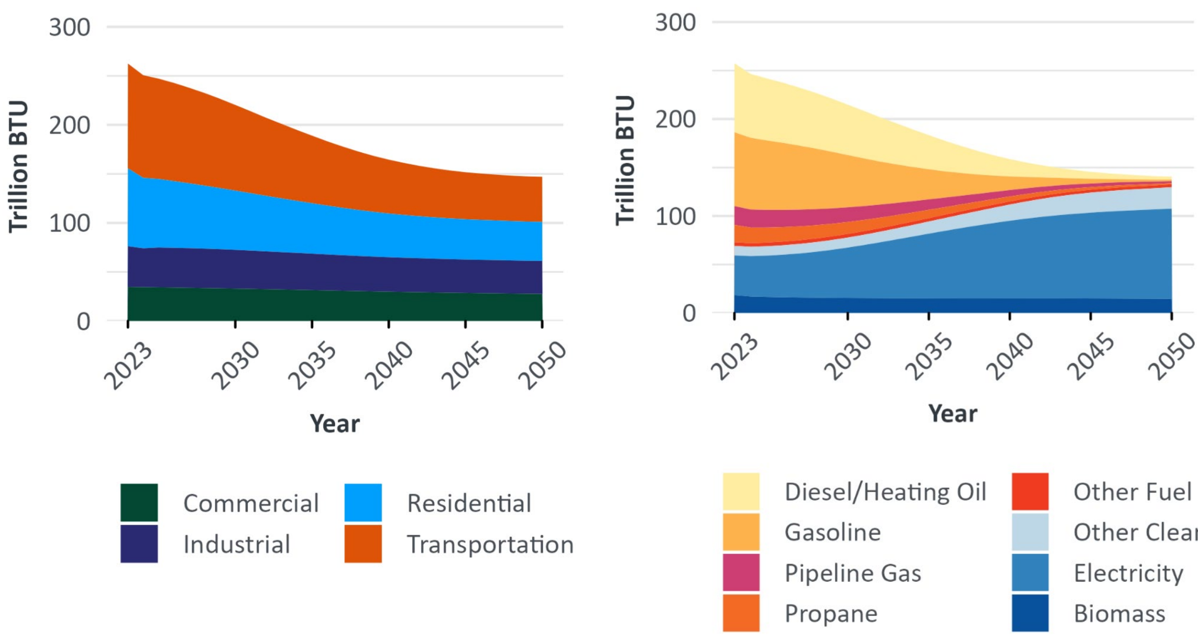
1. Projected Energy Demand

a. Primary Energy Demand

As a consequence of the move from direct combustion of fossil fuels for heating and transportation to reliance on electricity, the total consumption of primary energy drops considerably in Maine, by approximately 40% in 2050 compared to its 2023 level (Figure III-1). This does *not* mean that customers decrease their consumption of energy services; it means that less primary energy is consumed to provide the same services.[66] Reduction in primary energy demand can come from energy efficiency, electrification, or both. For example, energy efficiency improvements, such as building envelope retrofits and adoption of more efficient appliances, contribute to reducing primary energy demand without sacrificing the underlying energy services being delivered (e.g., a well-heated home). Replacing a boiler with a heat pump also reduces primary energy demand because a heat pump can produce the same amount of heat with 1 kWh of electricity as a boiler could with the equivalent of 3–5 kWh of fuel oil.

The composition of energy sources also changes considerably over time, from primarily fossil in the 2020s (shades of red to yellow in Figure III-1, right), to primarily clean by 2050 (shades of blue), most of which is electricity. As the composition of energy sources changes from fossil to clean, GHG emissions decline

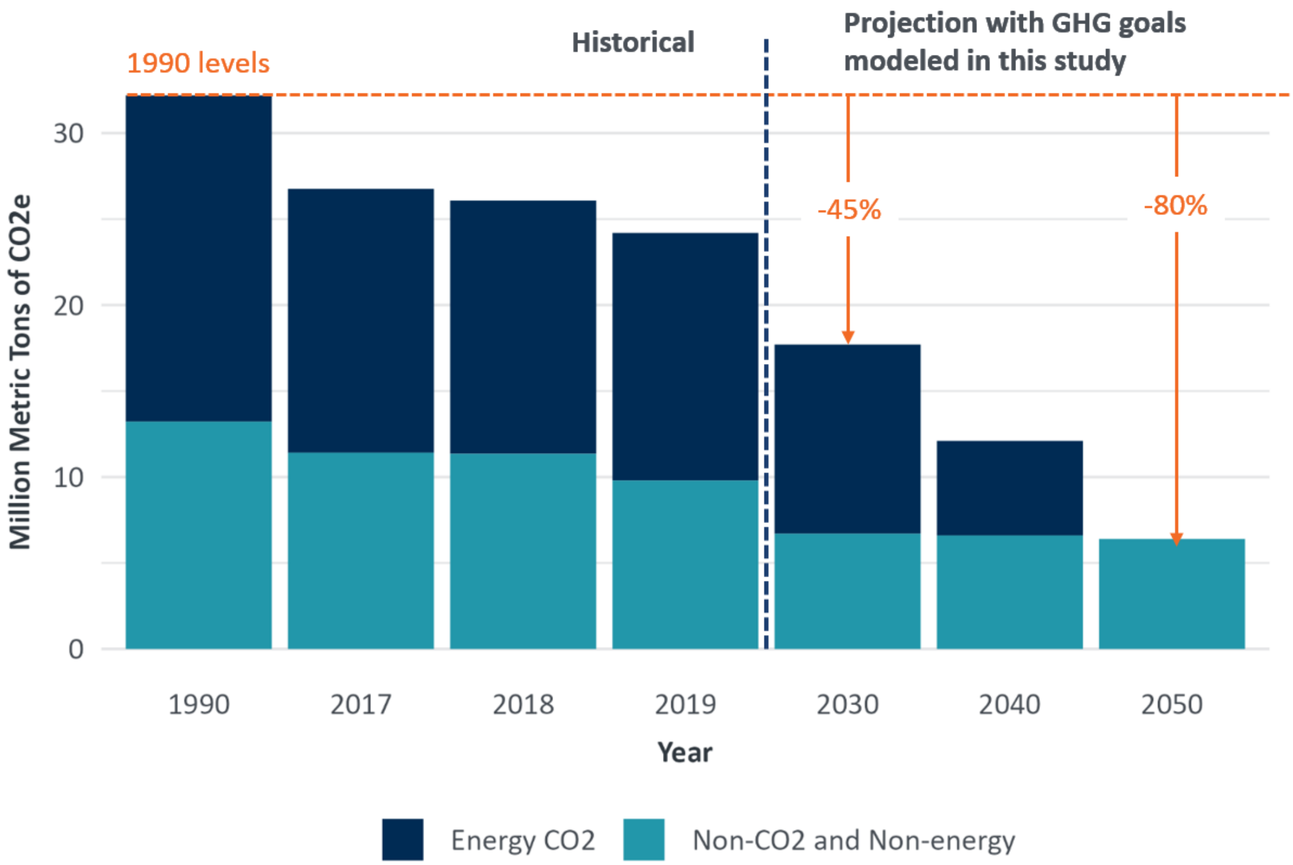
FIGURE III-1: TOTAL ANNUAL PRIMARY ENERGY CONSUMPTION IN MAINE BY SECTOR (LEFT) AND BY ENERGY SOURCE (RIGHT), CORE PATHWAY



Note: "Other Fuel" includes coal, compressed/ liquefied pipeline gas, jet fuel, kerosene, other petroleum, and residual fuel oil; jet fuel accounts for the bulk of this category. "Other Clean" includes ammonia, liquid hydrogen, on-site hydrogen, and steam. Note that while the demand for diesel, gasoline, pipeline gas, propane, and "Other Fuel" has traditionally been met with fossil fuels, many of these demands are met by carbon-neutral alternatives in the long run. The model determines the most economical way to satisfy these demands, subject to constraints on gross and net greenhouse gas emissions.

66 Primary energy measures consumption at the meter, so it does not reflect losses that occur upstream. For example, where natural gas is burned to produce electricity, the figure shows the electricity that is actually delivered to the customer, not the heat that the gas turbine dissipates or electric losses that occur in transit. On the other hand, when natural gas is burned in a conventional furnace, it has already passed through the meter so the heat lost to flue gases and the ambient environment is included as part of primary energy demand.

FIGURE III-2: ANNUAL GREENHOUSE GAS EMISSIONS IN MAINE, CORE PATHWAY



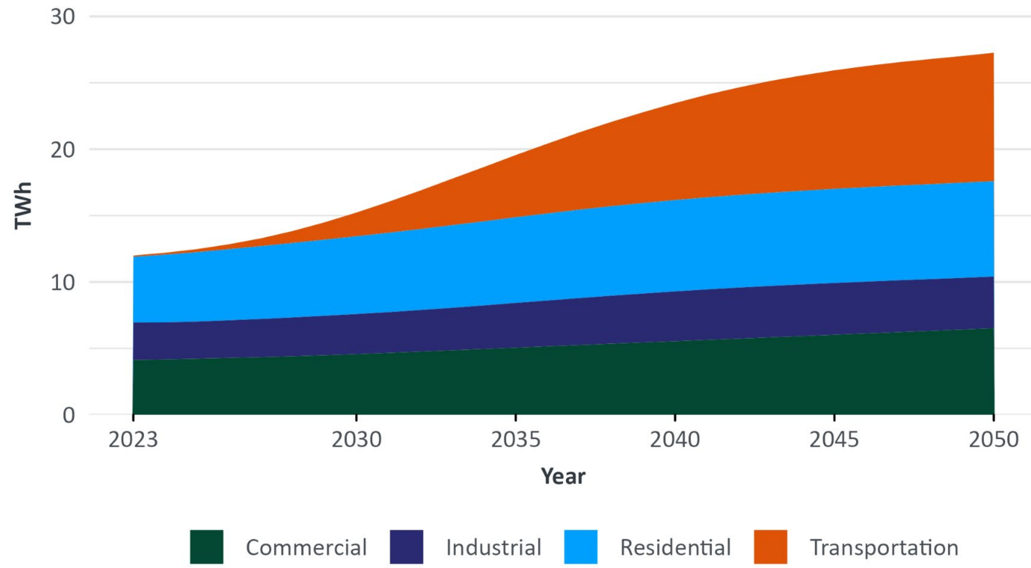
Note: "Energy CO2" includes carbon dioxide emissions from fossil fuel combustion in electric power, buildings, transportation, and industry.

dramatically over time, as required by Maine's GHG reduction goals: 45% below 1990 levels by 2030 and 80% by 2050. These emissions reductions are illustrated in Figure III-2.

The rapid adoption of electric vehicles and electrified heating more than doubles electricity use by 2050, as described in more detail below. At the same time, electrification greatly reduces the consumption of fuels such as gasoline, diesel, heating oil, propane, and pipeline natural gas. As Figure III-1 shows, the consumption of small amounts of pipeline gas, diesel, and other petroleum products (and their carbon-neutral alternatives) remains in 2050, primarily for use in transportation and industry. Pipeline natural gas demand decreases from about 19 trillion BTU in 2023 to 7 trillion BTU in 2040 and 2 trillion BTU in 2050. The reduction in fossil fuel consumption, particularly for motor fuels, accounts for substantial cost savings that offset the cost increases that occur in the electric sector due to growing demand.

From 2030 and beyond, clean fuels are used for long distance transport and industry in modest amounts. The use of clean fuels, including hydrogen-based fuels, increases over time as fuels are decarbonized to meet emissions reduction requirements. These clean fuels are primarily derived from biomass or synthesized from hydrogen produced with electricity, combined with carbon dioxide captured from the air or from biomass feedstock.

FIGURE III-3: ELECTRICITY CONSUMPTION IN MAINE BY SECTOR, CORE PATHWAY



Note: The figure presents the amount of electricity consumption. The additional electricity needed to accommodate transmission and distribution losses is accounted for in the supply-side electricity modeling.

A more detailed analysis of final energy demand forecasts, broken down by sector, is provided in Appendix C: Detailed Forecast of Demand by Sector.

b. Electricity Demand

Maine's annual total electricity consumption is projected to more than double—increasing from 12 TWh in 2023 to 23 TWh in 2040 and 27 TWh in 2050. As shown in Figure III-3, most of the anticipated growth in Maine's electricity demand—approximately 60%—is driven by the electrification of transportation, shifting from traditional fossil fuel-powered vehicles to electric vehicles. Another 30% of the increase comes from electrifying space and water heating in residential and commercial buildings. Electricity demand increases through 2050 are mitigated by energy efficiency measures, which slow the energy demand growth across all sectors.

The remaining 10% of demand growth comes from industrial demand, primarily due to electrifying processes that utilize lower temperature process heat. Efficiency measures also play an important role in limiting industrial demand growth over time.[67]

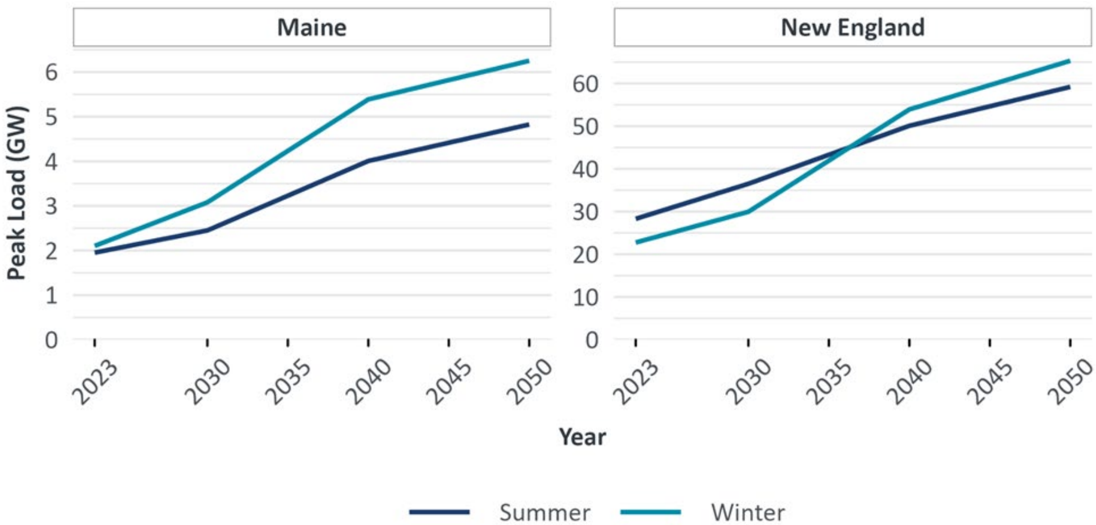
Currently, Maine's electric load peaks at similar levels in the summer and winter, about 2 GW as shown in Figure III-4, while the regional New England grid as a whole is summer peaking. Thus, state and regional planning and resource requirements revolve around summer peak demand. However, in the Core pathway, the widespread adoption of air source heat pumps across the region to electrify space heating demand will cause winter peaks to grow faster than summer peaks. This is forecasted to cause New England overall to become winter peaking by around 2036, and this trend will continue beyond then with ongoing heat pump adoption. Overall loads, summer and winter, will rise substantially with increased EV charging load, though since transportation loads have little seasonality, this will not have a major influence on the seasonality of peak loads. As discussed in detail later,

[67] Industrial energy intensity is assumed to decreases 1% per-year due to efficiency improvements.

EV charging can be flexible, able to shift in time, and thus may have a more limited effect on peak loads.

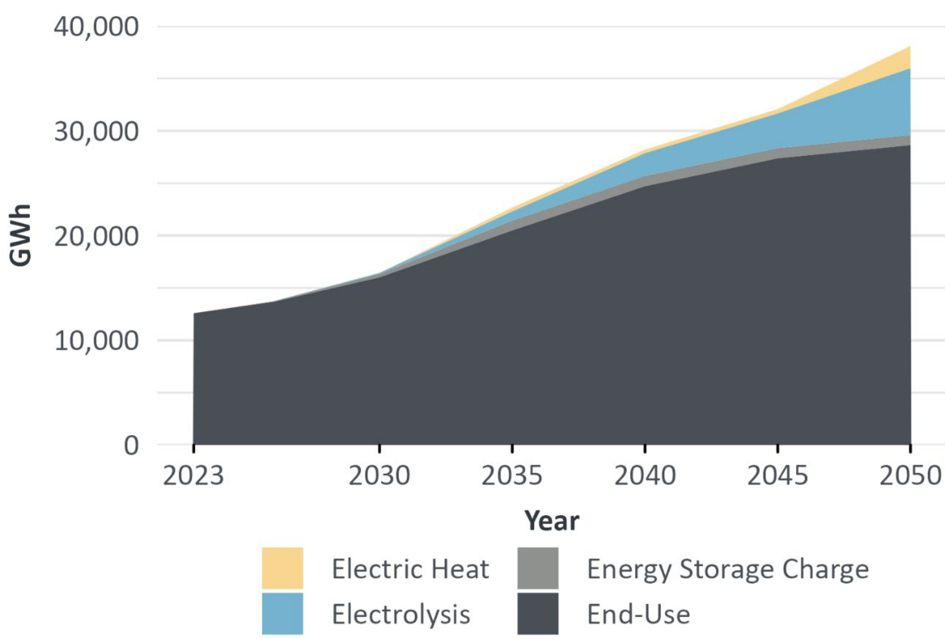
As more renewable resources come online, there will be hours where renewable generation is abundant and exceeds end-use loads. In these hours, flexible industrial energy conversion loads, such as electrolysis and industrial heat production, can be economically dispatched to utilize the surplus renewable energy. In later years, these large industrial loads help to balance the electricity system

FIGURE III-4: MODELED SUMMER AND WINTER PEAK LOADS, BEFORE LOAD FLEXIBILITY



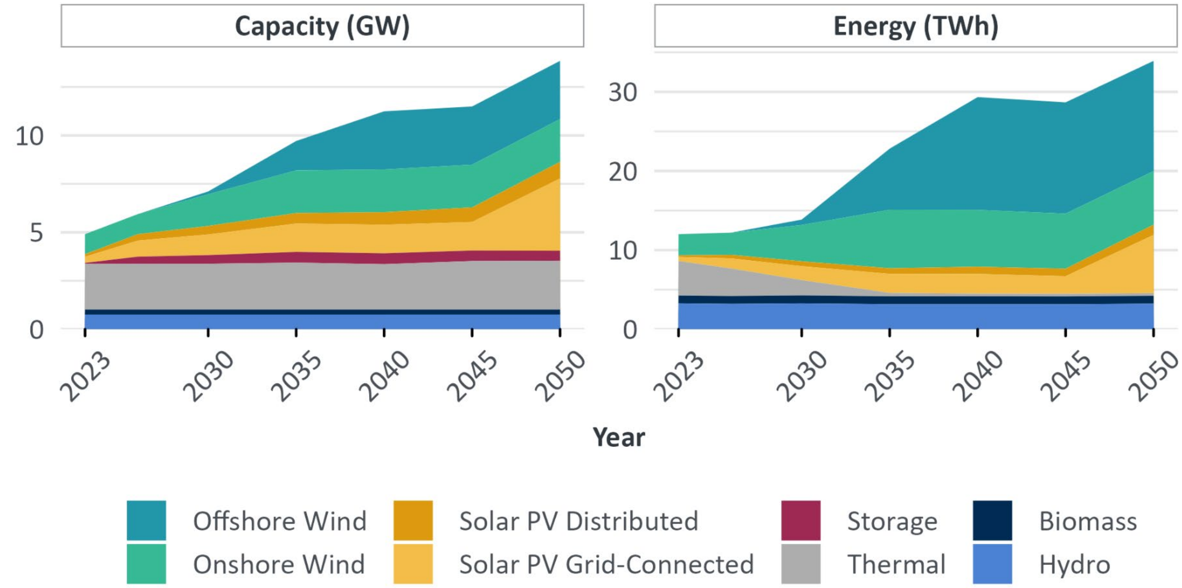
Note: Figure shows the peak loads in the summer and winter in the absence of load flexibility. The peak loads of the system are grossed up by 5% to account for the line losses. Load flexibility, which is mostly achieved by shifting EV charging loads, reduces these peaks in both the summer and winter.

FIGURE III-5: THE GROWTH OF INDUSTRIAL ENERGY CONVERSION LOADS, CORE PATHWAY



Note: The growth of conversion loads is illustrated by the yellow and teal sections in the chart. These include electrolysis (electricity consumed for hydrogen production) and electric heat (electricity consumed to produce industrial heat and steam). End-Use represents the consumption by residential, commercial, industrial, and transportation sectors.

FIGURE III-6: IN-STATE ELECTRICITY SUPPLY IN MAINE, CAPACITY (LEFT) AND ELECTRICITY GENERATION (RIGHT), CORE PATHWAY



and take advantage of the renewable energy that would otherwise be curtailed.

These loads also help decarbonize other sectors, providing electric heat for industrial heat and steam, or clean fuels for hard-to-electrify industrial and transportation applications. The growth of conversion loads is illustrated in Figure III-5 (yellow and teal sections in the chart). Note that electrolyzers—the technology used for the production of hydrogen from renewable energy—are at different stages of commercial readiness, ranging from the laboratory stage to established. While the installed capacity of existing electrolyzers is less than 100 MW in the U.S., this is expected to increase above 3 GW in the near term and continue to grow due to IRA tax incentives.[68]

2. Changing Electricity Supply

As the electrification of transportation and buildings progresses and increases electricity demand, it is essential to grow the supply of zero carbon electricity generation to meet this demand while achieving Maine's clean energy goals and GHG emission reduction targets. This section discusses how Maine—and by extension New England[69]—can adapt its electricity supply to serve this growing demand with clean energy.

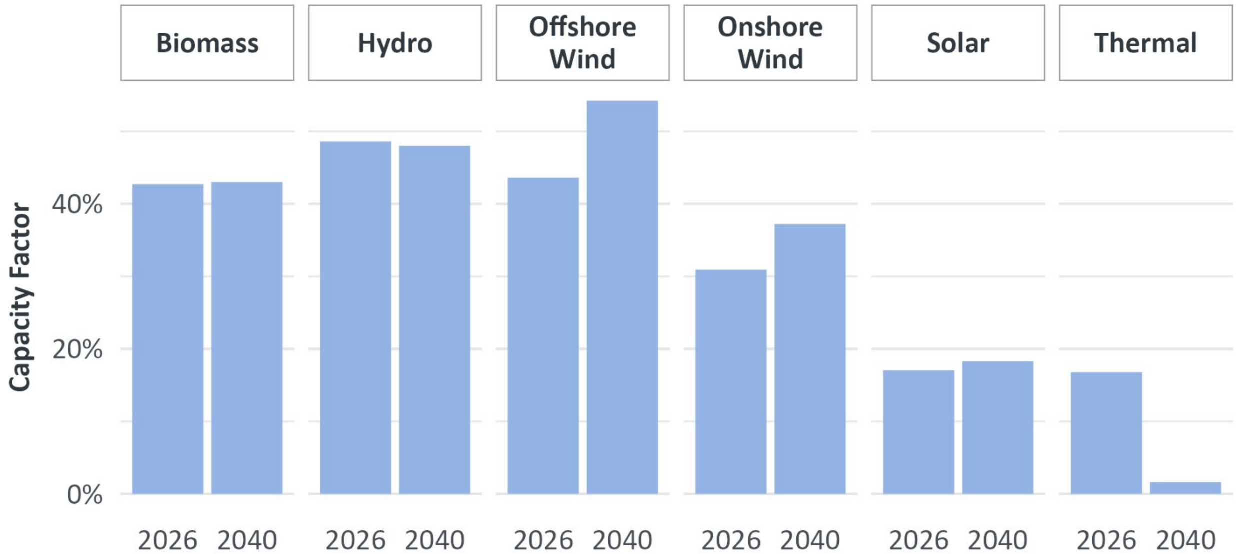
a. Maine Electricity Supply

The generation capacity located in Maine is expected to more than double by 2040. The Core pathway primarily selects new renewable resources to meet expanding energy needs: offshore and onshore wind and solar resources grow to reach 10 GW in total by 2050, representing about 70% of the total generation

68 DOE Hydrogen Program Record, June 2, 2023. Accessed May 7, 2024.

69 The resources physically located within Maine are not necessarily the same as the resources that serve Maine load—some resources in Maine may contract with buyers in other states, and vice versa. Still, understanding the character of the electricity that is produced within Maine may offer a helpful perspective.

FIGURE III-7: CAPACITY FACTORS OF ELECTRICITY GENERATING TECHNOLOGIES IN MAINE, CORE PATHWAY



Note: Capacity factors are computed as model outputs, based on energy production and nameplate capacity. Wind capacity factors increase due to increased turbine size and technological advancement.[71] Solar capacity factors improve to a lesser extent due to lower system losses and technology improvements.[72] The capacity factor of combustion-based thermal resources falls to near zero in 2040 due to infrequent operation, despite that the capacity remains valuable for reliability.

capacity in Maine (Figure III-6, left panel). Electric energy produced in Maine approximately triples by 2050, with the greatest growth coming from offshore wind (Figure III-6, right panel). Onshore and offshore wind expand to account for more than two thirds of generation. Offshore wind's high energy production relative to its installed capacity reflects the high capacity factor of this resource (Figure III-7). Hydropower and biomass resources maintain their existing capacity through 2050. Energy storage (with approximately 2 to 10-hour duration) grows to 515 MW primarily for daily balancing needs.

A key result from the Core pathway is that it is beneficial to retain and even slightly expand the capacity of thermal generation resources in Maine. This is seen in the left panel of Figure III-6, where thermal electricity generation capacity (the gray area) remains essentially level through 2050, [70] even as electricity generation from these resources falls toward zero (Figure III-6, right panel). Despite their low output, these firm capacity resources play an important role in maintaining reliability when generation from renewables wanes. The dispatch of these resources is discussed in greater detail in Section III.A.2.b Maintaining System Reliability.

It is important to note that the model does not make prescriptions for specific power plants; it simply models the capacity of a given type of resource within a zone (per Figure II-2). Over time, some existing thermal power plants may need to undergo upgrades to accommodate decarbonized fuels, while others may be replaced altogether with newer, higher-

[70] Thermal capacity rises slightly over time, from 2.36 GW in 2032 to 2.52 GW in 2050.

[71] National Renewable Energy Laboratory. "2023 Annual Technology Baseline: Offshore Wind." Accessed March 5, 2024.

[72] National Renewable Energy Laboratory. "2023 Annual Technology Baseline: Utility-Scale PV." Tableau Software. Accessed March 5, 2024.

efficiency plants. While there may be certain advantages to locating replacement facilities at the site of existing facilities (due to zoning and the availability of existing transmission infrastructure), such plant-level considerations are largely beyond the scope of this analysis.

Maine currently has contracts and commitments to procure significant additional renewable energy by 2040. Maine passed legislation in 2023 that directs the state to procure at least 3,000 MW of offshore wind, [73] which would produce close to 14,000 GWh per year. The model assumes these resources are built as planned. Maine also plans to develop renewable energy resources in northern Maine and a transmission line to connect these resources to the ISO-NE grid as part of the Northern Maine Renewable Energy Development Program. [74] This analysis assumes procuring 600 MW (~2,000 GWh per year) of onshore wind from a project equivalent to the King Pine wind project for Maine. Although the transmission project for integrating King Pine into the ISO-NE system, the Aroostook Renewable Gateway (ARG), was recently cancelled,[75] this study assumes it or a similar transmission line will be completed since the state remains committed to this project. While the actual configuration, cost, and timing may differ somewhat from the original plan, this would not affect the conclusions substantially.

Maine utilities also have about 470 MW of operational renewable energy resources under long-term contract, and an additional 300 MW of MPUC (Maine Public Utilities Commission)-contracted projects are under development. [76] In the Core pathway, utility-scale solar capacity reaches 1,500 MW by 2040 and 3,700 MW by 2050. Distributed PV installations are also expected to grow by an incremental 500 MW by 2040 and 720 MW by 2050. In aggregate, these solar resources will provide about 3,400 GWh in 2040 and 8,880 GWh in 2050.

The Core pathway selects wind and solar resources to meet load over alternative clean technologies available in the model (including new nuclear and gas plants with carbon capture and sequestration), as this approach results in the lowest energy supply cost subject to physical and policy constraints. [77,78] This indicates that for Maine and greater New England, additional renewable generation—backed by storage and thermal generation for reliability—is the most economic option for satisfying growing electricity demand while achieving climate goals.

Since Maine is located within the New England electricity grid, Maine load is served by resources from throughout New England, as well as from Quebec and New Brunswick. Besides determining the in-state resource mix for Maine, the model establishes the New England generation mix that simultaneously meets every New England state's renewable and clean energy goals and determines requisite imports and exports across the U.S.-Canadian border.

The overall New England resource mix broadly resembles Maine's in-state mix, although there are some notable distinctions (Figure III-8). As a percentage of the total, in 2040, the New England

[73] An Act Regarding the Procurement of Energy from Offshore Wind Resources, 35-A M.R.S.A §3404, sub-§2.

[74] 35-A M.R.S. §3210-I. Northern Maine Renewable Energy Development Program.

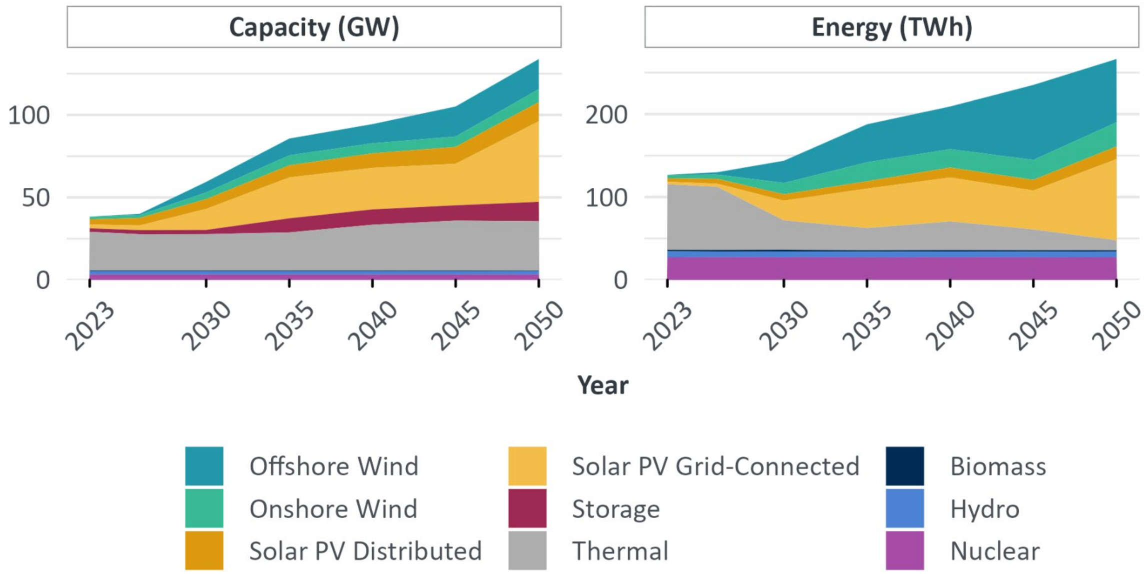
[75] Maine Public Utilities Commission, Docket No. 2021-00369, Order Terminating Procurement, Dec 22, 2023.

[76] "An Assessment of Maine's Renewable Portfolio Standard" prepared for the Maine Governor's Energy Office, in collaboration with the Public Utilities Commission, prepared by Sustainable Energy Advantage, LLC, March 31, 2024.

[77] These constraints include supply always equaling demand (incorporating load flexibility), capacity limits of various resources, and transmission limits between regions, as well as the clean energy and GHG policy requirements. The modeling framework is described in more detail in Appendix A.

[78] There are some additional technological considerations that are not included explicitly in the modeling, but might make these alternative technologies even less attractive, including immature technology with substantial uncertainty about availability, timing, and cost.

FIGURE III-8: NEW ENGLAND ELECTRICITY SUPPLY, CAPACITY (LEFT) AND ELECTRICITY GENERATION (RIGHT), CORE PATHWAY



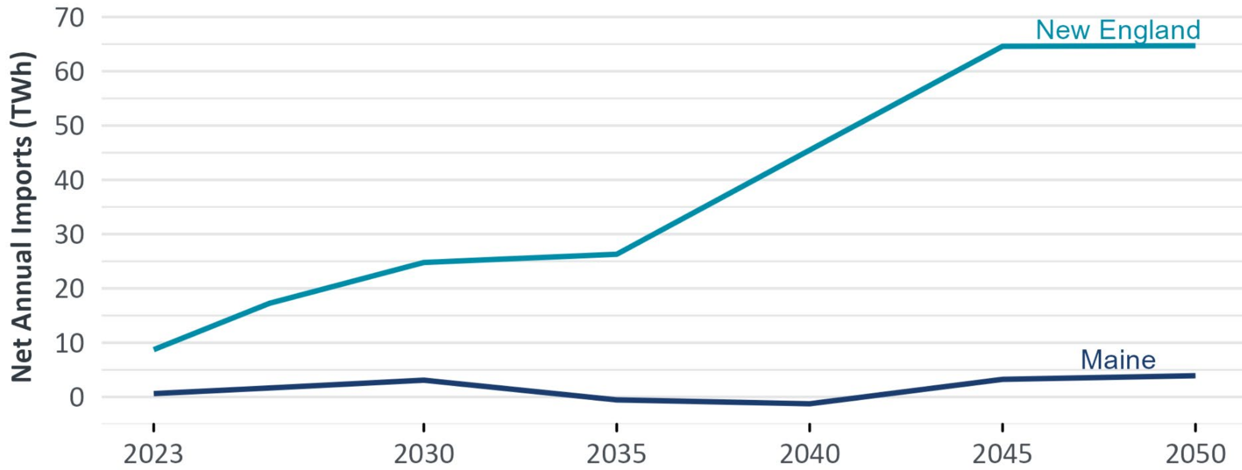
system has relatively less offshore and onshore wind capacity (19% in New England vs 46% in Maine), more solar (36% in New England vs 19% in Maine), and more storage capacity (10% in New England vs 5% in Maine). Similar to Maine, the New England system maintains significant thermal capacity, while utilizing it infrequently during periods of especially low renewable energy generation and high demand, particularly in the winter when electricity demand for space heating peaks. While fuel usage for thermal resources decreases over time in New England, the fraction of electricity generation obtained from thermal resources remains higher than in Maine. This is largely due to the difference in timing of states' GHG reduction and clean energy goals. By 2050, the New England system has largely decarbonized, as most states across the region converge on their GHG reduction requirements.

Additionally, both Maine and New England import electricity to balance the grid when energy production from renewable generation is inadequate to meet demand. Figure III-9 shows the net annual electricity imports to Maine and New England. Net imports to Maine peak at just under 4 TWh in 2050, representing 14% of electricity demand within the state.[79] Across New England, net imports rise through 2050, peaking at just under 65 TWh in 2045 and 2050 (approximately 25% of electric demand).[80] Most of these imports come from Canada, with a small portion (around 5 TWh) coming from New York State. The model ensures that even while providing energy to New England when needed, these neighboring regions also meet their own loads reliably and economically.

79 In 2030, imports hit just over 3 TWh, representing 20% of electric demand within the state, before falling into the negative regime (net exports) in the 2030s as in-state production of wind power picks up. By comparison, net imports only equaled 5% of total electric demand in 2023.

80 In 2023, New England electricity demand was about 130 TWh, of which imports represented 7%.

FIGURE III-9: NET ANNUAL ELECTRICITY IMPORTS IN MAINE AND NEW ENGLAND, CORE PATHWAY



b. Maintaining System Reliability

While renewable generation can cost-effectively serve electricity demand for the majority of the hours in the year, the high reliance on intermittent renewable generation in 2040 and beyond means that there will be hours in which total renewable generation alone is less than demand. This will happen on a near-daily basis, usually for a few hours at a time—often during evening hours when gross load is relatively high and solar output has fallen off. However, there will be other hours when renewable generation exceeds demand. For that reason, most of the periods of shortfall can be addressed with a combination of flexible load and storage technologies—hydropower and pumped hydropower from existing resources, including from Canada, and shorter-duration (1–8 hours) batteries.

The primary engineering challenge of achieving Maine's 2040 greenhouse gas reduction and clean electricity goals is finding a cost-effective approach to meeting electricity demand when renewable output falls far short of load for extended periods, typically in winter. These shortfall hours amount to only a few percent of total electricity demand, but they are crucially important as they cause a high "net" peak ("net" referring to the difference between hourly load and hourly renewable production). This net peak will be the primary driver of future reliability and capacity needs, a departure from today where gross peak demand drives most capacity needs. Net peak does not necessarily coincide with the system's gross peak; it tends to occur in winter during extended periods of limited solar and wind output. While load flexibility, hydropower, and battery resources do help in these periods, they are not sufficient to cover the extended winter shortfalls that can occur.

In the Core pathway, the remaining gap in these extended winter periods is met by a combination of transmission imports (predominantly Canadian hydropower) and dispatchable thermal generators (such as existing combined cycle plants) utilizing carbon-neutral fuels such as hydrogen, biofuels, synthetic fuels, and potentially fossil fuels to generate power.

Thermal resources provide inter-annual flexibility; they only need to be operated when there is an extended shortage of renewable generation, which may not occur at all in some years. The generating capacity is relatively low cost to develop and keep on standby, and it is used in much the same way as it is used to serve summer peaks today. Further, much of this capacity is already installed, so its capital cost is effectively a sunk cost, at least for the horizon of this analysis.

System Flexibility

Figure III-10 shows the relationship between end-use load in Maine and in-state generation from variable renewables, including hydropower, solar, and wind (onshore and offshore) over a 3-day period in January of 2050. during the first two days, renewable generation is roughly sufficient to satisfy demand, with some excess midday solar available for export, and some reliance on storage in shortfall hours. On the third day (Jan 25), wind and solar generation both drop off, leaving a sizable gap between supply and demand.

Figure III-11 illustrates the active dispatch of just the flexible energy resources during the same 3-day period. Positive values represent increased supply and/or imports and negative values show consumption and/or exports. In the first few hours illustrated, the shortage of supply is satisfied through a combination of thermal generation, storage withdrawals, and transmission imports. Over the following two days, when there is an abundance of supply (particularly in the afternoons), the excess energy is either exported to other states or used for opportunistic loads, including for producing carbon-neutral fuels using electrolysis. On the last day when renewable generation drops off, the large and sustained gap is filled by a combination of thermal generation and transmission imports, predominantly of Canadian hydropower. Storage plays a relatively small role due to its limited capacity (it would not be economical to build additional storage capacity, since it is costly and would be utilized only rarely).

FIGURE III-10: END-USE LOAD VS. NON-DISPATCHABLE RENEWABLE GENERATION OVER 3-DAY PERIOD, CORE PATHWAY

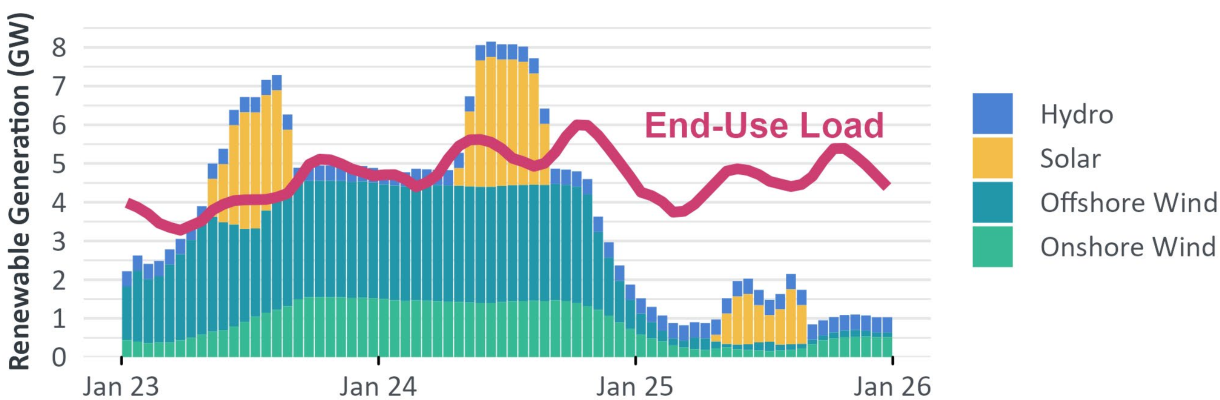


FIGURE III-11: RESOURCE OPERATIONS DURING 3-DAY PERIOD WITH LOW RENEWABLE ENERGY OUTPUT, CORE PATHWAY

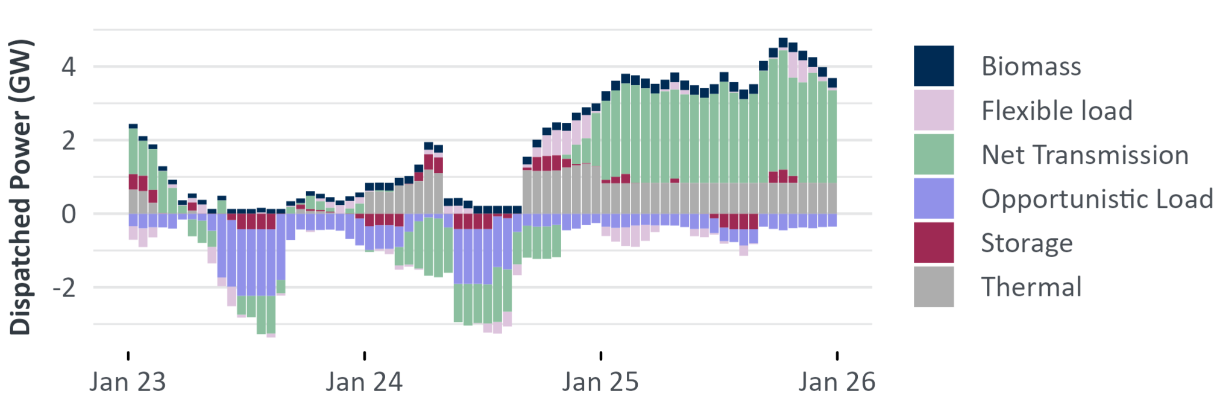
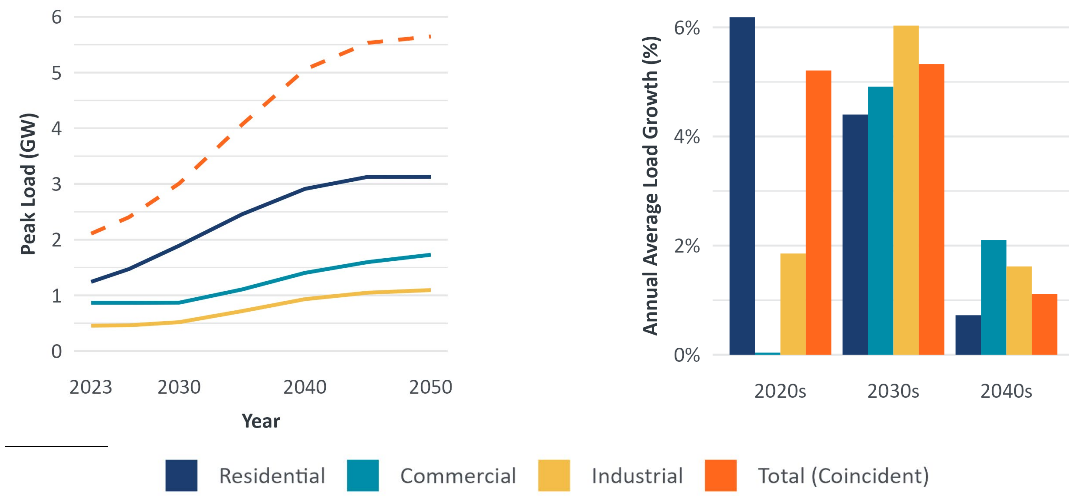


FIGURE III-12: ELECTRIC DISTRIBUTION SYSTEM PEAK LOAD IN MAINE AND ANNUAL LOAD GROWTH BY SECTOR, CORE PATHWAY



Note: Solid lines represent the *non-coincident* peak loads for residential, commercial, and industrial sectors (the peaks occur at different times). Transportation charging loads are allocated to the sectors depending on where charging occurs. The dashed orange line represents the total *coincident* peak load, which is slightly less than the sum of the individual non-coincident peaks.

The system ultimately requires even more than the current fossil-fueled thermal capacity; while no new thermal resource capacity is added in the 2020s, thermal additions begin in the 2030s in Maine and New England. Until then, Maine and the broader New England region can determine the amount of thermal generation to retain and/or build while developing other components of the region's reliability infrastructure. The extent of thermal capacity additions will depend on how key factors such as fuel costs, storage costs, and renewable installation levels develop in the next decade.

The carbon-neutral fuels themselves are likely to be relatively costly. The supply of biofuels may be limited, and synthetic fuels are currently much more expensive than fossil fuels, though prices are likely to moderate somewhat as technologies improve and production increases over the coming decades.[81] But since these thermal generators will operate only a very small share of the time, their fuel consumption would be comparatively low. By 2050, the fleet of fuel-burning generators across New England is expected to operate at just under 5% of the time on average, compared to 39% in 2026.[82] It will be important to ensure that these advanced fuels are truly low-emission and sustainable, or at least to clearly understand and offset any emissions. Since utilization is very low, the environmental impacts from burning these fuels is likely to be modest, particularly in relation to current impacts.

[81] For a more detailed discussion of carbon-neutral fuels, see Dean Murphy and Weiss, Jurgen, "Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050," n.d. and Kwok, Gabe, "Low Carbon Fuels in Net-Zero Energy Systems," August 2022.

[82] For comparison, Figure III-7 above shows the modeled capacity factors for different types of generation in Maine in 2026 and 2040. The capacity factor of the thermal fleet in Maine is generally lower than that of New England, indicating that Maine's thermal assets are utilized more sparingly than those of the broader region.

c. Electric Transmission and Distribution

Upgrades to the Maine and New England distribution and transmission systems will be a key enabler for achieving Maine's clean energy and greenhouse gas reduction goals.[83] There will be two primary drivers of distribution and transmission expansion. First, the higher electricity demand that accompanies widespread heating and transportation electrification will increase overall peak loads on the distribution and transmission system. Second, transmission upgrades will be necessary to interconnect new renewable generation, establish new and higher-capacity links with neighboring systems, and move power across new and expanded routes. Distribution and transmission planning must incorporate future load and flow projections to ensure that the system is cost-effectively expanded to meet load and reliability needs.

The distribution system that delivers power to retail customers will need to expand to accommodate growth in electricity demand due to the increased adoption of electric heat pumps and EVs (Figure III-12). The largest growth in distribution capacity is to support the residential sector, with near-term annual peak load growth of about 6% per year due to the increasing electrification of space heating.[84] In the 2030s, annual average peak load growth is consistently in the 4–6% range across sectors due to widespread electrification across the economy, before dropping below 2% per year in the 2040s.

The Core pathway assumes a 'Medium' level of load flexibility, where flexible load, i.e., demand that can be shifted in time to work around the stresses on the grid, can moderate distribution system growth to some extent.[85] New electrification loads, especially EV charging, are inherently flexible, since charging load can be scheduled at any time the vehicle is not in use and is plugged in. This can reduce the amount of incremental electricity infrastructure necessary at several levels—generation, storage, transmission, and distribution—thus mitigating costs substantially. For example, smart EV charging can shift much charging load to overnight hours when other loads are low. This load flexibility will limit the need for infrastructure expansion and thus moderate cost impacts. To capture the benefits of load flexibility, distribution planning processes will need to account for the impacts of load flexibility and other distributed generation resources, including behind-the-meter solar and storage installed by residential and commercial customers.

Significant transmission capacity expansion will be necessary. Future transmission system needs include local upgrades to accommodate load growth, upgrades to the transmission system to access new generation resources in Maine (including onshore and offshore wind), and upgrades between Maine and its neighbors to integrate new generation resources into the ISO-NE system and connect to Canadian hydropower. The scale and costs of transmission upgrades can be mitigated by proactively planning the system to identify least-regrets upgrades and incorporating cost effective alternatives, including grid-enhancing technologies (GETs), simple remedial action schemes

83 This study differentiates between lower voltage, radial systems that primarily serve demand as the distribution system and the higher voltage, meshed system that is integrated into the New England-wide ISO-NE system and connects generation resources to demand as the transmission system.

84 Commercial heat pump adoption also occurs in the 2020s but does not initially increase annual peak demand because commercial demand currently is summer peaking. Commercial peaks begin to increase in the 2030s, due to a combination of heating electrification and electric vehicle charging.

85 The impacts of different assumptions about flexible load and distributed resources on the electric distribution system are explored in the High Flexible Load and No Flexible Load pathways.

(RAS), and advanced conductors, into the planning process.[86]

- **Local transmission upgrades to meet rising peak load**: Local upgrades, especially in southern Maine, will be necessary to serve rising demand. Maine will need to add 3 GW of transmission capacity to its local system through 2040 via upgrades of its existing system and new transmission facilities to serve rising in-state demand. In addition, Maine will need to continue to maintain and upgrade aging transmission infrastructure.

- **Transmission to interconnect offshore and onshore wind resources to the existing system**: Injecting 3 GW of offshore wind in Maine will require investment in offshore infrastructure, including: offshore substations, subsea cables connecting to the onshore system, and upgrades to the existing onshore transmission system to accommodate the increased flows. Similar investments will need to be made throughout New England and elsewhere. In addition, following the cancellation of the Aroostook Renewable Gateway project, a similar or higher capacity transmission upgrade will be necessary to access at least 1.2 GW of northern Maine onshore wind.[87]

- **Regional transmission upgrades to integrate renewable energy resources**: Regional upgrades will be needed to increase capacity to exchange power between Maine and the rest of New England, and to serve Maine electricity demand with a geographically diverse and cost-effective set of clean resources. In collaboration with other New England states, Maine will need to add 4.6 GW of transmission capacity between its load centers and other regions by 2040. ISO-NE similarly identified the corridor from southern Maine to Boston as a "High-Likelihood Concern" in its recently released 2050 Transmission Study, estimating the cost of required upgrades to be $5.0-6.5 billion through 2040.[88]

3. Cost Implications

a. Energy Supply Costs

Today, electricity system-related costs, including generation, transmission, and distribution costs, represent about 40% of Maine's total cost of energy supply. The remainder of the supply costs (at about $3.9 billion) stem from fossil fuels such as diesel, gasoline, heating oil, and natural gas (including their delivery costs).

To achieve economy-wide greenhouse gas reduction goals, fuel purchases decline, while costs in all categories of electricity infrastructure increase (increasingly dominated by upfront capital costs, since fuel costs are zero for renewable generation). Much of the increased cost associated with electrification and new renewables development is offset by decreasing fossil fuel costs. As a result, total supply costs remain relatively similar over time, though the composition changes as energy needs and generation resources evolve (Figure III-13, left panel). The pathways analysis, presented in the following section, shows how costs are affected by the specific choices this study makes about *how* to eliminate GHG emissions and achieve clean energy goals in the context of evolving technologies and markets.

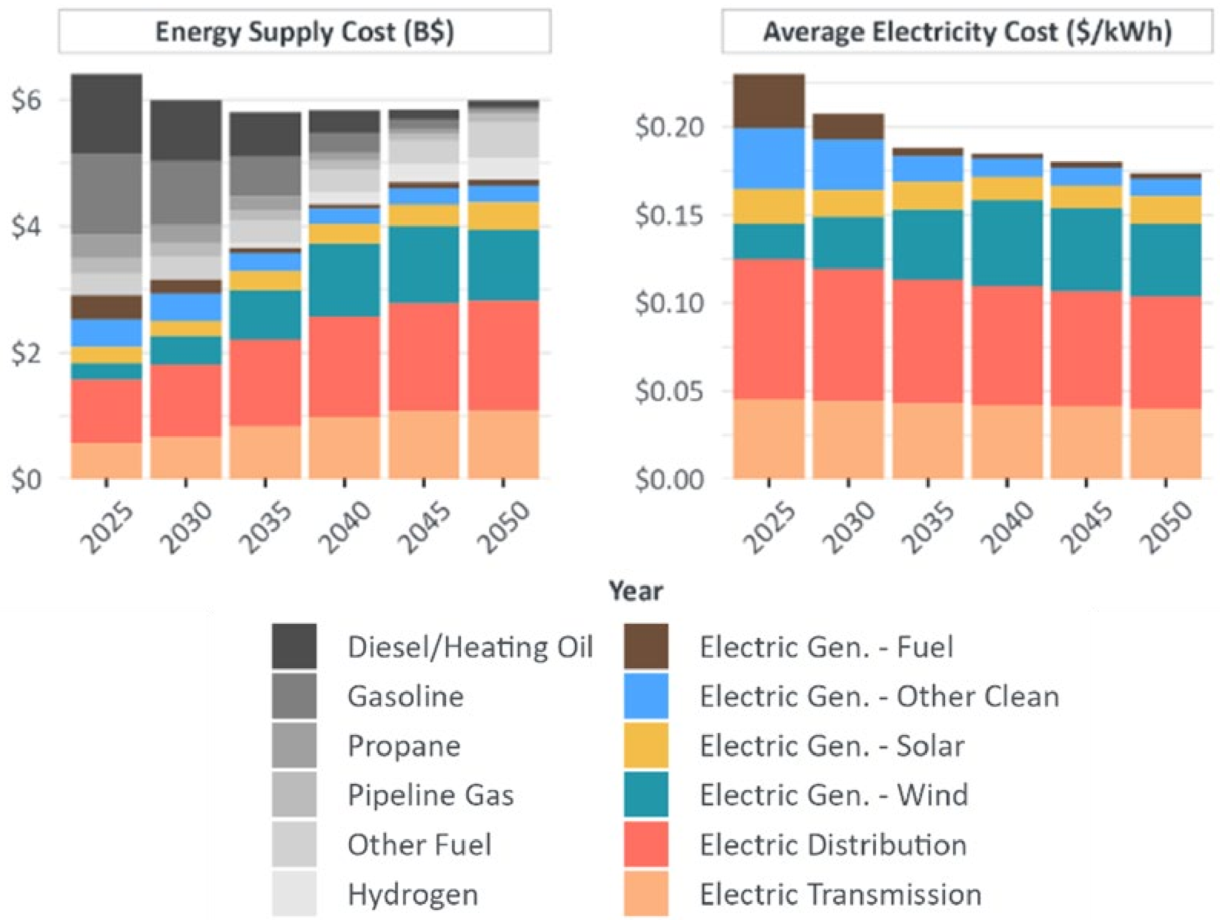
---

[86] Tsuchida, T. Bruce, et al., Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts, Prepared for WATT Coalition, April 20, 2023.

[87] Maine and Massachusetts planned to share the costs of increasing transmission capacity to northern Maine via ARG and may pursue a similar arrangement in the future to support transmission development to northern Maine onshore wind.

[88] ISO New England Inc., 2050 Transmission Study, Transmission Planning, February 12, 2024.

FIGURE III-13: ENERGY SUPPLY COSTS AND AVERAGE SOCIETAL ELECTRICITY COST FOR MAINE, CORE PATHWAY (2022$)



Note: Energy supply cost is determined for all categories based on Maine's consumption. The average electricity cost is computed by dividing the cost of electricity supply shown on the left by the total volume of electricity consumed in Maine. The "Other Fuel" category includes steam, kerosene, jet fuel, biomass, ammonia, and other petroleum costs.

Within electricity, the most significant growth is seen in electric distribution costs, which increase from about $1 billion per year in 2025 to $1.74 billion per year in 2050 (amortized).[89] As discussed above in the Electric Transmission and Distribution subsection, this growth is driven primarily by the rise in peak loads on the distribution system, prompting new investments for its expansion. While a large portion of distribution costs scale with increasing peak load, a sizable portion remains essentially fixed.[90] As a result, the total distribution system costs rise less quickly than the distribution peak.

Even though the total cost of supplying electricity is expected to grow over time, the volume of sales is

[89] Note that there is uncertainty in these estimations even in the short term due to inflation and supply chain issues. There is also uncertainty due to the high-level assumption used in the study to project distribution costs, where 60% of distribution cost is assumed to scale with peak and the remaining 40% is fixed, based on analysis of utility costs conducted by EER. Actual costs will depend on how individual cost components evolve over time.

[90] These non-peak related costs are associated with serving customers, and include metering, billing, and a portion of the costs incurred for poles and power lines.

expected to outpace this growth.[91] Consequently, the average cost of electricity is expected to fall (Figure III-13, right panel).[92] As electrification accelerates, a portion of EV charging is shifted to periods of lower grid utilization (enabled in part by the timing flexibility assumed for EV charging loads, discussed in detail later). This moderates the growth in peak load as electricity sales increase in the long term. The average per-kWh electricity price declines steadily through 2050 as electrification gains momentum and demand growth exceeds the growth in costs.

Natural gas system costs (shown as "pipeline gas" in Figure III-13) represents a small portion of the overall energy supply costs in Maine.[93] While natural gas is not widely used for home heating in Maine (only about 1 in 12 homes rely on natural gas), it is an important fuel source for commercial and industrial customers. Total gas system costs decline only slightly over time as more customers adopt electric heating, reducing their gas usage or departing the gas system altogether.

However, this means that gas delivery costs, which are largely fixed, will be spread over a declining customer base with falling total sales. This will likely lead to higher average unit costs and higher bills for remaining customers (gas ratemaking and thus customer bill impacts may change in response to these forces). The cost of carbon-neutral fuels, which may be necessary to achieve the necessary emission reductions in the gas system, may introduce additional uncertainties regarding future gas system costs.

As the consumption of fossil fuels (diesel, heating oil, gasoline, and propane) decreases over time, their total cost falls, while clean fuel costs increase with their rising consumption. By 2050, hydrogen represents about a third of the fuel costs shown in Figure III-14. These transitions lead to a shift in energy

What is Included in Energy Supply Costs?

Energy supply costs cover the commodity costs of fuels and electricity, where electricity costs include generation capital costs as well. Energy supply costs also include delivery costs, based on the embedded costs of building, maintaining, and operating infrastructure such as electricity transmission and distribution systems, and pipeline gas delivery networks.

These costs are measured from a societal perspective, rather than from the perspective of a particular supplier or a customer. As such, cost transfers within society, such as generator profits, are not included, since they do not reflect a net cost. The study uses the terms cost, expense, and spending interchangeably.

The analysis does not attempt to quantify the damages from climate change, or any abatement of those damages. Relatedly, the co-benefits of pursuing a net-zero emissions policy for Maine or the region, such as employment and public health benefits, are not quantified in this analysis.

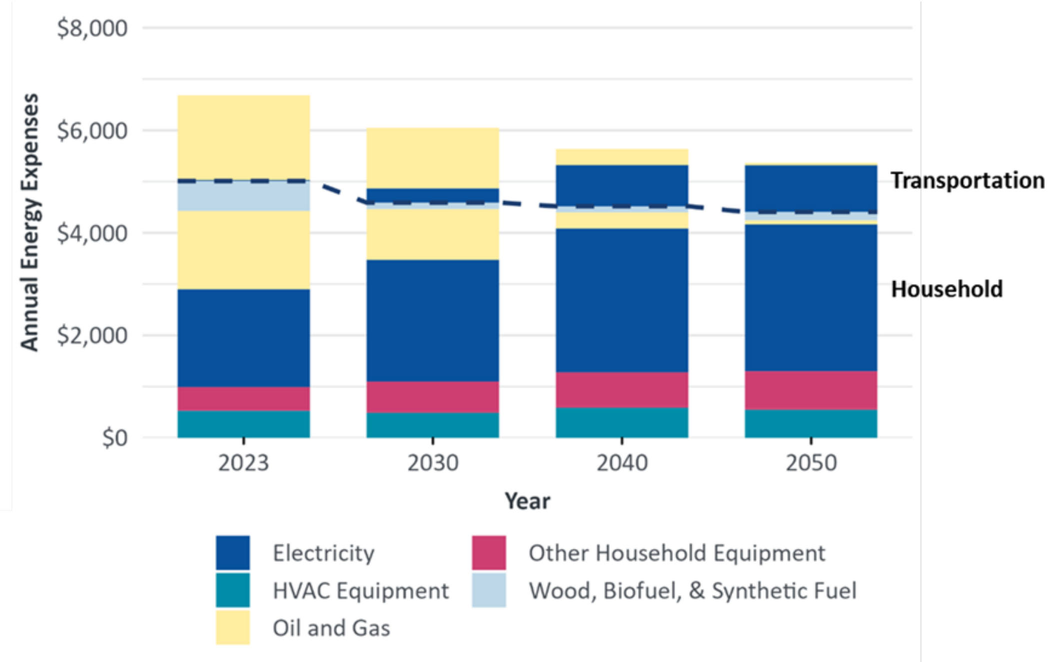
---

91 Per Figure 15, electric sales more than double by 2050.

92 This average cost differs from retail rates. It reflects the average of all customer classes, not just residential customers. Some bill costs, such as program costs, are not included, and generator profits are not included since they reflect a cost transfer, not a net cost. Still, the average is a useful metric for comparing pathways.

93 "Pipeline gas" does not include the cost of natural gas used for electricity generation. The cost of natural gas used for electricity generation is shown under "Electric Generation – Fuel" category.

FIGURE III-14: AVERAGE ENERGY EXPENSES FOR A MAINE HOUSEHOLD, CORE PATHWAY (2022$)



Note: Average energy-related expenses for a household in Maine from 2023 to 2050, including all household energy, household equipment, and transportation energy expenses. For each bar plot, the area below the black line describes household energy expenses and the area above the black line describes transportation energy expenses. Eighty percent of light-duty transportation costs are allocated to households, and the remainder to commercial uses. Vehicle purchase costs are not included here, as they are not strictly energy expenses. While there is currently a price premium for electric vehicles relative to ICE vehicles and hybrids, they are expected to reach cost parity by around 2030. See Section IV: Key Policy Implications for additional discussion on individual technologies.

costs, away from fossil fuel purchases and towards electricity (and new demand-side equipment, not shown in this figure). Demand-side spending includes purchases to adopt EVs and heat pumps, and to implement energy efficiency measures. These substantial upfront costs may present a barrier for some customers. This is discussed in Section IV: Key Policy Implications.

b. Changing Energy Wallet

Changing energy supply costs have a direct impact on customer energy bills. Figure III-14 shows the "energy wallet" (annual energy expenses for home and transportation) for an average household in Maine. Note that this shows the average costs across all Maine households, not the cost for a single Maine household.[94] As customers electrify their vehicles and home heating equipment, spending on oil and gas products falls, ultimately by over 90%, while spending on electricity increases, nearly doubling from 2023 to 2050 (from approximately $2,000 per-year to $3,800 per-year). This metric takes into account changes in the prices of different forms of energy, as well as changes in consumption of those different energy forms as customers transition away from fuels to

[94] These estimates are computed as the total residential energy costs divided by the total number of residential customers in each year. At any point along the graph, the wallet illustrates the average across all customers – some of whom have electrified heating and/or transportation, and others who have not.

largely electrified transportation, heating and other applications.

The total cost of serving the energy needs of an average Maine household falls by about 20% from 2023 to 2050 (just over $1,300 per-year), relative to 2023 costs. Both home and transportation energy costs are projected to fall as end uses powered by fossil fuels are transitioned to lower cost renewable electricity. It is important to note that the starting year, 2023, represents relatively high prices for both electricity and heating fuels. Residential electric rates in Maine have nearly doubled in the past two years, from 16.5 cents per-kWh in 2021 to 28.7 cents per-kWh in 2023.[95] Likewise, heating oil prices, which fell during the pandemic to just under $2 per-gallon, have since rebounded, reaching nearly $6 per gallon at the end of 2022 and leveling off at just under $4 per gallon in 2023.[96] Together, these trends have significantly increased energy costs for Maine customers over the past two years.

In addition to reducing energy costs relative to their recent high levels, the transition to a clean energy system can help hedge against future price volatility. Current energy costs are driven largely by the price of fuels—directly for gasoline, heating oil, etc., and indirectly for electricity, the price of which in New England is typically determined by the price of natural gas. Fuel costs have historically been and continue to be highly volatile. The cost drivers of a low-carbon energy system, in contrast, depend very little on fuel prices. System costs become increasingly dominated by up-front capital costs, such as the costs to develop renewable generation capacity and install heat pumps. As clean energy infrastructure is developed, Maine residents will be more insulated from the global fuel price volatility that has historically burdened customers in the state.

B. Key Observations for Other Pathways

This section presents results from the study's comparative pathways analysis. Each of the alternative pathways, described in the Pathway Modeling Approach section above, is designed to explore specific key questions about the transition to renewable and clean energy:

- The value of retaining thermal generation capacity past 2040 to serve as a backup for intermittent renewable generation;
- The pros and cons of hybrid heating systems, which may mitigate electricity demand peaks caused by extreme cold weather but also result in higher equipment and fuel costs;
- The role of load flexibility in managing the hourly matching of demand and supply; and
- The role of distributed energy resources in the clean energy transition.

Results from these pathways are discussed below, focusing on the key ways in which each differs from the Core pathway, and the insights that these differences generate. In most instances, the discussion focuses on the pathway differences across all of New England to best understand the results, since Maine is a part of the larger New England system and the operation of resources within any particular state may not reflect all the relevant impacts.

---

95 This is driven predominantly by increased supply costs (higher natural gas prices drive up wholesale electricity prices); distribution and public policy costs have also increased. Source: Maine Governor's Energy Office. "Electricity Prices." Accessed April 2, 2024.

96 Maine Governor's Energy Office. "Heating Fuel Prices." Accessed April 2, 2024.

1. 100% Renewable Generation Pathway

- Absent thermal generation, electricity system reliability could still be maintained, but it would require very large amounts of long-duration energy storage, more renewables and more transmission, resulting in materially higher energy supply costs.
- Maintaining dispatchable thermal generation and fueling it with carbon-neutral fuels enables affordable reliability.

The "100% Renewable Generation" pathway explores the role thermal generation plays in maintaining reliable electric service by modeling a counterfactual case wherein all fuel-burning generation is retired.[97] In this pathway, all thermal power plants are phased out by 2040 in Maine, and by 2050 across New England.[98] The primary challenge in this pathway is to maintain electricity system reliability in the absence of this dispatchable thermal generation. It is possible, but to do so, it is necessary to expand investments in electricity storage, develop additional renewable generation (grid-scale solar, onshore wind) to charge this storage, and increase imports of Canadian hydropower.

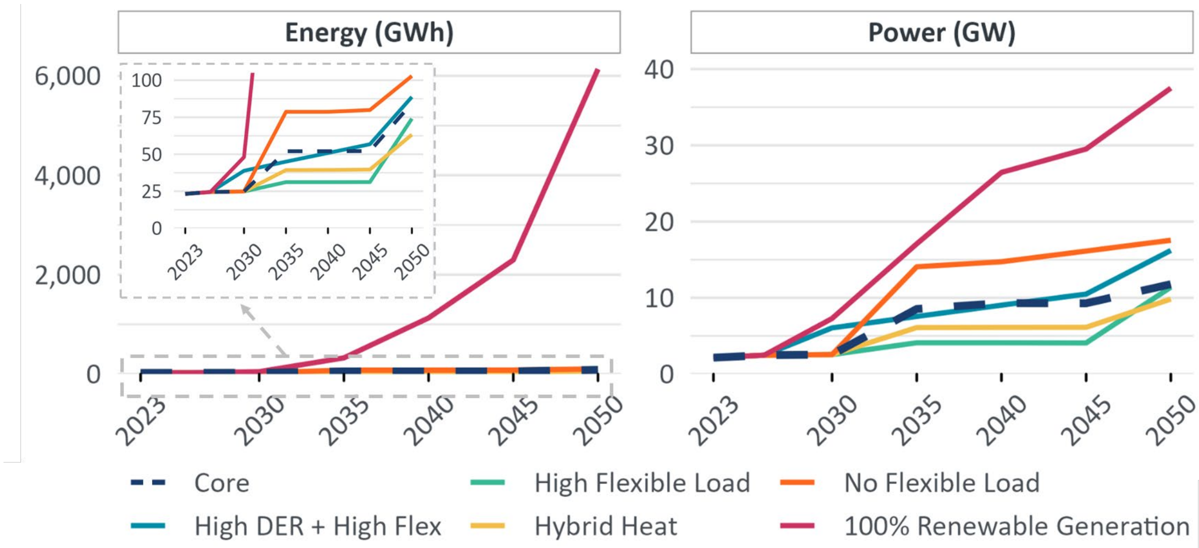
As shown in Figure III-15, New England electric storage reaches almost 38 GW (over 6,000 GWh of energy storage capacity) in the 100% Renewable Generation pathway by 2050, driven primarily by additional long-duration energy storage (LDES). This is about 60% of New England's 2050 peak load, and over a week's worth of average load. This is much more than the storage in the Core pathway, where the storage needed is 20% of peak and just 2.4 hours of average load (12 GW and 84 GWh by 2050). The story is similar for resources located within Maine; the 100% Renewable Generation pathway requires about four times as much storage in terms of power capacity, and 50 times as much in terms of energy, relative to the Core pathway.

Comparing the 100% Renewable Generation and Core pathways shows that without thermal generation as a backup resource, New England customers must rely almost exclusively on storage to provide bulk energy during long stretches with low renewable production. While the Core pathway utilizes small amounts of storage for short durations where load exceeds renewable generation for a few hours, it relies on thermal resources to meet longer duration energy needs and high winter peaks, since thermal generation can operate continuously for as long as fuel is available.

[97] In the Core pathway, both in Maine and in New England as a whole, thermal electric generation capacity is retained but provides a diminishing share of electric energy. This fuel-fired thermal generation is a key enabler of reliability on an electric system that depends largely on intermittent renewable generation, along with other enablers such as electricity storage, imported Canadian hydropower (which is both clean and highly dispatchable), and end-use flexibility. To meet Maine's 100% clean electricity goal, this thermal generation must burn a "clean" fuel such as hydrogen to cover at least Maine's share of demand (not all New England states have a 100% clean requirement, so some fossil fuel use continues beyond 2040).

[98] Here, "thermal generation" refers to combustion-driven thermal generators such as those burning fuels such as natural gas, fuel oil, or their clean counterparts, as well as nuclear. Biomass generators are not phased out. Existing New England nuclear plants are assumed to operate through the 2040s and retire by 2050.

FIGURE III-15: ENERGY STORAGE CAPACITY IN NEW ENGLAND, ALL PATHWAYS



Note: The required capacity of energy storage in the 100% Renewable Generation pathway is about 50 times higher than in the other pathways (left). The inset on "Energy" graphic expands the vertical scale to illustrate other pathways.

To address this longer-duration need without thermal plants, the 100% Renewable Generation pathway requires very large amounts of LDES. In fact, LDES replaces thermal nearly one-for-one on a power capacity basis: the additional 26 GW of storage in this pathway replaces 30 GW of thermal in Core. The incremental energy delivered by storage in 2050, above what is delivered in the Core pathway, is about 28,000 GWh, which is about twice as much as is generated by thermal resources in Core.

On top of the additional storage needed, more renewable generation is also developed, largely because it is needed to charge the additional storage. Relative to the Core pathway, the 100% Renewable Generation pathway requires 75% more onshore wind and twice as much offshore wind; it also increases utility-scale solar by 20% by 2050 and adds much of it earlier (see Figure III-16). A similar result is seen within Maine, where this pathway involves considerably more renewable resources—primarily offshore wind.

Despite serving similar functions, the additional storage (and incremental renewables to charge it) in the 100% Renewable Generation pathway results in considerably higher costs than the thermal resources in Core, leading to higher overall energy supply costs. Most of this additional cost comes from energy storage and renewables, as well as greater electric transmission needs to support the additional renewable generation.

In addition to being costly, the need for so much more renewable generation also increases transmission requirements for interconnecting the additional renewable resources and moving the power to load. This includes increasing the transmission capacity between Maine and Quebec from the 1.2 GW planned as part of the New England Clean Energy Connect (NECEC) to nearly 5 GW by 2050. In aggregate, the electric transmission capacity between Canada and New England must increase from 2 GW at present to 12.3 GW in 2050 in the Core pathway; in the 100% Renewable Generation Pathway, this capacity must increase to 16.5 GW by 2050.

Key Resources on the Homestretch to Achieving 100% Clean Electricity

Over the next decade, the Maine and New England electric power sector will reduce its GHG emissions through the accelerated development of renewable energy and short- to mid-duration energy storage (2-10 hour duration) resources, driven by policies and resource economics. During this period, dispatchable generation resources, primarily natural gas-fired thermal generation and imports, will continue to fill in the remaining gap between clean energy supply and electricity demand as it varies throughout the day. This analysis highlights that GHG emission reduction goals will limit the ability for natural gas-fired resources to fill this gap, and will require additional clean electricity resource types in the late 2030s and 2040s to balance hourly supply and demand, especially during extended periods of low renewable energy generation.

Based on technology availability, operating characteristics, and costs, there are two primary resources that currently demonstrate the most promise to support Maine in the homestretch to 100% clean electricity:

- ***Clean thermal resources*** include gas-fired generation resources (e.g., gas turbines and combined cycle plants) that will burn carbon-neutral fuels such as renewable natural gas or hydrogen, instead of natural gas. These resources are very similar to existing thermal generators, and in fact, it may be possible to modify existing generators to fulfill this role. However, the ability for these resources to play a key role in the future power system depends on whether carbon-neutral fuels are produced at sufficient scale to meet the demands of the power sector as well as other end-uses aiming to reduce their emissions (e.g. heavy-duty transportation and industrial process heat).

  In the Core pathway, thermal electricity generation capacity in Maine and New England increase modestly as clean thermal resources are found to be the most economic approach to meeting the needs of a deeply decarbonized system, but switch from natural gas to carbon-neutral fuels by 2040 and ultimately operate at less than 5% capacity factor.

- ***LDES resources*** include storage resources that can sustain their output over a longer period than current lithium-ion battery storage technologies, at least 12 hours (inter-day LDES) and in some cases over 100 hours (multi-day LDES). Currently, pumped storage is the primary form of LDES available in the ISO-NE market. LDES is attractive due to its lower projected costs per-unit of energy storage capacity (i.e., costs per kWh) relative to lithium-ion batteries, but it tends to have much lower round-trip efficiency (40-50% compared to 80-85% for lithium-ion), meaning that losses are much higher when stored energy is retrieved. Due to its low efficiency, the addition of LDES requires a significantly higher renewable energy buildout than would be needed with clean thermal generation. Although the technology has yet to be commercialized, several LDES developers are pursuing early-stage development and deployment of their technologies to scale up production and demonstrate its ability to meet the future system needs, supported by state, utility and federal LDES-specific programs. [99] Given these characteristics, LDES may be able to play a significant role in meeting the needs of a deeply decarbonized power system, especially in a future where access to carbon-neutral fuels is limited.

[99] For a list of DOE LDES pilot programs, see here.

FIGURE III-16: ELECTRICITY SUPPLY IN NEW ENGLAND IN CORE (LEFT) AND 100% RENEWABLE GENERATION (RIGHT) PATHWAYS

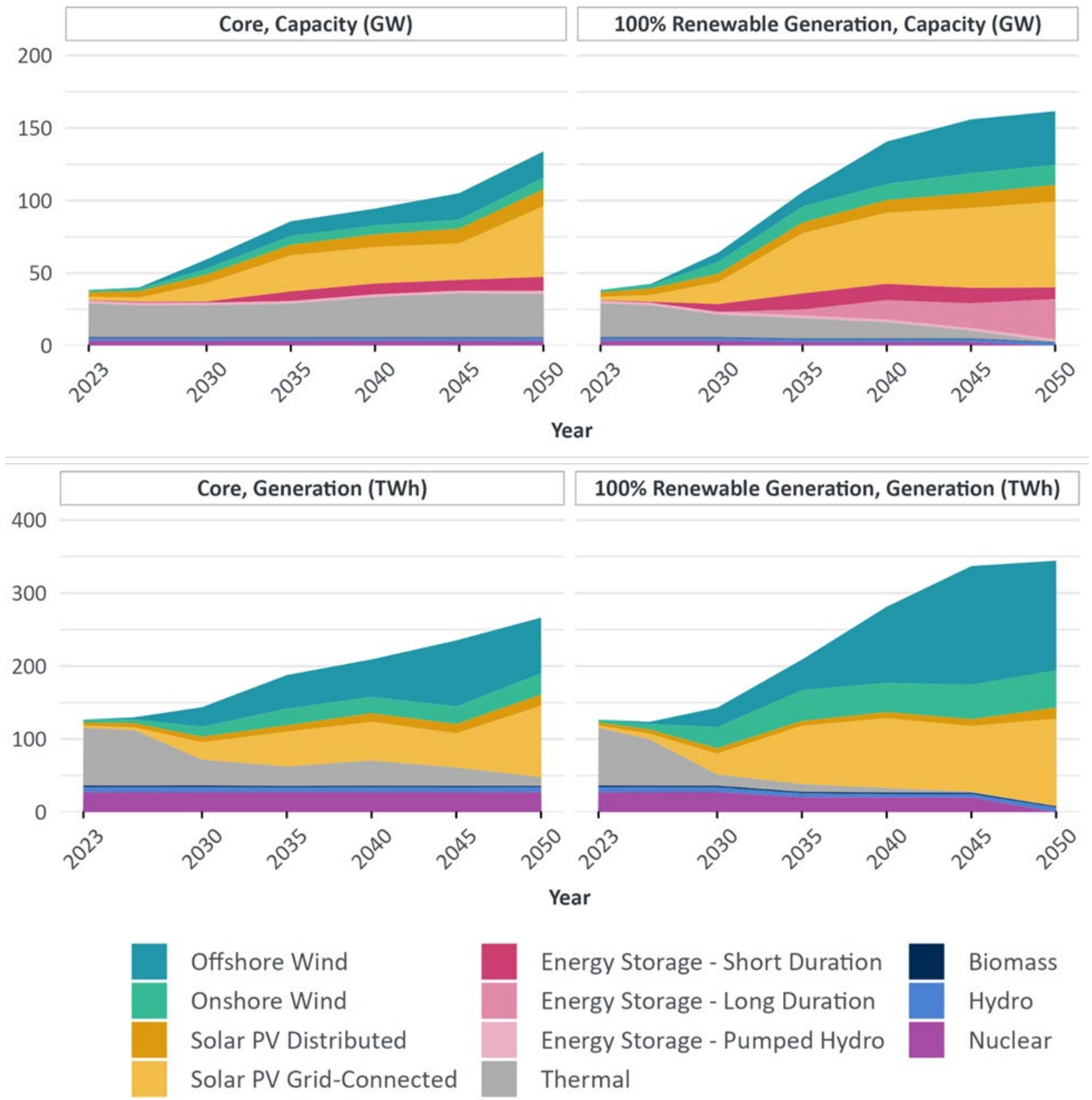
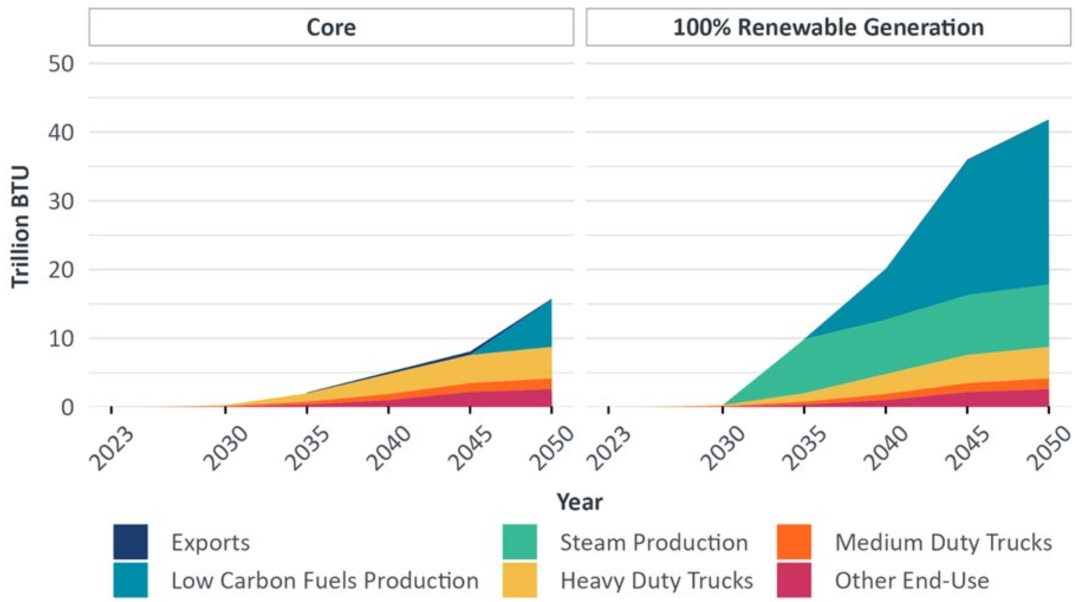


FIGURE III-17: HYDROGEN DEMAND IN MAINE IN CORE AND 100% RENEWABLE GENERATION PATHWAYS



Note: "Other End-use" represents various end-uses in the residential, commercial, industrial, and transportation sectors. "Exports" represent exports from Maine to other states.

Most of the incremental investments in the 100% Renewable Generation pathway are not incurred until 2035 and beyond, including investment in LDES.[100] LDES is still a nascent technology with considerable uncertainty about its future cost and performance. This indicates that Maine could retain its thermal generation capacity for now in anticipation of using it for backup generation, then, if economically feasible (i.e., if LDES is much less costly than anticipated), begin replacing thermal with LDES in the 2030s and 2040s. This approach, which could be applied more broadly to New England, keeps open the option to transition from backup fuel generation to LDES, without making early, irreversible, and potentially costly commitments to meet reliability needs.

In the 100% Renewable Generation pathway, the additional renewables required to cover occasional storage charging needs leads to surplus renewable generation in many other hours. This surplus generation is utilized by flexible electrolyzer loads as it is available, taking advantage of the surplus renewable output to produce hydrogen, while also providing a major source of system balancing. This allows the system to deliver more renewables to fixed loads economically and provides fuels that are useful in other sectors. As a result, Maine becomes an exporter of zero carbon fuel (e.g., ammonia) to other New England states (Figure III-17).

Due to the increased availability of cheaper clean fuels, cumulative fuels costs are lower in this pathway in the 2023–2050 timeframe, for both Maine and New England as a whole. This offsets only about 30% of the incremental electricity system costs, leaving higher overall energy supply costs.

[100] The 100% Renewable Generation pathway results in modest cost savings until about 2035, achieved by retiring thermal plants. However, as electrification continues to drive load growth, the inexpensive capacity provided by this thermal generation must be replaced by much more expensive LDES-plus-renewable solutions, which causes energy supply costs to jump between 2035 and 2040, relative to Core.

2. Hybrid Heat Pathway

- Backup fuel heating may mitigate peak electric loads and reduce electricity infrastructure costs, but electricity supply-side savings are largely offset by increased customer equipment costs.
- New technology and changes in customer behavior to enable co-optimization of separate building heating systems would be required to enable any customer or electricity grid savings.
- The Hybrid Heat pathway involves higher fuel demand for heating, which will need to be satisfied with a greater supply of biofuels and synthetic fuels in the long term.

While widespread heat pump adoption is essential to achieving Maine's greenhouse gas reduction goals, electrified space heating could contribute to steep winter electric peaks in the future.[101] The Core pathway finds that these space heating peaks are a significant driver of electricity infrastructure requirements in the long run, contributing to the need for increased distribution, transmission, and generation capacity.[102,103]

The Hybrid Heat pathway explores an approach to mitigate these heat pump peaks by maintaining fuel boilers in buildings that act as a backup source of heat when the ambient temperature drops below freezing (using clean fuels in the long term). These fuel-burning systems are dispatched on cold days, displacing the electric loads from heat pumps and thus avoiding some of the increased electric infrastructure needs. The Hybrid Heat pathway modeled cuts the residential space heating demand approximately in half, substantially reducing the

[101] Electric demand for space heating accounts for 30% of the electricity system peak in Maine in 2050 in the Core pathway (before implementing load flexibility), despite representing just 10% of total electric energy consumption.

[102] Space heating demand is highly correlated across a given region (if it is cold in Portland, it is likely to be cold in Bangor as well), leading to a simultaneous increase in demand. Moreover, air-source heat pump efficiencies fall as the outdoor temperature drops, which means that more electricity is needed to produce each unit of heat at precisely the times when the overall amount of heat needed is highest.

[103] Ground-source heat pumps, either installed individually for each home or networked together, might offer an alternative approach to mitigate electric peaks, because they maintain higher efficiency at low ambient temperatures. However, the excavation and/or drilling required to install these systems is still quite costly, often outweighing the operational savings they provide. Given the bespoke nature of deployment, ground-source heat pumps were not represented explicitly in the pathway modeling.

incremental electric distribution infrastructure required to support Maine through 2050 (Figure III-18).[104] In the Core pathway, Maine must increase distribution system capacity by 130%, from 2.6 GW to 6 GW; in the Hybrid Heat pathway, distribution capacity increases by only 87%, to 4.8 GW.[105]

Figure III-19 shows the relationship between Summer Peak and Winter Peak from 2023 to 2050 in the Core and Hybrid Heat pathways, for both Maine and New England. In Maine, in the Core pathway (left panel, solid lines), summer and winter peaks are comparable in the starting year, then diverge as winter load growth from heating electrification outpaces summer load growth.

The winter peak in the Hybrid Heat pathway (dashed teal line) grows more slowly than the winter peak in the Core pathway because heat pumps are not used as the primary heat source on colder days, when space heating demand is higher and air-source heat pump efficiency is lower. As a consequence, the winter peak in the Hybrid Heat pathway tracks much more closely to the growing summer peak. Across New England, where the climate is milder on average than in Maine, hybrid heating keeps the winter peak below the summer peak (Figure III-19, right panel).[106]

Additionally, the Hybrid Heat pathway results in lower thermal generation capacity needs compared to the Core pathway. Much of the thermal capacity that was being retained/added in the Core pathway was used to serve electric heating peaks. By effectively moving the combustion of clean fuels from remote power plants to homes and businesses, the Hybrid Heat pathway avoids the need for much of this generating capacity. In the Hybrid Heat pathway, thermal generation capacity is 36% lower in Maine (1.6 GW vs. 2.5 GW in Core) and 28% lower across New England (22 GW vs. 30 GW in Core).

While the Hybrid Heat pathway reduces spending on the electric system, it involves higher demand for heating fuels in homes, which will need to be satisfied by costly clean fuels in the long term to meet Maine's greenhouse reduction goals. This is seen in Figure III-20, which compares the energy sources used for space heating in the Core vs Hybrid Heat pathways. In 2050, the Hybrid Heat pathway results in the consumption of four times as much carbon-neutral heating oil, pipeline gas, and propane in homes and businesses.[107]

---

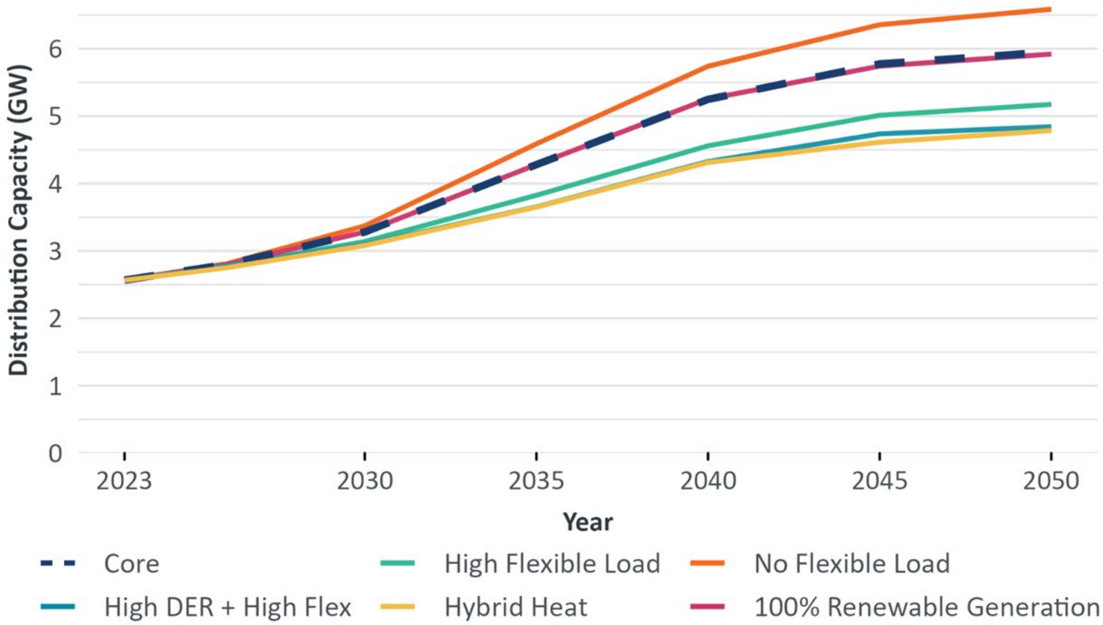
[104] The Hybrid Heat pathway analysis assumes that 50% of space heating demand is satisfied by heat pumps, with the remaining 50% satisfied by fuel-burning boilers/furnaces, using a 32F switchover temperature chosen to highlight the potential differences between the all-electric and hybrid heating approaches. This switchover temperature is not necessarily optimal; a heat pump could be sized to serve 80%-90% of heating load, with the fuel system operating only during the most extreme cold, which may decrease overall costs. Regardless of sizing, it is not guaranteed that heat pumps will be fully utilized if backup fuel systems remain, underscoring the importance of customer education and integrated controls. This is discussed in Key Policy Implications.

[105] This reduction in peak load also reduces the estimated long-term need for added intrazonal transmission capacity in Maine by 1.2 GW.

[106] Growth is heterogeneous across the region: some highly residential areas will have greater load impacts from heating electrification, while other areas that do not add substantial vehicle charging or heating electrification will see a much smaller impact.

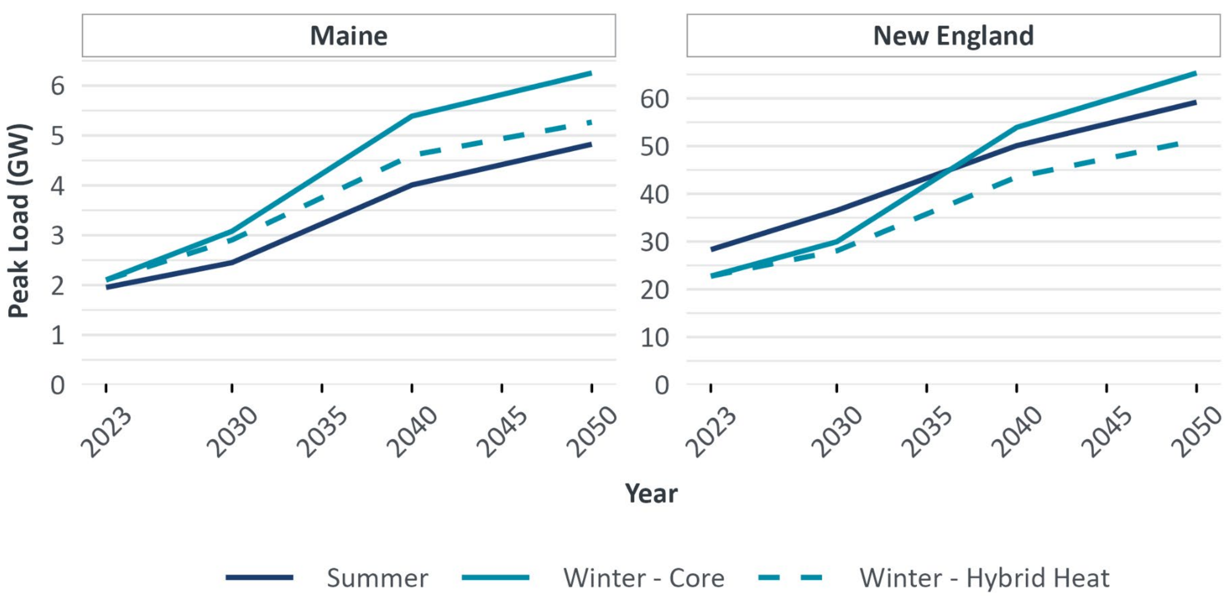
[107] Due to the much higher efficiencies of heat pumps over furnaces, primary energy used for space heating in both pathways falls by over 50% from 2023 to 2050. The key difference is that because the Hybrid Heat pathway relies to a greater extent on fuel on cold days, it uses about five times as much fuel for heating in 2050 (about 10 trillion BTUs, vs 2 trillion BTUs in Core) than the Core pathway, and about 30% less electric energy.

FIGURE III-18: TOTAL DISTRIBUTION SYSTEM CAPACITY IN MAINE, ALL PATHWAYS



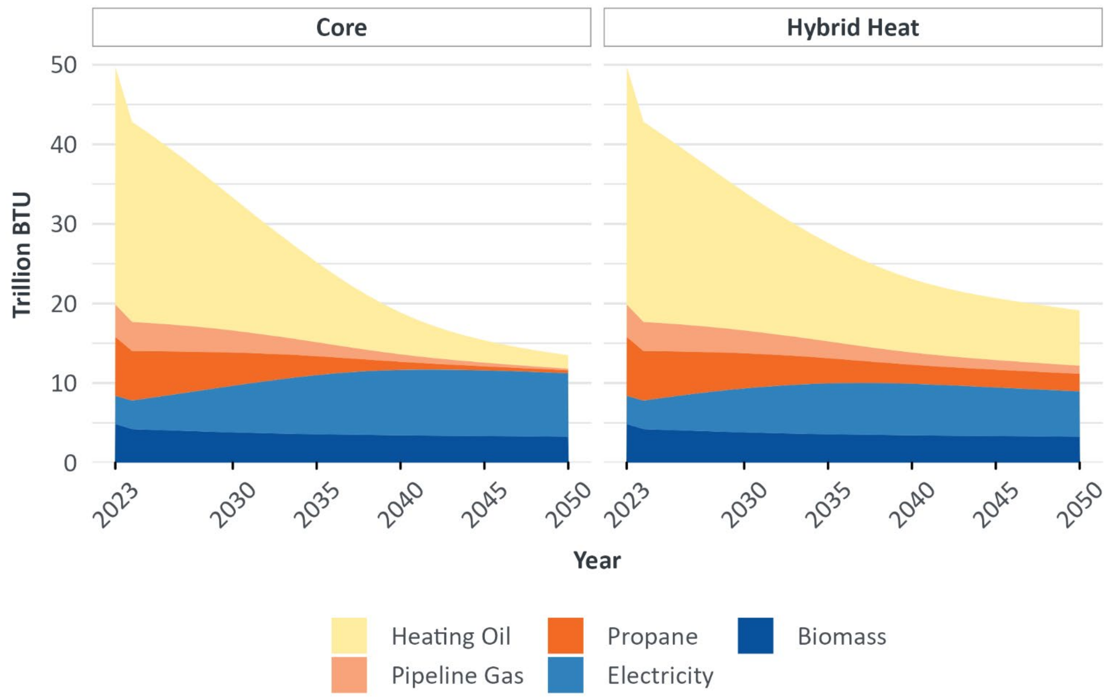
Note: The "100% Renewable Generation" pathway is behind the Core pathway as they are nearly identical on the demand-side. This results in very similar distribution system capacity growth curves.

FIGURE III-19: MODELED SUMMER AND WINTER PEAK LOADS BEFORE LOAD FLEXIBILITY, FOR THE CORE AND HYBRID HEAT PATHWAYS



Note: Figure shows the coincident peak electric loads in the summer and winter in the absence of load flexibility, grossed up by 5% to account for line losses. Load flexibility reduces coincident peaks in all pathways (except for "No Flexible Load"). The trajectory of pre-flex winter peaks for the "Core" pathway applies to all pathways except "Hybrid Heat," as these pathways all have the same underlying primary energy demands; pre-flex summer peaks are identical in all six pathways for the same reason (hybrid heating does not materially affect summer cooling).

FIGURE III-20: RESIDENTIAL AND COMMERCIAL SPACE HEATING ENERGY SOURCE IN MAINE: CORE VS. HYBRID HEAT PATHWAYS



Note: Energy source for residential and commercial space heating in Core and Hybrid Heat pathways. By 2050, all fossil fuels are replaced with carbon-neutral variants, produced either from biological material or synthesized using electricity and concentrated carbon streams. Most of this transition occurs between 2045-2050.

Even accounting for the increased fuel demand, the reduced electric infrastructure requirements of the Hybrid Heat pathway translate to lower energy supply costs. The cumulative savings to Maine customers (including savings from reduced generation, transmission, and distribution requirements, netting out additional spending on clean fuels) translates to $2.73 per-MMBTU of space heating demand served from 2035-2050.[108]

However, while the Hybrid Heat approach reduces supply-side infrastructure requirements, it increases costs and complexity for customers on the demand-side. About 75% of the reduction in electric supply costs are offset by the additional cost of installing and maintaining boiler and heat pumps in homes.

Another concern with the Hybrid Heat approach is that its efficient operation is predicated on the availability and use of integrated controls that can effectively coordinate the operation of the heat pump with the boiler. Most Maine homeowners now adopting heat pumps have separate thermostats to control their heat pump and their legacy fuel-based heating system; this often results in the legacy system being used more than intended.[109] Related concerns, discussed further in the Key Policy Implications section below, involve how "clean" future fuels will be (i.e., their implicit GHG emissions, which may

[108] To provide a point of comparison, the average cost of heating oil in Maine is approximately $3.85 per-gallon, or $27.90 per-MMBTU. Source: U.S. Energy Information Administration. "Weekly Maine No. 2 Heating Oil Residential Price (Dollars per Gallon)," June 5, 2024.

[109] David Korn, Wayne Leonard, Patrick Sudol, Nicole Buccitelli, and Will Rambur. "Efficiency Maine Residential Heat Pump Impact Evaluation," March 7, 2024.

depend on how they are produced), and whether they will be available in the volumes needed to support a Hybrid Heating approach.

A potentially more sophisticated vision of hybrid heating, not analyzed here nor currently available, may be to size the heat pump to carry a home's full heating load while retaining the existing boiler in some homes to be used as "dispatchable resources," displacing heating demand from heat pumps and thus removing load from the electricity system when it is most stressed (e.g., in extreme cold or when there is a dearth of renewable generation). This "dispatchable dual fuel" strategy may allow Maine to capture many of the benefits of hybrid heating (namely, limiting the need to expand the electric transmission and distribution systems, and reducing the need for peaking thermal generators) without significantly increasing demand for carbon-neutral fuels in homes. This approach would require advanced controls capable of coordinating the operation of heat pumps and boilers in tandem while also responding to signals from the grid operator. This technology is not currently commercially available, though many of the components it would require do exist.

3. No Flexible Load and High Flexible Load Pathways

- Higher load flexibility helps manage electricity system peaks, limiting T&D upgrades, generation and storage needs, and costs.
- Absent load flexibility, electricity system peaks grow quickly, and more thermal generation and energy storage capacity is needed for the bulk power system to compensate for the lost load flexibility.

The Core pathway involves a "Medium" amount of load flexibility. For the most important source of flexibility, EV charging, two-thirds of load can be delayed by up to 8 hours in response to system conditions, in the long run. This flexibility helps to match demand to available supply on an hour-to-hour timescale, which reduces the amount of supply resources required while ensuring reliable system operation. The primary impact is on the amount of transmission and distribution (T&D) infrastructure, as well as generation and storage requirements needed to cover peak loads.

As an example, Figure III-21 illustrates how load flexibility can reduce peak load by shifting EV charging load to early morning hours, without changing overall electricity consumption. The light blue sections of the bars on the right show how charging load changes compared to the case without flexibility. In this example, by shifting much of the charging load away from hours 16 to 22 (4 pm to 10 pm), towards midnight to 6 am, peak load can be reduced considerably. Other end uses can also provide some load flexibility, though EV charging is the largest flexible load in terms of energy use, and also one of the most flexible.

The No Flexible Load and High Flexible Load pathways simulate alternative flexibility levels to explore the impact different levels of flexibility can have on infrastructure requirements. Figure III-22 describes the amounts of load flexibility modeled for these two alternative pathways, as well as other pathways—specifying for different load types the share of load that is flexible, and how far that flexible load can be shifted in time. (The High DER + High Flex pathway, discussed in the following section, also incorporates High load flexibility.) In simulating a given pathway, the model adjusts the timing of flexible load within these established limits, in response to hourly system conditions, to minimize costs.

The High Flexible Load pathway explores higher customer participation and technological advancements that could unlock even greater flexibility. The No Flexible Load pathway explores an extreme scenario with No flexible load, serving as a baseline to quantify the value of Medium and High flexibility levels.

The key outcome is that load flexibility primarily influences the realized peak electric load (e.g., see the distribution peak effect illustrated in Figure III-21). The presence or absence of load flexibility has little impact on overall energy production as it mostly affects the timing of energy use.

In the No Flexible Load pathway, the electric distribution system peaks grow quickly (about 10% higher than Core in 2050) and requires ~15% more thermal generation capacity and 50% more energy storage capacity for the bulk power system by 2050 in New England, relative to the Core pathway. The additional bulk battery storage provides flexibility on the supply side to compensate for the flexibility lost on the demand side. As a result of these increased resource needs, energy supply costs are higher than in the Core pathway for both Maine and for New England throughout the 2023–2050 timeframe. The largest part of the additional cost originates from increased distribution system costs, along with some additional cost for energy storage.

On the other hand, in the High Flexible Load pathway, the additional flexibility further mitigates peak, which is about 10% lower than Core in 2050 across New England. This limits distribution peak growth (thus T&D upgrade needs), generation and storage needs, and thus costs. Compared to Core, energy supply costs in this pathway are 1–5% lower, mainly due to lower T&D, wind, and energy storage costs.

In both the No Flexible Load and High Flexible Load pathways, the annual difference in supply costs relative to the Core pathway grows over time. The increasing year-over-year benefits of flexible demand can be attributed to the declining share of thermal resources within the generation fleet, which have traditionally been used to provide firm capacity.

While the model assumes varying degrees of load flexibility for the different pathways, there will be a need for investments and programs to unlock this flexibility. The costs associated with enabling technologies that may be needed to implement flexibility are not considered explicitly here. Maine has already deployed advanced metering infrastructure to a large extent,[110] enabling Maine customers to take advantage of time-varying electricity rates, such as time-of-use or peak time rebate rates for residential customers, or interruptible tariffs for larger customers that shift demand to off-peak periods. Time-varying electricity rates and managed EV charging programs, including vehicle-to-grid (V2G) technology, will be crucial to ensuring customer participation, to increase utilization of the electric infrastructure and minimize the need for costly expansions. Other opportunities, including behind-the-meter storage, virtual power plants, and demand response, also increase the load flexibility on the system. Specific policy considerations related to load flexibility are discussed in further detail in the Key Policy Implications section.

---

[110] U.S. Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861, "Advanced_Meters_2022.xlsx," October 5, 2023.

FIGURE III-21: EXAMPLE OF LOAD FLEXIBILITY: BATTERY ELECTRIC VEHICLE CHARGING

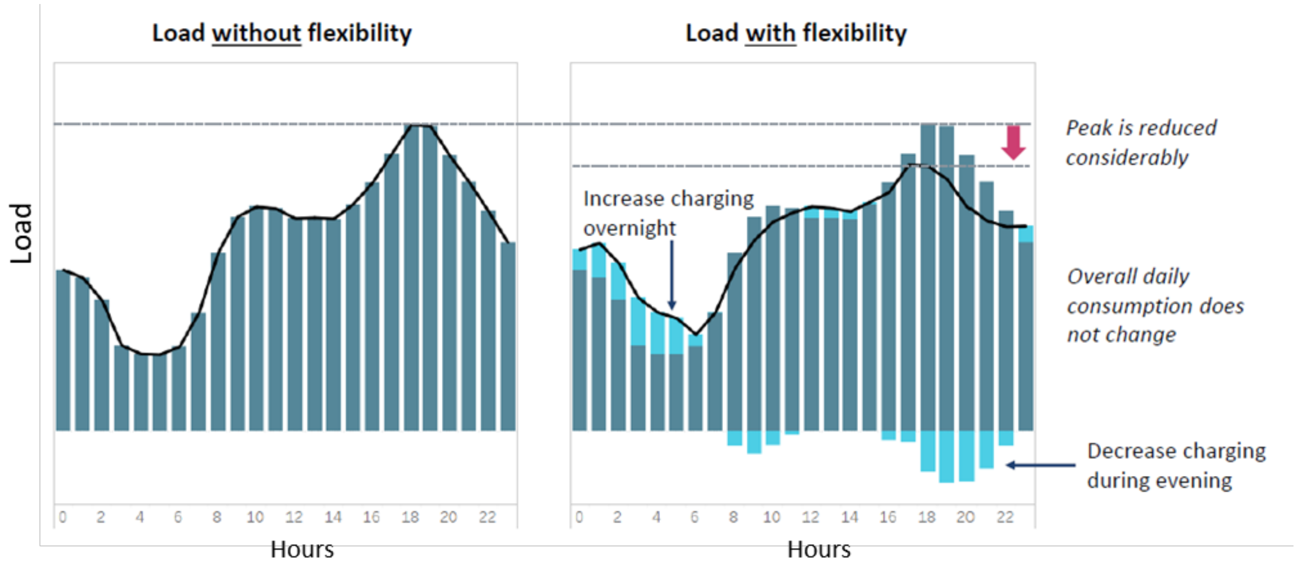


FIGURE III-22: LOAD FLEXIBILITY LEVELS

Load Flexibility Level (Corresponding Pathways)	Description
None **(No Flexible Load)**	All load occurs at nominal time. Zero load flexibility from electric vehicle charging, air conditioning, space heating, water heating.
Medium **(Core, 100% Renewable Generation, Hybrid Heat)**	67% of EV load can be delayed up to 8 hours. 10% of space heating/cooling load can shift one hour. 10% of water heating load can shift up to 2 hours.
High **(High Flexible Load, High DER + High Flex)**	100% of EV load can be delayed up to 24 hours, with LDVs including limited V2G capability. Heat pumps (for heating and cooling) include thermal storage enabling four hours of pre-conditioning. 50% of space heating/cooling load can shift one hour. 50% of water heating load can shift up to 2 hours.

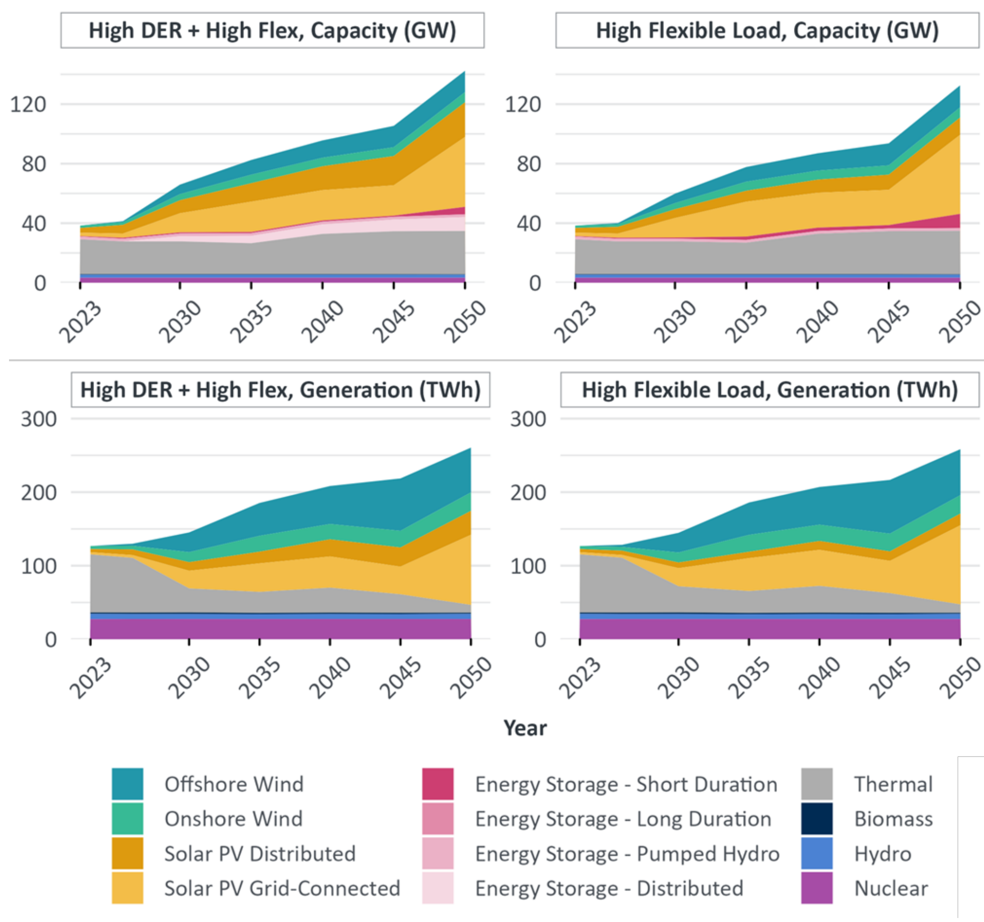
4. High Distributed Energy Resources (DER) + High Flex Pathway

- Higher adoption of DERs mitigates the electricity system peak, lowering distribution costs in Maine and New England.
- The additional cost of distributed resources makes this pathway more costly than the High Flexible Load pathway.
- Strategically deploying DERs where they are best positioned to defer infrastructure upgrades may improve their benefit-cost ratio.

The goal of this pathway is to test the impacts of a plausible increase in DER adoption. The pathway builds on the High Flexible Load pathway, assuming the same high level of load flexibility, while also doubling the amount of distributed solar PV and increasing the adoption of distributed energy storage.

Distributed solar deployment in New England is assumed to be twice that in the High Flexible Load pathways by 2050 (23.3 GW vs. 11.7 GW, see Figure III-23). Distributed storage capacity increases to 9 GW across New England in 2050, representing more than 50% of the total storage capacity of 16 GW (Figure III-15). In contrast, the High Flexible Load pathway only grows bulk storage, which benefits from economies of scale relative to distributed storage. Within Maine, distributed solar capacity is twice as high as the High Flexible Load pathway in 2050 (1.72 GW vs. 0.86 GW), with distributed storage

FIGURE III-23: ELECTRICITY SUPPLY IN NEW ENGLAND IN HIGH DER + HIGH FLEX (LEFT) AND THE HIGH FLEXIBLE LOAD (RIGHT) PATHWAYS



deployment equal to 40% of distributed solar (~0.7 GW), based on historical trends.[111]

For the New England grid as a whole, adding more distributed storage leads to a 42% increase in total battery storage *power* capacity (in GW terms) by 2050 relative to the High Flexible Load pathway (16.2 GW in the High DER + High Flex pathway versus 11.4 GW in the High Flexible Load pathway, including both distributed and bulk battery storage). However, since distributed storage has shorter duration, the *energy* capacity (in GWh terms) is only about 30% greater (66.8 GWh in the High DER + High Flex pathway versus 52.1 GWh in the High Flexible Load pathway).

The higher amounts of distributed solar also leads to a reduction in utility-scale solar in Maine and across New England. The additional 0.86 GW of distributed solar in the High DER + High Flex pathways displaces 0.47 GW of utility-scale in Maine in 2050. Across New England, the additional 11.7 GW of distributed solar displaces 6.1 GW of utility-scale solar compared to the High Flexible Load pathway. The increased adoption of distributed solar also modestly decreases wind power generation in Maine and New England, though only by a few percent. The High DER + High Flex pathway does not materially reduce the *capacity* of thermal generation relative the High Flexible Load pathway, but does reduce the *energy* produced by thermal generation in New England by about 7%.

The primary impact observed in this pathway is that the additional DERs further mitigate the growth needed in the distribution infrastructure, resulting in a lower distribution system peak than that seen in the High Flexible Load pathway (see Figure III-18 above), and therefore lower distribution costs in Maine and in New England. Still, the cost savings in the High DER + High Flex pathway, relative to Core, result primarily from the high load flexibility it incorporates. The additional cost of distributed resources, which are more costly than their utility-scale counterparts, makes this pathway somewhat *more costly* overall than the High Flexible Load pathway. Notably, the High DER + High Flex pathway also results in higher costs than the Core pathway in the early years, because the additional cost of DER capacity is incurred before the benefits of increased flexibility are realized.

Note that the DER adoption strategy assumed in this pathway is not targeted to specific locations on the distribution system. If DERs were strategically deployed with regard to location and timing,[112] it might lead to greater benefits in terms of avoided distribution costs. Incentivizing customers at these specific locations to adopt DERs would require that utilities include DERs in their distribution system planning, and that they provide customers with a robust system of non-wire alternative (NWA) incentives to promote participation.

Should interconnection delays stall the development of utility-scale renewable generation, smaller distribution-connected renewables that are quicker to deploy may play an important role in helping Maine achieve its renewable energy targets. Commercial/community scale DERs may provide similar advantages while benefiting from greater economies of scale than residential systems.

[111] The 40% relationship between the amount of storage and solar is an assumption, not a modeling result; the actual relationship will ultimately depend on various factors influencing the adoption of distributed energy storage such as electricity rates, technology costs, and solar quality.

[112] E.g., Solar+storage installed near a substation that was operating at its peak capacity, relieving the transformers of some load, and thereby deferring or avoiding sizable upgrade costs. The economy-wide modeling approach deployed in this study is not designed to capture the granularity that would be required to make this assessment.

IV. Key Policy Implications

The pathway analyses investigate alternative approaches for Maine to decarbonize its economy to explore and learn about the strengths and weaknesses of particular approaches, common factors across different approaches, and key sensitivities and challenges. The results provide valuable insights into the timing with which various issues are likely to arise and need to be addressed over the next several decades. The insights gained from these analyses can then be used to develop policies, guide future investigations, and support a robust path forward that will be achievable, affordable, and responsive to future developments. This chapter relates those themes to Maine's policy goals, discusses potential policy mechanisms that may help to achieve those goals, and identifies barriers and challenges to implementation.

The primary policy implication is that all of the modeled pathways achieve Maine's broadest clean energy goals—80% renewable electricity by 2030, 100% clean electricity by 2040, and carbon neutrality by 2045—and do so while keeping total energy supply costs generally in line with current costs. Thus, the pathway analyses provide support for setting and achieving these high-level energy and climate-related policies, while offering indications about which pathways are likely to present opportunities and challenges. The different pathways that may be pursued to achieve those overall goals do have varying implications in terms of the infrastructure changes needed and overall energy system costs, and these differences have important implications for policy decisions that must weigh the associated benefits, risks, and costs. But none of these pathways involve insurmountable barriers or prohibitive costs. Although they may involve varying degrees of implementation challenges and risks, all of them appear to be achievable, at least in principle, with sufficient will and resources.

The next several subsections discuss particular topics and observations from the analytic modeling of pathways, organized broadly by supply-side and demand-side issues, plus several overarching topics. These observations offer guidance regarding how policy support may help to achieve an affordable and effective energy transition in Maine.

A. Supply-Side Policy Topics

1. Maine Must Follow Through on its Procurement Commitments for Clean Energy to Meet its 2040 Goals

Maine will need to accelerate its procurement of renewable and clean energy to reach 100% clean electricity by 2040. Currently, Maine is procuring about 6,000 GWh per year of renewable generation, 51% of its annual demand, primarily from in-state small hydro and biomass facilities.[113] To cost effectively achieve 100% clean electricity by 2040, Maine will need to increase its total clean generation to about 24,000 GWh per year. Even beyond 2040, Maine's clean power requirements will continue to grow, due to continuing demand growth from electrification.

Maine is already taking significant steps to add clean electricity resources through its commitment to offshore wind, Northern Maine Renewable Energy Development Program, and additional solar as described in the Introduction and Background section of this study, and discussed in detail in a recent report,

[113] Estimated based on RPS requirements for Class I, IA, II resources per 35-A M.R.S. §3210. Renewable Resources

An Assessment of Maine's Renewable Portfolio Standard.[114] Maine will need to follow through on these plans; as it does so, it will be important for Maine to coordinate with other states and entities in the region (see Section IV.C.4 below for further discussion of this). The near-term gap between the clean electricity demand and the planned/contracted resources will need to be met by additional contracts or increased REC purchases.

As a next step, Maine will also need to define which energy resources qualify as *clean* besides renewables, in pursuing its target of 100% clean electricity by 2040. The definition of clean resources has not yet been precisely specified in Maine, but must be clarified in the near term to ensure it can plan, develop, and utilize these resources in an orderly way to meet the 2040 target.[115]

The majority of the incremental renewable energy is likely to be Gulf of Maine offshore wind, as Maine set a target of at least 3 GW of floating offshore wind turbines by 2040 and has taken significant steps in pursuing offshore wind. Due to the significant role offshore wind is projected to play in achieving its goal, Maine must identify the most cost-effective approach to procuring those resources and prepare for the challenges that may arise in developing it. Offshore wind remains a new generation technology in New England, and it has faced considerable challenges with procurement, permitting, and construction over the past 5–10 years related to cost escalation, federal permitting, and transmission development. In addition, Gulf of Maine offshore wind will require new floating offshore wind turbine technology. While this technology is currently receiving considerable support through several state and national initiatives (including the Maine Offshore Wind Research Array, the U.S. DOE Offshore Wind Shot, and California's pursuit of 25 GW of offshore wind), and the 88 MW Hywind Tampen wind farm in Norway recently became the first commercial floating offshore wind plant,[116] it remains a nascent technology.

Given the state of floating offshore wind technology and its importance for achieving 100% clean electricity, Maine will need to sharpen its understanding of the development timeframe for floating offshore wind farms, including federal permitting, construction supply chains, and transmission development, to ensure it can achieve the target online dates (likely 2035–2040) for 3 GW of Maine offshore wind. Other important next steps for the state in pursuing offshore wind include: (1) ramping up staffing within Maine state government to support the development of offshore wind; (2) identifying feasible onshore points of interconnection; and (3) collaborating with other New England states on developing a strategy for offshore wind transmission.[117]

Maine can learn from approaches taken by other New England states to de-risk the long lead time for developing offshore wind. Cancellations of recent offshore wind contracts in other New England states have been driven by the combination of historically

[114] "An Assessment of Maine's Renewable Portfolio Standard" prepared by Sustainable Energy Advantage, LLC, for the Maine Governor's Energy Office, in collaboration with the Public Utilities Commission, March 31, 2024. This report evaluates the impact of RPS on Maine's economy and also discusses several considerations to improve for future large-scale procurements, e.g. to reduce attrition, reduce risk exposure to changing circumstances between bid development and contract approval, and to increase competition in bidding.

[115] The modeled clean electricity resources in this study include renewables as well as other alternative clean technologies, such as gas plants utilizing clean fuels or with carbon capture and sequestration, new nuclear, and new large hydropower.

[116] Equinor. Hywind Tampen: the world's first renewable power for offshore oil and gas.

[117] Pfeifenberger et al., The Benefit and Urgency of Planned Offshore Transmission, January 24, 2023.

high inflation rates, a lack of regional development capacity, and supply chain delays. Maine should consider contract structures that include pricing indexed to inflation or other public cost indices.

Beyond the resources already planned and committed, still more clean energy will be required to achieve 100% by 2040. Maine should continue to pursue opportunities to increase clean generation in northern Maine and for exports to the rest of New England, similar to the recent agreement with Massachusetts for the King Pine Wind Farm. Nearer-term shortfalls to meet rising renewable demand could be met either through additional short-term market purchases or clean electricity procurements, with the potential to sell RECs into the market once offshore wind is operational.

Maine's nearer-term RPS requirement of 80% renewable energy by 2030 is achievable, but will require an additional ~5,700 GWh of renewable energy generation beyond current levels. Resources developed in northern Maine, such as the King Pine Wind Farm or an equivalent project would fulfill this requirement, if it can be completed in time. If this project is significantly delayed, an alternative approach will be needed to meet the 2030 goal.

2. Thermal Electricity Generation with Clean Fuel Facilitates High Renewable Penetration

The challenges demonstrated by the 100% Renewable Generation pathway, including relying on a large amount of LDES, suggest that Maine's 100% clean electricity by 2040 goal should accommodate clean, dispatchable thermal generation. This will allow the system to best meet power system reliability needs and manage costs. While the 100% Renewable Generation pathway shows that meeting the state's goals without any thermal generation is probably possible, it would be more challenging and more costly, requiring a much larger buildout of LDES to provide dispatchable capacity, and significant amounts of additional renewable generation to charge this storage.[118]

A pathway that includes a significant amount of thermal generating capacity will be more practical and lower cost. This thermal generation would need to operate only infrequently, utilizing carbon-neutral fuels, when other resources are unavailable—typically during extended periods of low renewable output when loads are reasonably high, often in winter. With about a 2% capacity factor on average, its overall fuel demand would be quite low. Much of this clean thermal generation could be provided by existing gas-fired generators adapted as necessary to operate on clean fuels, such as renewable natural gas (RNG), synthetic natural gas (SNG), hydrogen, or biodiesel.[119] Some additional new thermal generation capacity (about 6.5 GW across New England in 2050) will likely be needed to meet the higher net peak loads that will accompany widespread electrification. Still, in the longer run, renewable energy will likely provide more than 80% of total energy requirements across New England (New England reaches 84–99%

[118] In the 100% Renewable Generation pathway, combustion-driven thermal generators (i.e.., those combusting fuels such as natural gas, fuel oil, or their clean counterparts) are eliminated by 2040 in Maine and by 2050 in New England. Nuclear power plants are eliminated by 2050 in New England in this pathway.

[119] It will be important to understand the extent to which these "clean" fuels are actually low/zero-carbon, according to a lifecycle analysis that accounts for emissions during production, transportation, and use. If there are any small residual non-zero GHG emissions associated with "clean" fuels, it will be important to mitigate or offset those emissions, to be able to meet the 100% clean electricity requirement.

renewable energy in 2050 across pathways), even if a share higher than 80% is not explicitly required.[120]

Increasing the renewable electricity requirement to 100% by 2040 (even if existing nuclear and hydro are allowed to qualify) in such a way that excludes clean thermal generation would be a more challenging and costly approach. Maintaining the current renewable requirement, while broadening the qualification requirements to explicitly include clean thermal generation for meeting the balance to 100% clean, will make it easier and less costly to achieve the state's goals. On the other hand, battery or LDES costs might decline more quickly than anticipated, and these technologies could conceivably overtake dispatchable clean thermal generation in the marketplace. This suggests that as a policy matter, it would be best to allow either clean thermal generation or batteries/LDES (with renewable generation for charging) to meet the final 20% of the 2040 clean energy requirement beyond the 80% RPS, but not to require any specific technology to do so.

3. Policymakers Must Continue to Modernize Transmission and Distribution Planning to Facilitate Clean Energy Goals

Maine's clean energy transition will significantly increase the scale of the electric power system across all pathways modeled, including the electrical infrastructure that transmits and distributes electricity from generation resources to the ultimate customer. The primary drivers of the need to expand transmission and distribution are the increase in peak electricity demand and the location and type of generation resources. Delays in building out the future transmission and distribution systems could result in insufficient capacity to serve demand for clean power, limiting access to low-cost generation resources, delaying clean energy development, slowing customer adoption of electrified heating and transportation, and potentially even causing reliability problems.

Policymakers and grid planners will need to work together to develop proactive planning processes that consider these important changes so that the necessary upgrades and expansion to the grid are identified and developed by the time they are needed. It is necessary to start that process now, to ensure the system is built out cost effectively to accommodate the transition, and system reliability is maintained throughout the process. This section reviews key issues identified by our analyses that affect distribution and transmission system planning.

IDENTIFYING AND BUILDING COST EFFECTIVE TRANSMISSION UPGRADES

The pathways analysis demonstrates that significant transmission investments will be necessary for Maine to cost effectively achieve its clean energy goals and economy-wide greenhouse gas reduction requirements (and similar for other New England states). The primary transmission needs include:

- Upgrading local transmission to meet the rising peak load due to electrification;
- Building new transmission facilities to connect new onshore wind and offshore wind to the existing system and integrate it; and,

[120] The model does not assign which specific energy sources provide energy to Maine load, and similar for other states, because there is no unique answer. However, the model does ensure that the total amounts of renewable and clean generation across the region are sufficient to meet all states' needs simultaneously. Different combinations of resources—solar, onshore and offshore wind, existing nuclear, and hydro—could provide Maine's energy needs, with the corresponding balance providing other states' needs.

- Upgrading the regional transmission system between Maine and New Hampshire to better integrate Maine's generation and demand with the rest of New England and Canada.

ISO-NE recently identified in its 2050 Transmission Study similar regional transmission needs to meet clean energy and greenhouse gas reduction goals set by each of the New England states, which validates the findings of this pathways study.[121] Nearly half of the costs for regional upgrades identified in the 2050 Transmission Study are along a highly congested corridor from southern Maine into the Boston area, further demonstrating the need for Maine to pursue cost effective transmission upgrades to meet its clean energy goals.[122]

Based on these findings, the following are the key transmission-related takeaways for Maine policymakers:

- **Proactive Transmission Planning Reduces Ratepayer Costs**: Proactive transmission planning by ISO-NE and the Maine electric utilities will significantly reduce the costs of achieving future policy goals, relative to the status quo approach that focuses primarily on near-term reliability needs. The benefits of proactive planning are well documented across multiple jurisdictions, especially in power systems undergoing significant changes in demand and generation.[123] The need for proactive planning in Maine and New England is evident due to the significant and ongoing need for transmission investment through 2050. A near-term approach focused primarily on reliability will tend to result in piecemeal upgrades that may foreclose opportunities to building larger, more cost-effective regional solutions, and underutilize existing rights of way. Maine should leverage the findings of this study and the ISO-NE 2050 Transmission Study to identify opportunities throughout the transmission planning process, including local planning by Maine's electric utilities and regional planning by ISO-NE, to develop proactive least-regrets transmission upgrades that reduce ratepayer costs and create sufficient headroom on the system to achieve its clean energy goals.
- **Incorporate Electrification Load Growth Projections into Local Transmission Planning:** Maine and its electric utilities must plan the local transmission system for higher projected load growth due to electrification. The 2030 ISO-NE near-term regional planning study projects lower peak load (2,374 MW summer peak and 2,950 MW winter peak in 2032) than all of the pathways modeled in this report (2,900 MW summer peak and 3,500–3,900 MW winter peak in 2032), as shown in Figure III-4 above.[124] Maine should ensure that its near-term electrification load growth projections account for updated heat pump adoption goals and anticipated EV charging loads, and are accurately represented in regional load projections and transmission planning by

[121] The study is the first longer-term transmission study (LTTS) completed by ISO-NE at the request of the New England States Committee on Electricity (NESCOE). The ISO-NE study uses more detailed technical models of the power system to identify necessary transmission needs and solutions than utilized in the 2040 pathways model. ISO New England Inc., 2050 Transmission Study, Transmission Planning, February 12, 2024. ("2050 Transmission Study")

[122] 2050 Transmission Study, p. 55.

[123] Pfeifenberger, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Prepared for American Council on Renewable Energy and the Natural Resource Defense Council, October 2021.

[124] ISO New England Inc., ISO-NE 2023 Forecast Data File, Summer and Winter Peak Load Forecasts, April 28, 2023.

ISO-NE and local transmission planning by the Maine utilities.

- **Identify Opportunities to Upgrade Aging Infrastructure:** Maine's infrastructure was built primarily during a period of high load growth in the mid-to-late 20th century.[125] Many of the existing high-voltage lines in Maine will need to be replaced in the next 10–20 years. The 2050 Transmission Study identified rebuilding aging transmission lines as a cost-effective approach to increasing system capacity while limiting impacts on land use.[126] Maximizing the use of existing rights of way will be crucial to achieving clean energy goals. Maine should work with its electric utilities to identify aging infrastructure in the regional corridors identified in recent ISO-NE studies (including the 2050 Transmission Study and earlier Maine Resource Integration Studies) and near potential points of interconnection for offshore wind. Doing so now will ensure that when aging lines need to be addressed, ISO-NE and the Maine electric utilities consider the opportunity to cost effectively upsize those facilities to create headroom for serving higher future demand and generation.
- **Leverage ISO-NE LTTS Process to Identify Cost-Effective Transmission Upgrades:** The ISO-NE Longer-Term Transmission Study (LTTS) process provides Maine and the other New England states the opportunity to request that ISO-NE seek cost-effective solutions through a competitive solicitation to specific long-term needs identified.[127] Maine should collaborate with the other New England states to identify long-term needs from the 2050 Transmission Study and other regional studies. The primary needs that Maine should request include: (1) regional upgrades between Maine and Boston (referred to as the "North-South/Boston Import upgrades"); (2) upgrades to access 1.2–2.4 GW of onshore wind from northern Maine; and (3) upgrades to interconnect up to 3 GW of offshore wind in the Gulf of Maine. Considering all three collectively will result in lower cost solutions compared to evaluating each need separately, as the needs overlap, as illustrated in Figure IV-1 below.[128] Evaluating these needs in a regional process is likely to identify benefits to a wider range of states and ratepayers than would be considered if the same projects were pursued primarily for delivery of renewable generation to Maine.[129] In addition to its own needs, Maine should encourage the inclusion of other regional transmission needs in a single LTTS request.

[125] Transmission asset life can range widely with most facilities estimated to have a 50–80-year life. Electricity load growth in Maine averaged 4.9% per year from 1960 to 1990 and then demand remained flat from 1990 to 2022. U.S. Energy Information Administration, EIA-861 Annual Electric Power Industry Report, October 5, 2023.

[126] "Since a significant portion of New England's transmission system was developed in the mid-20th century, many transmission lines are beginning to reach the end of their life and must be replaced. During such an asset condition replacement project, the incremental cost of upgrading a transmission line to a larger conductor size and stronger structures is relatively low." ISO New England, Inc. 2050 Transmission Study, February 12, 2024, p. 18.

[127] The LTTS Phase 2 process is being finalized as of the date of this report.

[128] The Suriowec substation is identified as a potential offshore wind interconnection point, and is also in a portion of the system requiring upgrades for north-south flow. Similarly, the Orrington substation is a potential offshore wind interconnection point and is located on the corridor for delivering onshore wind.

[129] For example, the ARG project was intended to access onshore wind for delivery to Maine and Massachusetts utilities, with cost allocation between the two states. Similar upgrades may result in benefits to ratepayers in other states if studied in the LTTS, supporting broader cost allocation.

Studying a region-wide portfolio of needs will have two benefits: first, similar to Maine's needs, a larger set of needs is likely to identify more cost effective upgrades than considering each separately; and second, a region-wide portfolio will produce more evenly distributed benefits that support using a simpler and less contentious portfolio-based cost recovery approach, while still ensuring costs allocated to each state are roughly commensurate with benefits.[130]

- **Ensure ISO-NE Considers All Cost-Effective Transmission Solutions***:* Maine should encourage ISO-NE and in-state transmission owners to incorporate lower-cost and higher-capacity alternatives into their planning processes. ISO-NE can build on the experience of other RTOs that have incorporated grid enhancing technologies (GETs) into their planning and operational processes to provide lower-cost and shorter-timeframe solutions, compared with building new transmission infrastructure.[131] In addition, ISO-NE should continue to pursue an increase in the single loss of source limit from 1,200 MW to 2,000 MW, to allow higher-capacity transmission facilities, such as bipole high-voltage direct current (HVDC) or double-circuited 345 kV lines, to be built within its system.

RE-THINKING DISTRIBUTION SYSTEM PLANNING FOR THE CLEAN ENERGY FUTURE

Maine's distribution system will play an increasingly important and evolving role in providing energy services throughout the economy, reducing greenhouse gas emissions, and doing so at least cost to ratepayers. While electricity today represents 15% of overall economy-wide energy delivery, this will increase to roughly 75% by 2050 (see Figure III-1 above), putting additional focus on providing reliable service via the electric distribution system. At the same time as electricity demand is rising, electric system planners and operators will need to adapt to new end-use demands, increasing distributed energy resources (e.g., behind-the-meter solar and storage), more responsive demand via load flexibility, and modernized retail rates.[132]

Starting in 2022, the Maine Public Utilities Commission (MPUC) initiated a docket focusing on the need for improved distribution planning to account for these important changes.[133] That docket will result in the MPUC specifying the expected

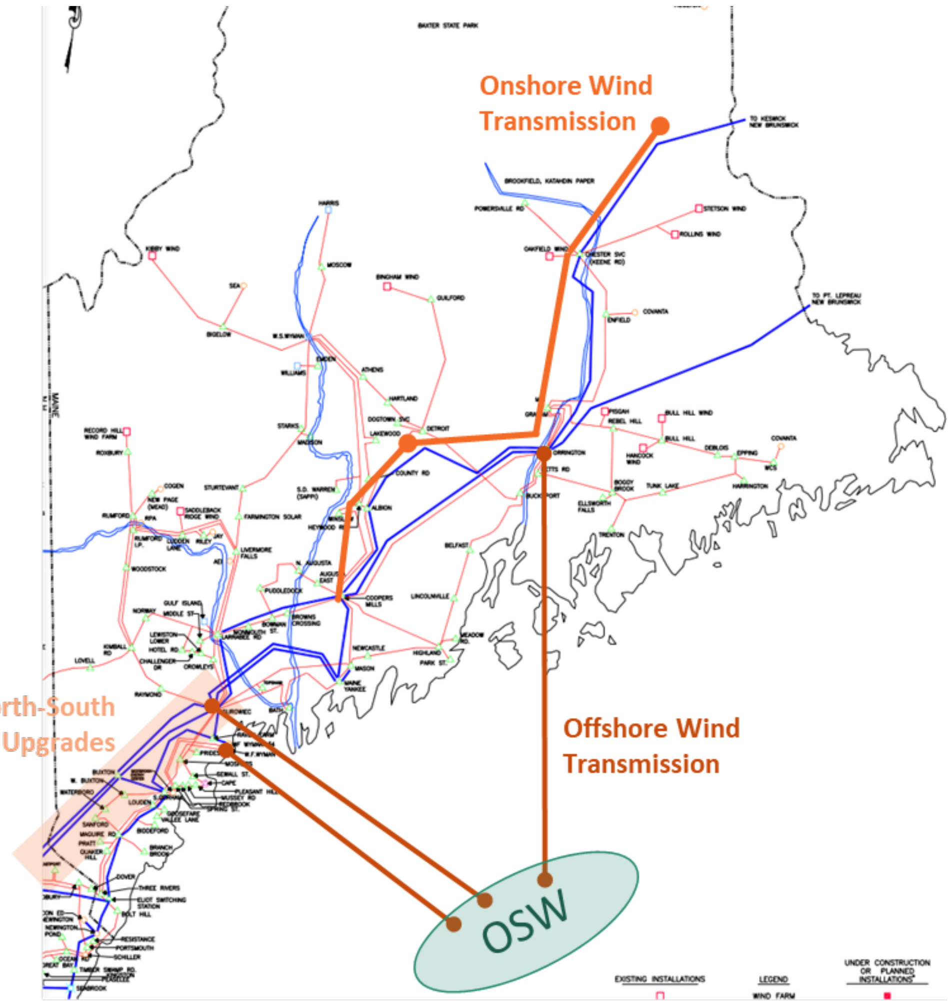
[130] MISO's Long-Range Transmission Planning (LRTP) process and CAISO's annual Transmission Planning Process both successfully rely on a region-wide approach to identifying cost-effective transmission upgrades and allocating the resulting costs across their markets. Pfeifenberger, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Prepared for American Council on Renewable Energy and the Natural Resource Defense Council, October 2021, p. 65.

[131] Dynamic line ratings (DLRs) have been deployed in PJM and NYISO, and topology control has been deployed in SPP and MISO to reduce congestion and avoid higher cost upgrades. Tsuchida, et al. Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts. April 20, 2023.
CAISO estimates it can incorporate 21 GW of renewable energy resources on its system without further transmission upgrades by relying on Remedial Action Schemes (RAS) to resolve reliability issues. RAS are short-term curtailments of renewable energy output that may occur under certain system conditions and can avoid the need to build new facilities. California ISO, Briefing on Resources available for near term interconnection. December 5, 2023.

[132] Maine's distribution system is currently planned, constructed, and maintained by its electric distribution utilities. These include Versant Power, Central Maine Power, and several smaller municipal utilities/electric coops.

[133] Maine Public Utilities Commission, Docket 2022-00322. MPUC's Order (Item 108) requires that CMP and Versant file their grid plans by January 12, 2026.

FIGURE IV-1: PRIMARY MAINE TRANSMISSION NEEDS



Source: Base map is sourced from [ISO-NE](ISO-NE).

content of utilities' future grid plans. One of the key elements of the docket has been forecasting future electrification demand. To support Maine's clean energy and climate goals, the electric utilities will need to account for the unique impacts of electrification on the distribution system to properly plan future upgrades. While electrification of heating and transportation will clearly increase overall demand, the pace and location of electrification, and the role that load flexibility can play in mitigating its impacts, are less straightforward.

A key challenge for projecting electrification demand is identifying the portions of the system in which adoption will occur in the near term and long term. Electric utilities must track early adoption in their systems, as well as national trends on the drivers of electrification adoption, to allow them to forecast where and when adoption will occur, and how EV charging and heat pump loads will be distributed both geographically and temporally. Doing so will allow them to target which portions of the system require upgrades and when, and to plan for the long term (e.g., to avoid multiple rounds of small upgrades, which are likely more costly than a single larger upgrade to achieve the needed final capacity). In addition, the temporal patterns of EV charging and electric heating will need to be studied for each local system to identify peak impacts, which will differ for residential and commercial customers.

Most analysis of the system impacts of electrification to date (including the analysis in this study) is at the system-wide level, finding significant but manageable demand growth. However, distribution system capacity needs will likely grow by more than system-wide peak demand, which is diversified across many customers and locations. These averaging effects do not occur to the same extent at the local distribution system level. Instead, each portion of the distribution system will need to accommodate its own local peak demand (more similar to noncoincident peak at the system level), with different types of feeders experiencing varying rates of adoption and different patterns of demand throughout the year and within the day. For example, most EV charging (perhaps 80–95%) will likely occur at residential locations in the evening and overnight hours, while the remaining charging will occur at commercial locations (workplaces and public chargers) in the late morning to mid-day. Some areas of Maine will experience seasonal peaks in EV charging demand, such as weekend and holiday periods for highway charging stations and summer vacation rental homes located near popular vacation destinations. The distribution system will need to be built out to serve the peak demand that occurs at each local part of the system.

Temporal aspects of heating demand tend to be more predictable, with peak demand occurring on the same days (depending on the weather) and at the same times (most concentrated in the morning) across geographies, with residential heating demand peaking earlier in the day than commercial demand. Proper planning for heating electrification will require consideration of historical and future weather conditions, and the heating demands that will occur during the coldest periods, while accounting for building efficiency improvements.

Distribution planning will also need to account for a large increase in DERs, including behind-the-meter solar and storage, and load flexibility. But there may be opportunities for the grid operator to influence distribution peaks—managed charging and smart thermostat/water heating programs can mitigate some of the impacts on local peaks. EVs are particularly important, since they represent a very large load that is potentially quite flexible. Not all vehicles will need to charge every day and, if they are coordinated properly, they can adjust their charging times to accommodate other grid needs. To do this, the programs must be designed to account for the local distribution system as well as the system-wide impacts on generation and transmission capacity. Maine recently deployed Advanced Metering Infrastructure (AMI), which can support load flexibility when coupled with time-varying rates, such as time-of-use or peak time rebate rates for residential customers or interruptible tariffs for larger customers that shift demand to off-peak periods. Hybrid heating systems also have the potential to reduce peak heating demands, and thus the costs of building out the distribution system.

4. Ensure that Fuels Become Cleaner with Time

Maine may not have direct control over the total amount of fuels used in the state, as discussed above. Even if hybrid heating systems are installed, consumers may rely more on fuel and less on electricity than anticipated in the pathway modeling. This is true in other fuel-reliant sectors such as transportation as well.

However, it may still be possible to reconcile this with the need to decarbonize the economy rapidly. One approach is to ensure that fuels themselves become cleaner over time, so that even if fuel use declines less quickly than anticipated, GHG emissions would nonetheless continue their downward trajectory toward the state’s goals. For example, a requirement to blend an increasing share of clean fuels into fossil fuels will cause emissions to fall, even if fuel use continues. Rhode Island, for instance, has mandated increasing biodiesel blending with heating oil, rising to 50% by 2030.[134] Connecticut and Massachusetts have blending requirements for low-emitting fuels. California has effectively displaced about half of its diesel consumption with lower emitting renewable diesel through its Low-Carbon Fuel Standard (LCFS).[135]

If linked to the amount of overall fuel use, a blending requirement could establish a declining cap on overall fossil use, even if total fuel use was not capped. Higher fuel use would imply a higher clean blending requirement. Such an approach could ensure that emissions targets are met, whether end uses are electrified quickly or continue to rely on fuels to a greater extent than anticipated.

In the longer term, if fuel use remains high, a blending requirement may begin to run up against limits on the availability and/or cost of clean fuels for blending. Available evidence suggests that many clean fuels will have limited supply, and their cost will likely be materially higher than historic fossil fuels prices. While this may create short-term challenges and costs that need to be managed, it will provide appropriate long-term incentives. Continued reliance on fuels that have increasing blending requirements and thus increasing costs will create increasing incentives to electrify those end uses. Since fuel distribution networks are interstate, blending requirements may be easier and less costly to implement if Maine coordinates its blending requirements with neighboring states, so that a multi-state region can be served by a uniform and integrated distribution network.

It will be important to ensure that the blended fuels are actually carbon-neutral, accounting for lifecycle emissions based on the processes used to produce and transport the fuel involved, not simply an assumption based on the fuel type.

B. Demand-Side Policy Topics

1. Electrifying Transportation is Key to Cost Effective GHG Reductions and Electricity Grid Investment

The electrification of transportation is a key ingredient in achieving Maine's renewable, clean energy and GHG goals. One clear reason, as recognized in *Maine Won't Wait* and the most recent Maine Climate Council Annual Report (December 2023), is that the transportation sector accounts for the largest share of Maine's GHG emissions—49% of the total as of 2019.[136] It will also account for significant fuel cost savings as EVs substitute for ICE vehicles—this can offset cost increases in other energy sectors (for instance, overall electricity costs will rise since more energy demand will be served by electricity). Perhaps less obvious is that highly electrified transportation will play a significant role in integrating renewable energy. As discussed below, EV charging can provide a large and effective source of flexible load to facilitate effective and economic grid management in a highly decarbonized system.

Facilitating EV adoption must start with facilitating EV purchases, such as with rebates that incentivize customers to purchase EVs. Adoption can also be encouraged further by improving the public's general

[134] The 5% requirement set in 2013 was increased by 2021 legislation to 10% in 2023 and 50% in 2030.

[135] California Air Resources Board. LCFS Data Dashboard. Updated 9/10/2023.

[136] Based on CO_2 emissions from fossil fuel combustion. Sourced from Maine DEP, "Ninth Biennial Report on Progress toward Greenhouse Gas Reduction Goals," 2022.

familiarity and experience with EVs. Widespread and easy access to high-speed public and private charging stations will help to reduce logistical barriers to EV ownership and will also increase public awareness of EVs in general and charging options in particular. This will be an important issue especially in rural portions of Maine where infrastructure may be thinly distributed. In addition to supporting EV adoption, availability of high-speed charging will enable load flexibility.

Another reason that transportation electrification is so important to GHG reduction goals is that, as shown by the modeling results above, it can be a primary driver of cost reductions. This is because fuel for conventional ICE vehicles is expensive and ICE vehicles use it very inefficiently (most ICE vehicles have efficiency of 12–30%).[137] A mid-size 24 mpg[138] SUV fueled with $3.30 per-gallon gasoline[139] costs $1,375 to drive 10,000 miles. By comparison, most electric SUVs have a fuel economy of 2–3 miles per-kWh.[140] At 25¢-per-kWh,[141] it would cost just $833–$1,250 to drive one of these SUVs the same distance. In the future, as electric rates and utility programs evolve to incentivize customers to charge their cars during off-peak hours using surplus renewable energy, price-conscious customers may be able to pay significantly less than this.

EVs also cost about half as much to maintain as ICE vehicles, largely because they have fewer moving parts.[142] Taken together, savings on vehicle fuel and maintenance can help to offset increases in electricity costs across the entire energy wallet.

2. Maximize Benefits from Heat Pumps While Managing System Peaks Through Flexibility

Heat pumps can reduce emissions by providing space and water heating with renewable electricity rather than fossil fuels. Maine is already taking a lead on heating electrification through its role in demonstrating cold climate air source heat pumps (ccASHPs), surpassing its 2025 goal of 100,000 heat pumps installed ahead of schedule, and increasing the goal to 275,000 heat pumps by 2027. Maine's experience may enable other states to make faster progress by learning and leveraging from its experience.[143] For Maine, taking the lead on heat pump adoption makes sense, since the state is more heavily dependent on oil for heating than other states, and heat pump economics compare more favorably with expensive heating oil than for lower-cost natural gas.

Most customers who adopt heat pumps in Maine retain their legacy heating systems for backup use. As highlighted in the Hybrid Heat pathway, there may be

[137] U.S. Department of Energy, Where the Energy Goes: Gasoline Vehicles, n.d.

[138] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. "Fuel Economy." Accessed March 19, 2024.

[139] AAA. "Gas Prices." Accessed March 19, 2024.

[140] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. "Fuel Economy of Electric Vehicles." Accessed March 19, 2024.

[141] This accounts for a combination of home charging and public fast-charging, which is substantially more expensive.

[142] Harto, Chris. "Electric Vehicle Ownership Costs: Today's Electric Vehicles Offer Big Savings for Consumers," *Consumer Reports*. October 2020.

[143] Since Maine is relatively small in global terms, Maine's ultimate impact on global GHG reduction might come more through its role in modeling effective heat pump adoption, which could accelerate adoption in much larger markets, rather than by the direct impact of transforming of its own heating sector.

potential benefits to this approach in the long run, particularly after 2035 as widespread heat pump adoption contributes to a growing winter electric peak. However, in practice many customers who retain their legacy fuel heating systems end up relying on them as their primary heat source and under-utilizing their heat pumps, resulting in higher total energy bills and greater emissions. According to a recent survey, about 20% of residential heat pump adoptees reported that they were not using their heat pump as their primary heating source.[144]

There are a number of potential tools that would help ensure that backup fuel heating systems are operated minimally, in a way that maximizes emissions reductions and cost savings. These include:

- **Integrated Controls.** While dual fuel thermostats that control a furnace and heat pump are readily available for homes with centrally-ducted heating and cooling, there are no commercial technologies currently available for mini-split systems installed in homes with fuel boilers (the standard in Maine). Consequently, customers are forced to manage set points on two separate thermostats and have limited control over their independent operation. Development of integrated controllers that can operate both heat pumps and boilers in tandem would greatly simplify heating operation in Maine homes with multiple systems.

- **Opt-In Thermostat Control Programs.** More advanced controls may be even more effective at mitigating electric peak—e.g., by responding to time-of-use electricity pricing or actual grid conditions. An advanced thermostat control program could allow a utility or aggregator to actively manage dual-fuel heating systems, choosing between the electric and fuel heating systems based on grid conditions to minimize costs and emissions while preserving thermal comfort. Thermostat programs for air conditioning are already in common use for managing summer peaks.[145] These could provide a model for managing heat pump demand as well.

- **Customer Education.** Customers who are accustomed to using a boiler or furnace may be unfamiliar with how heat pumps work and may not know how to or prefer not to set heat pump controls properly—due to behavioral inertia, lack of familiarity, or simply overriding the controls, intentionally or not. Engaging customers through educational campaigns may help to address this. Such campaigns may be run as public initiatives or as part of customer interaction through utility programs.

- **Improved Rate Design.** Because most residential customers in Maine are on electric rate plans that allocate fixed costs to volumetric consumption, the per-kilowatt-hour price includes a surcharge for transmission, distribution, and administrative expenses. This rate design increases the price of electricity relative to delivered fuels, which may deter some customers from utilizing their electric heat pumps, even if doing so would be economically efficient from a societal perspective. A number of rate reform options can be used to reduce the variable price of electricity, making the heat pump more attractive relative to burning fuel. These include time-of-use rates, increased fixed charges paired with decreased volumetric rates, and residential demand charges.

Enabling backup fuel heating in the short run need not prevent retiring legacy systems in the long run.

[144] Efficiency Maine. "Making the Switch: The Imperative to Convert the Whole Home (or Whole Building) to Heat Pumps."

[145] Northeast Energy Efficiency Partnerships. "Smart Energy Homes and Buildings Residential and Commercial Program Trackers." Accessed April 30, 2024.

Some customers who retain a legacy heating system may find that they do not ultimately need them. Others may wait until their legacy system fails and then choose to not replace it or remove it, e.g., when eventually replacing the initial heat pump with a higher-efficiency unit.

Another option for mitigating winter peaks is by utilizing ground-source heat pumps (GSHPs). The pathway modeling performed here did not explicitly consider GSHPs, or geothermal networks, which use a similar technology on a larger scale to serve many customers in a small geographic area. Both of these technologies utilize the ground as a source and sink for heat, but are otherwise similar to air-source heat pumps that utilize ambient air. Ground-source systems have higher initial cost due to the added cost of installing piping in the ground for heat exchange, but have higher efficiency, especially at extreme outside temperatures, because ground temperature changes little throughout the year. This greater efficiency is particularly valuable in extreme cold conditions, where air-source heat pumps become less efficient and require more power, creating high winter peak electric demands. GSHPs can help to mitigate the demand peaks that air-source heat pumps cause in cold weather, and thus can reduce the need for additional electric infrastructure and costs.

The fact that GSHPs were not explicitly modeled here does not imply that these may not be a useful technology, at least in some instances. This may be particularly true if advances in drilling technology reduce the initial cost premium, improving the economics relative to air-source heat pumps. Maine's low building density may make networked geothermal impractical in most of the state, although it does suggest that standalone GSHPs may be able to avoid some problems encountered in more densely populated regions, where small lots and densely packed buildings can make it challenging to install a ground loop.

Lastly, the Core Pathway assumes that the customers who fully electrify their space heating with heat pumps choose to size their heat pumps to cover all space heating demand above -20°F, relying on electric resistance only if the ambient temperature drops below this threshold. In practice, many customers may choose to install smaller heat pumps and rely to a greater extent on electric resistance heating as backup. While this approach may reduce customer installation costs, it may result in higher upstream electricity costs in the long run as the electricity generation, transmission, and distribution systems would need to be sized to accommodate additional electric load from resistance heating in the winter.

Maine should take steps to discourage customers from relying too heavily on electric resistance heating as a backup, either by incentivizing the installation of larger heat pumps or aligning residential retail rates with underlying system costs to convey a price signal to customers, so that customers who do choose to rely on electric resistance heating make an informed decision to bear the upstream supply cost.

3. Load Flexibility is a Cost-Effective Approach to Reducing Peak Loads

Flexible loads can help the electricity system adapt to short-term variations in available intermittent renewable energy (wind and solar). The Core pathway, which incorporates a substantial amount of within-day load flexibility, has materially lower requirements for electricity infrastructure and thus lower overall cost than the No Flexible Load pathway. The High Load Flexibility pathway performs even better on these dimensions. Flexible load cannot by itself balance the entire system, but flexible load can help meet the system's short-term balancing requirements while limiting the additional infrastructure needed. Importantly, the availability of load flexibility will increase substantially in the future, with new beneficial electrification loads playing a key role.

EV charging can play a critical role in implementing load flexibility since it will be a very large load in aggregate (projected to make up about one-third of electricity demand by 2050), and it is inherently flexible. In contrast with traditional electric loads that require electricity when the end use application is deployed (e.g., lights and toasters), charging EV batteries must occur when the vehicle is not being utilized. Most EVs will be idle and available for charging in most hours of the day, and charging will require only a small share of those hours.[146] EV charging at residential locations overnight or at workplaces during the day can often be delayed by 2–8 hours, facilitated by Level 2 chargers that can concentrate charge time into a few hours. Additional flexibility, as with vehicle-to-grid (V2G) operations that allow the EV battery to serve as a resource for the power system in extreme conditions, is also possible (stationary customer-sited batteries have some similarities).[147] Thus while EV adoption is not a direct focus of the requirement for 100% clean electricity by 2040, it is important because of the key role that flexible EV charging will play in enabling the grid to operate reliably with high renewable penetration, and limiting the infrastructure expansion necessary.

To support effective load flexibility, Maine should enable EV managed charging programs that leverage the experience of other utilities, automakers, and managed charging programs.[148] Maine and its utilities should leverage the work by Efficiency Maine on load flexibility to identify other opportunities for increasing load flexibility on its system, including behind-the-meter storage, virtual power plants, demand response, and time-of-use rates.[149]

The pathways analysis also explores the adoption a higher level of DERs combined with high load flexibility. The "High DER + High Flex" pathway shows that increasing the amount of behind-the-meter solar and storage further mitigates the electric system peak lowering distribution costs. This pathway also indicates that DERs should be deployed strategically to improve their benefits. The underlying challenge for distributed solar is the cost of development. As solar panel and inverter prices have plummeted over the last two decades, the "soft costs" related to design, permitting, installation, and customer acquisition have remained high, relative to utility-scale solar. Today, residential solar costs about three times as much per-watt as utility-scale solar, with about half of the total cost of residential PV coming from soft costs.[150]

There are two approaches that may improve the benefit-cost ratio of distributed solar:

- **Decreasing costs.** Streamlining the permitting and interconnection process can reduce soft costs for behind-the-meter solar. Some states have also experimented with mandating storage in new construction, which results in rolling the permitting cost into construction costs. Another option is expanding community solar, which can reduce unit development costs by taking

[146] Some other loads, such as heat pumps and water heaters, may also be somewhat flexible, though these are often smaller loads and typically cannot be shifted as much in time.

[147] This does raise additional considerations—e.g., safety considerations if V2G is feeding power back to the grid in an outage situation.

[148] Smart Electric Power Alliance. "Managing Charging Programs: Maximizing Customer Satisfaction and Grid Benefits."

[149] Efficiency Maine. "Innovation Program."

Hledik, et al. The National Potential for Load Flexibility: Value and Market Potential through 2030. June 2019.

[150] NREL. "Solar Installed System Cost Analysis.

advantage of economies of scale, while still building out solar capacity close to load.

- **Increasing value.** Maine can encourage developers to target specific opportunities where the addition of solar and storage can help defer substantial distribution system upgrades. This would require implementing targeted Non-Wires Alternative (NWA) programs to identify these opportunities and provide incentives to projects that defer costly upgrades. As the rate of load growth increases, the incidence of such opportunities is likely to rise as well. On the other hand, because of the scale of ultimate load growth, much of the distribution and transmission system will need to be substantially upgraded anyway, regardless of DER-enabled load shaving, which suggests this may often defer but seldom avoid upgrades.

C. Overarching Topics

1. Consider Equity Impacts

Maine Won't Wait identified equity as one of the plan's four primary goals: "Advance Equity through Maine's Climate Response." One of the primary issues in this regard for Maine's clean energy transition is to ensure that low- to moderate-income (LMI) customers are protected from undue cost increases for energy and energy infrastructure. In Maine, to an even greater extent than in other states, the primary focus is on electric sector costs, since Maine has relatively limited reliance on natural gas.[151] The pathway analyses demonstrate that electricity rates are likely to be stable and perhaps decreasing, since increases in infrastructure costs are projected to be offset by a corresponding increase in electricity sales. But although rates will be stable, electricity consumption will increase for most customers, resulting in generally higher overall electricity bills. Much of this increased electricity cost will be offset by reductions in other energy costs—e.g., from reduced motor fuel and heating oil consumption, at least on average.

Perhaps more importantly from an equity perspective, the conversions necessary can involve significant initial costs for customers, and these may create a particular barrier to adoption and an economic burden for LMI customers. For example, electrified heating requires purchasing and installing heat pumps, and may also require building modifications (building shell improvements, ductwork, electrical and physical building modifications to accommodate the new equipment). Similarly, adopting an EV may involve a higher initial vehicle cost than an ICE vehicle,[152] and requires installing a charger, which may trigger a need for electrical upgrades.

Unaddressed, these barriers might not only create challenges for LMI customers themselves, but could also threaten Maine's overall progress toward eliminating GHG emissions by limiting adoption rates. There are about 121,000 customers in Maine who qualify for the Low-Income Assistance Program (LIAP),

[151] Where natural gas is prevalent, cost increases are often a particular issue in that sector, since LMI customers may have greater difficulty leaving the gas system (e.g., because of an inability to afford the up-front costs of electrifying with heat pumps). Further, gas rates may increase, perhaps dramatically, as the largely fixed costs of the gas system are spread across fewer customers and lower gas volumes. This is less of a problem in Maine than in most other jurisdictions, at least in terms of numbers, because few residential customers in Maine rely on gas; most rely on fuel oil or other delivered fuels. Still, for affected customers, this may be an important issue as well.

[152] There is currently an initial cost premium for an EV over an ICE vehicle, though that premium is diminishing and may soon vanish.

which is available to customers making less than 150% of the federal poverty level.[153]

Where possible, Maine should develop policy mechanisms to help ease the burden of these initial costs on LMI customers, both to facilitate adoption among LMI customers in the first place, and to ease the financial burden when they do.

An initial step is to characterize the magnitude and the distribution of these effects, investigating and understanding the particular issues faced by LMI customers. Depending on the issues and barriers that are deemed most important, specific policy mechanisms can be designed to address these challenges. These might take the form of income-qualified grants, low-cost financing, and information and technical assistance to help citizens to understand the new technologies, their requirements, benefits, and trade-offs. Information and assistance programs will likely be applicable to all customers, though LMI customers may see particular benefits, as they may have fewer alternative pathways to access these. Efficiency Maine's rebates for income-eligible households aim to improve the affordability of heat pumps, insulation, water heating, and electric vehicles.[154] Maine also received federal funding from the Department of Energy through the Inflation Reduction Act, which will provide rebates for heat pumps for income-eligible households in new affordable multifamily housing and mobile homes and for efficiency upgrades in existing multifamily housing.[155] These measures can help to ensure access to transition opportunities, which will assist LMI populations directly and facilitate achieving the state's overall climate goals.

The Maine Climate Council and its Equity Subcommittee are already beginning to address these issues, setting goals, and tracking early progress, as reflected in the Maine Climate Council's December 2023 Annual Report, which summarizes progress on equity outcomes.

Other factors to consider in the transition include the siting of new facilities (and decommissioning of old facilities), taking into account in particular the impacts on vulnerable populations. This energy transition presents an opportunity to begin to undo some of the legacy of traditional energy infrastructure, which was often sited nearer to and had a greater impact on vulnerable populations.

2. Address Barriers to Adoption

Our analyses have assumed that the changes needed to achieve Maine's renewable, clean energy, and GHG reduction goals would occur at the pace specified in the various pathways. But there may be barriers and challenges to implementing the rapid changes necessary across the complex and widespread energy systems, and different pathways may encounter barriers of different types and to varying extents. If not overcome, these challenges may limit penetration or delay the rate of transformations, thus delaying the achievement of Maine's goals. There may also be risks associated with some pathways relating to the levels of clean energy utilization, even if technologies are adopted on the targeted schedule (for example, Hybrid Heat may reduce fuel use by less than expected, even if a target number of hybrid systems is installed, depending on how they are operated).

Barriers may arise for both customer end-use technologies (heat pumps, EVs, electric water heaters) and supply-side technologies (renewable

[153] For an average household in Maine, the federal poverty level is about $20,000 per year. Source: State of Maine Electric Ratepayer Advisory Council. "Second Annual Report," December 1, 2023.

[154] Efficiency Maine, How to Take Advantage of Efficiency Maine's Rebates for Income-Eligible Households, Accessed December 18, 2024.

[155] Efficiency Maine, Inflation Reduction Act Home Energy Rebates Program, Accessed December 18, 2024.

generation, storage, transmission, carbon-neutral fuels). Some types of barriers that may impede adoption/transition include:

- Initial and overall cost—for both end-use and supply technologies
- Inconvenience/disruption to customer (e.g., installing heat pumps)
- Limited customer familiarity, information and/or trust with alternative technologies (e.g., electrified end uses such as heat pumps and EVs)
- Preference among some customers to retain existing fuel-based systems
- Simple inertia—even willing customers may not adopt as quickly as anticipated
- Land use, siting, and permitting delays and barriers. (Permitting processes will be considered by the Governor's Energy Office in developing the Maine Energy Plan.[156])

To achieve the penetration rates and levels characterized in the pathways, and keep the overarching policy goals on schedule, it will be necessary to identify and anticipate these barriers, and to develop policy approaches to help overcome them. Below are some broad considerations.

- Rebates and cost assistance (as with some current state and federal programs) can defray initial costs to help overcome cost barriers. This will likely require additional funding from state and federal (and perhaps local) authorities, via utility programs, etc. Given the magnitude of initial costs and the number of installations (e.g., for heat pump deployment), the overall cost of rebates and subsidies needed to achieve the necessary adoption rates may be substantial. Since not all customers face the same initial cost, nor do they have the same ability or willingness to absorb such costs, the threshold rebate necessary to incent adoption will vary from customer to customer, but fairness considerations may make it difficult to tailor rebates individually, which can further contribute to high program costs.
- A systematized approach may help to speed and coordinate customer adoption. That is, rather than reliance on individual customer initiative to drive the transition, it may be effective to adopt a more "managed transition" to systematically convert customers to electric heat pumps. A managed transition could be geographically targeted and coordinated, facilitating planning, and controlling when and where additional electric load will arise on the system, to help ensure the distribution system is prepared for the increased load. (Maine has limited natural gas use, so is less exposed than most other states to some of the network issues involved with gas distribution systems.) This could address several of the barriers noted above: reducing costs, improving customer familiarity with and information about new technologies, and helping to overcome inertia.
- Streamline land-use, siting and permitting policies, and processes, to reduce uncertainty and accelerate resolution. Long delays in the process not only delay implementation, but create uncertainty and directly contribute to increased costs, both of which further discourage timely development. (Section IV.A.3: Policymakers Must Continue to Modernize Transmission and Distribution Planning to Facilitate Clean Energy Goals above addresses some issues that arise in these contexts.)
- Consider the timing and sequence of adoption rates across the spectrum from supply to end use.

[156] Title 2: Executive, Chapter 1: Governor, §9. Governor's Energy Office.

Obviously, additional generation and transmission should be coordinated to enable full utilization of new clean resources, and to support powering new end-use loads. Rather than a series of incremental distribution upgrades over time to accommodate growing electrification loads, it may be more cost-effective to coordinate a single larger upgrade designed to accommodate long-term needs. A managed transition that provides some control over the rate and geography of adoption may facilitate this.

3. Invest in the Workforce Transition

Another issue, which creates a parallel opportunity, is that the transformation will create material workforce demands to install and maintain the end-use and supply-side infrastructure needed to facilitate Maine's clean energy transformation—heat pumps, EV chargers, wind, solar, and storage resources, transmission and distribution infrastructure, etc. If the requisite workforce is not developed, or is not able to perform well, this could become a barrier to implementing the transformation in the timeframe of the state's goals. On the other hand, this transformation creates an opportunity to target employment toward vulnerable populations who may otherwise lack good opportunities, sharing the economic opportunities broadly at the same time as helping to remove a potential barrier to the state's GHG reduction goals. These are long-term opportunities. The transition itself will involve installing new and upgraded infrastructure over a period of several decades, and beyond this, it will be necessary to continue to maintain and ultimately replace the infrastructure. Targeting employment to vulnerable populations may take the form of career advice, training programs, on-the-job training, coordination with local employers, etc., and can be administered by local colleges and technical schools, focusing where possible on vulnerable populations.

4. Regional Coordination and Cooperation

Although the connections are not explicit in the pathways modeling described above, regional coordination and cooperation will be necessary for Maine to achieve its clean energy and GHG reduction goals.

- **Power System Generation and Transmission Investments**: As noted above, regional transmission planning must continue to evolve to identify the necessary upgrades to support a cost-effective clean energy transition and build out the system accordingly. Regional coordination will facilitate more effective and lower-cost transmission solutions and allow states to diversify the clean energy resources needed. In addition, multi-state solicitations for larger renewable generation resources, especially for a smaller state like Maine, will enable greater economies of scale, reducing costs to customers. Competition for regional clean resources does not achieve Maine's or other states' ultimate goals, even if, viewed in isolation, it might appear to make progress toward an individual state's goals. Other New England states may be interested to coordinate with Maine on floating offshore wind projects in the Gulf of Maine. The 3 GW that Maine has committed to for its own use is a small share of the 32 GW of generation the area could support, and increased scale for both the generation and the necessary transmission interconnections and upgrades may reduce overall costs, to the benefit of Maine and potential regional partners.[157]

[157] Bureau of Ocean Energy Management. "Gulf of Maine." Accessed June 25, 2024.

- **Power System Operations**: Evolving ISO-NE operational policies should address changing system needs. Since other New England states are also pursuing deep reductions in greenhouse gas emissions, there may be a premium on regional renewable resources to meet the growing demand from many states, and no state will be able to "lean on" a fossil-dominated ISO-NE grid indefinitely. In the end, any one state decarbonizing its economy in isolation will not address climate goals, since climate is a global issue and each state is a small contributor to the solution. Maine, like each of the other New England states, must do its own share to address emissions, and must coordinate with other states to help them do their share as well, to have a significant impact on global emissions.

- **Electric Vehicle Adoption**: Due to the proximity of southern Maine's population centers to other New England states, Maine drivers frequently travel into the rest of New England. They will need to be able to rely on those states having adequate EV charging infrastructure to adopt and utilize EVs at the rate needed, and the same is true for drivers in the other New England states traveling to Maine. Regional cooperation in building out sufficient EV charging capacity along major transportation corridors and at final destinations, such as hotels and in vacation areas, will be essential to overcome concerns about the lack of charging infrastructure for longer trips.

- **Heat Pump Adoption**: Maine has become a leader in the adoption of cold-climate air-source heat pumps and can help other states understand the capabilities of these resources and the challenges faced in their adoption. Coordinating with other New England states on their initial efforts to support heating electrification can help Maine identify additional approaches meet its expanded goal for heat pump adoption.

V. Conclusion

This report analyzes how Maine can achieve its GHG emissions reduction and clean energy goals: reducing its dependence on oil, utilizing 80% renewable electricity by 2030, procuring 100% clean electricity by 2040, and achieving carbon neutrality by 2045. It integrates the latest data and analyses on renewable energy technologies and markets, end use equipment, and GHG emissions accounting, leveraging feedback from key stakeholder groups and the broader public. The modeling considers key energy uses across sectors, identifying the year-by-year investment and operational decisions that satisfy energy demands while achieving Maine's policy goals, at the lowest cost. The analysis explores several alternative stylized pathways by which Maine can achieve its policy goals, comparing these pathways to offer insights into the relative advantages and costs of alternative approaches. These pathways inform a set of recommendations that Maine policymakers can use to guide legislative and regulatory efforts.

The study identifies several key high-level results:

- Widespread electrification of end uses, particularly transportation and heating, combined with transitioning to clean electricity supply, will be necessary, and will achieve both Maine's GHG reduction goals and its 2040 goal of 100% clean electricity.

- Overall energy supply costs will remain generally stable; fuel expenditures will fall, and electricity expenditures will rise as electricity substitutes for fuels as Maine's primary source of energy.

- Thermal electricity generators powered by clean fuels can facilitate matching supply to demand, and currently appear likely to be lower cost, though must be utilized sparingly, only when needed. On the other hand, long duration energy storage technologies are improving and could potentially become more cost-effective than thermal resources. The criteria for clean resources have not yet been defined in Maine, but should be specified relatively soon, to ensure that there is time to plan and develop these resources in an orderly fashion. A broad definition of what qualifies as "clean" will facilitate the use of the most effective technology.

- There may be potential benefits to retaining some legacy heating systems to be used for backup heating, but the control technology required to efficiently dispatch these systems is not currently available. Maine should encourage the development of integrated controllers that can operate mini-split heat pumps in tandem with legacy oil boilers. These controllers would ideally also be able to respond to dispatch signals from the utility or system operator.

- Load flexibility, particularly for flexible EV charging loads, will play a key role, helping to limit infrastructure needs for supply, transmission, and distribution resources, and therefore keeping costs down. It is important for utilities to begin developing the capability to manage flexible load now so that they can build experience for the future.

Maine has already made substantial progress to transition its energy system and is well-positioned to achieve its clean energy and GHG reduction goals, though the transition is just getting underway, and the state must maintain and build on its early momentum. In the power sector, Maine has committed to offshore wind development, the Northern Maine Renewable Energy Development Program, and additional solar initiatives that together will fill much, though not all, of its clean electricity needs. The state must follow through on these procurement commitments and will also need to fill the remaining gap, either with additional procurements or REC purchases. Maine has also made good progress on installing heat pumps, and must continue and accelerate this trend, as well as ensure that heat pumps are utilized properly so that they displace most heating fuel use in the long run. It will also need to ensure widespread adoption of EVs and the development of sufficient charging infrastructure for them.

As Maine actively encourages electrification of transportation and heating, it must prepare its electricity system for the associated load growth. In addition to developing new clean electricity generation resources, this will involve upgrading transmission and distribution infrastructure. Maine should focus on enabling the development of this infrastructure through incentives, education, and workforce development, and may require systematic transition programs to support widespread penetration.

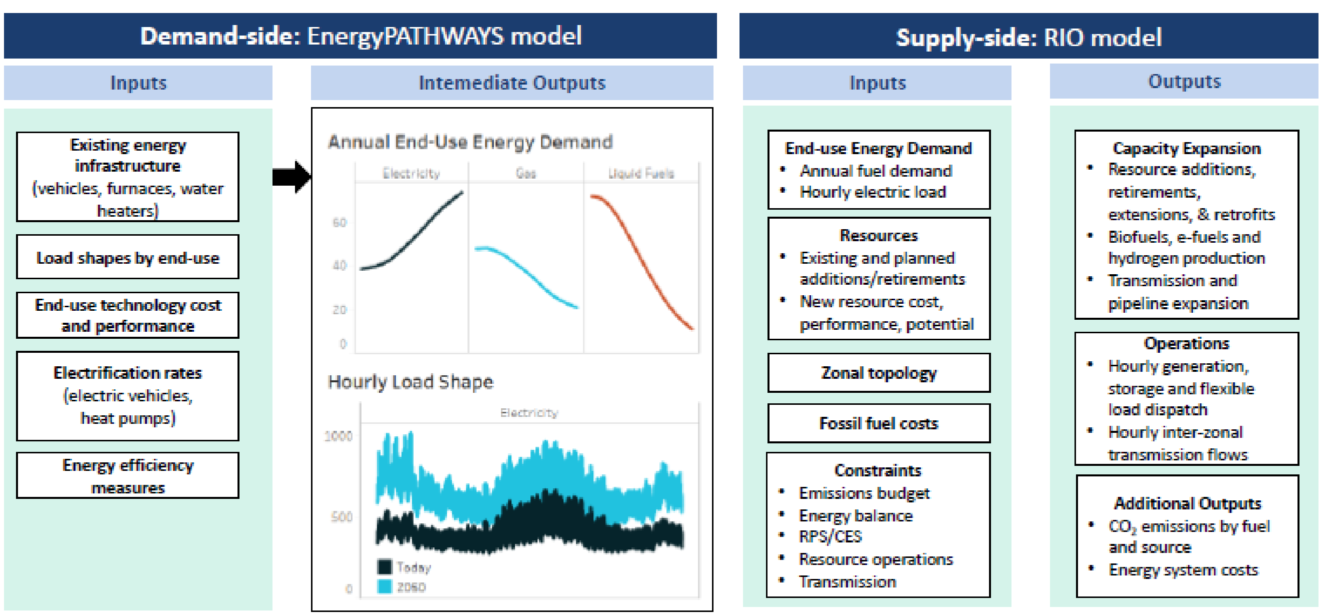
Appendix A: Detailed Description of Pathway Modeling Approach

The modeling approaches couples two models: EnergyPATHWAYS and Regional Investment and Operations model (RIO) (Figure A-1). EnergyPATHWAYS produces demand-side scenarios that result in fuel demand, electricity demand (hourly), and flexible load. RIO then optimizes supply-side energy decisions subject to emissions and clean energy constraints to meet these demands for a coherent whole-economy pathway that includes a full accounting of all potential energy system decisions.

EnergyPATHWAYS focuses on detailed and explicit accounting of energy system decisions. These decisions are made by the user and are inputs to the model as a set of potential future scenarios. In contrast, the RIO platform is an optimization that finds the set of energy system decisions that are least cost.

These different approaches were chosen because demand-side decisions are typically unsuited to least cost optimization because they are based on many socioeconomic factors that span the economy and are better examined through scenario analysis. Influences on adoption are myriad and often not economic. For example, light-duty vehicle adoption is partially an economic choice, but also reflects consumer preferences, vehicle model availability, rate design, and charging infrastructure decisions. Scenarios can explore different light-duty vehicle adoptions to test different policy assumptions and understand how those demand-side changes interact with a least-cost energy-supply portfolio.

FIGURE A-1: PAIRED MODELING APPROACH



A.1 EnergyPATHWAYS

EnergyPATHWAYS and its progenitor PATHWAYS have been used since 2014 to analyze energy system transformation starting in California (California ARB) before expanding to U.S. wide analysis (2014 U.S. DDPP, Risky Business, NREL Electrification Futures Study, Princeton Net Zero America and REPEAT, and many others) and additional state and regional work (most states and regions in the U.S. including state energy plans for New Jersey, Washington State, and Massachusetts). The model has also been used internationally in Mexico, Canada, Europe, and Australia. In each context, it has excelled by elucidating changes in the energy system at a level granular enough to be recognizable by policy implementers looking at sectoral and sub-sectoral impacts.

EnergyPATHWAYS is a bottom-up stock-rollover model of all energy-using technologies in the economy, employed to represent how energy is used today and in the future. It performs a full accounting of all energy demands in the economy, including feedstocks, and can be used to represent both current fossil-based energy systems and transformed, low-carbon energy systems. With over 380 demand-side technologies, the model is able to explore myriad dimensions of a low carbon energy transition.

Inputs to determining final energy demand include:

1. Demand drivers—the characteristics of the energy economy that determine how people consume energy and in what quantity over time. Examples include population, square footage of commercial building types, and vehicle miles traveled. Demand drivers are the basis for forecasting future demand for energy services.

2. Service demand—energy is not consumed for its own sake but to accomplish a service, such as heating homes, moving vehicles, and manufacturing goods.

3. Technology efficiency—how efficiently do technologies convert fuel or electricity into energy services. For example, how fuel-efficient a vehicle is in converting gallons of gasoline into miles traveled.

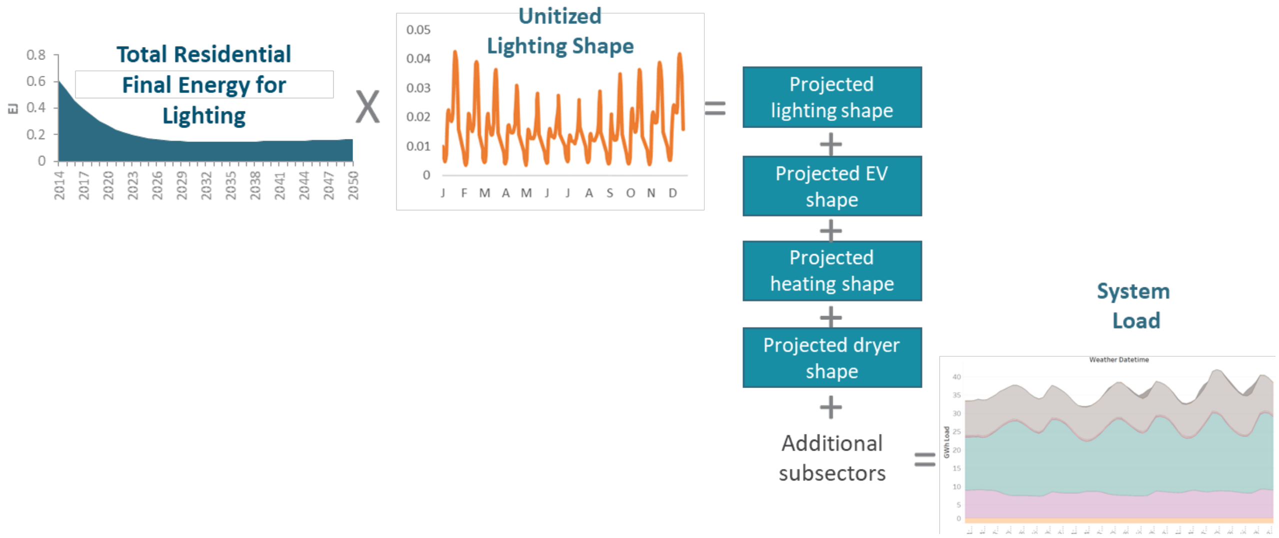
4. Technology stock—what quantity of each type of technology is present in the population and how that stock changes over time. For example, how many gasoline, diesel, and electric cars are on the road in each year.

The model has high levels of regional granularity, with detailed representations of existing energy infrastructure (e.g., power plants, refineries, biorefineries, demand-side equipment stocks) and resource potential.

EnergyPATHWAYS determines sectoral energy demand for every year over the model time horizon by dividing service demand by technology efficiency, taking into account the stock composition. Service demand and technology stocks are tracked separately for each study zone (study zones are shown in Figure A-9) and the aggregate final energy demand must be met by supply-side energy production and delivery, modeled in RIO.

Due to the importance of hourly electricity demand when planning and operating the electricity system, a final step is taken in EnergyPATHWAYS to build hourly load shapes bottom-up for future years, as illustrated in Figure A-2. Each electricity-consuming sub-sector in the model has a normalized annual load shape with hourly time steps. Electrical final energy demand is multiplied by the load shape to obtain the hourly loads of each subsector. These are aggregated to obtain estimates of bulk system load. Benchmarking is done against historical system load shapes and correction factors are calculated and applied to correct for bias in the bottom-up estimates. After calibration, the calculated bottom-up load-shape in the first year matches historical

FIGURE A-2: DEVELOPMENT OF HOURLY ELECTRICITY LOAD SHAPES



system-wide load. The same correction factors are carried forward and applied to future years.

EnergyPATHWAYS was used to forecast energy demand of all types, including electricity and fuels, as the stocks of energy consuming technology in the economy change with assumptions about electrification and efficiency. The forecasted energy demands were then put into the RIO platform to solve for how to supply that energy over the next 30 years.

A.2 Regional Investment and Operations (RIO)

On the supply side, least-cost investments in electricity and fuel production to meet carbon and other constraints are determined using a capacity expansion model called RIO. RIO is a linear program that optimizes investments and operations starting with current energy system infrastructure. It incorporates final energy demand in future years, the future technology and fuel options available (including their efficiency, operating, and cost characteristics), and clean energy goals (such as RPS, CES, and carbon intensity). Operational and capacity expansion decisions are co-optimized across the ten study zones.

Multiple timescales are simultaneously relevant in energy system planning and operations, and the emerging importance of variable generation (wind and solar) in future power systems means that high temporal fidelity in electricity operations has increased in importance. RIO decision variables and temporal scales are shown in Figure A-3.

The most important distinction between RIO and other capacity expansion models is the inclusion of the fuels system, making it possible to co-optimize across the entire supply-side of the energy system, while enforcing economy-wide emissions constraints within each zone. This is important for accurate representation of the economics when electricity is used for the production of fuels, for example when renewable over-generation is used for the production of hydrogen.

Energy system planning necessitates looking decades into the future over the lifetime of potential investments being made today. Adding to the inherent challenge is that those decades are almost certain to usher in a dramatic change in how electricity is consumed and produced: from the rapid penetration of low-cost renewables; to the

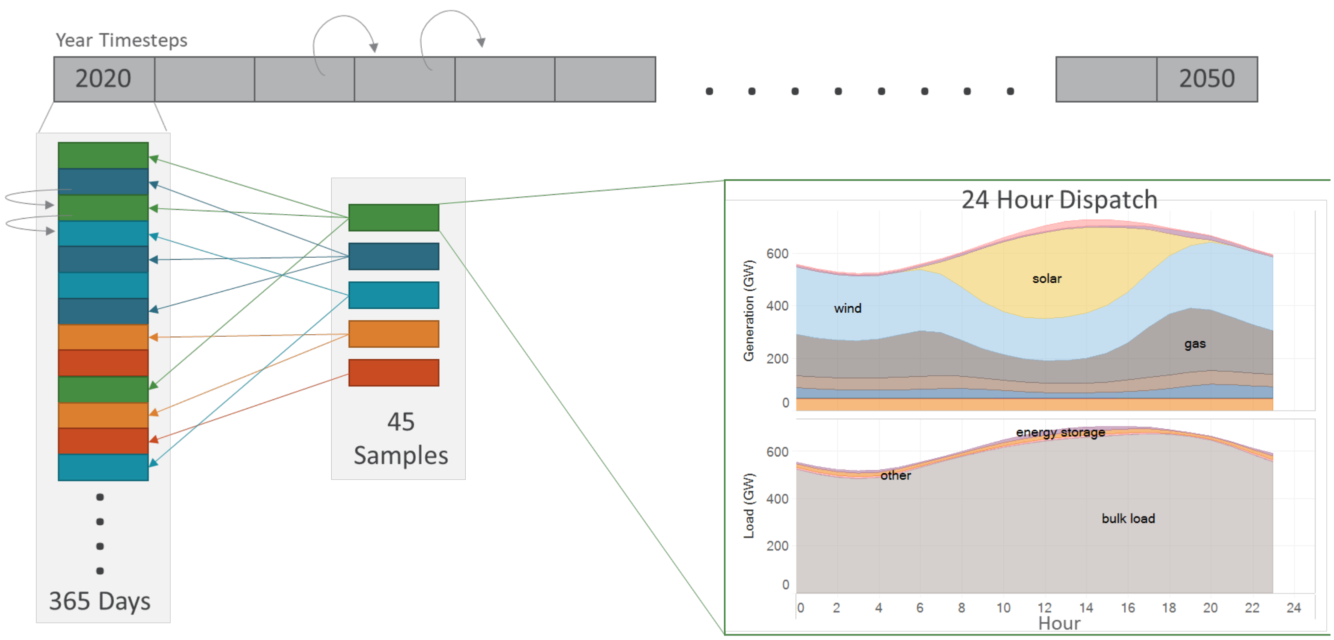
FIGURE A-3: RIO DECISION VARIABLES AND TEMPORAL SCALES

Decision Variables	Key Results
Generator Dispatch	Hourly Dispatch
Transmission Flows	Transmission Flows
Operating Reserves	Market Prices
Curtailment	Curtailment
Load Flexibility	

Decision Variables	Key Results
Fuel Energy Balance and Storage	Daily Electricity Balances
Long Duration Electricity Storage	Daily Fuel Balances
Dual Fuel Generator Blends	

Decision Variables	Key Results
Emissions from Operations	Total Annual Emissions
CES Supply and Demand	CES Composition
Capacity Build, Retirement & Repower	Incremental Build, Retirement, & Repower
	Thermal Capacity Factors
	Annual Average Market Prices
	Marginal Cost of Fuel Supply

FIGURE A-4: OPERATIONAL TIMESTEPS IN RIO



engagement of customers to provide demand-side flexibility to the system; to the deployment of new technologies that provide supporting grid services. The RIO platform can operate as the central platform of a modern planning framework, designed with the specific intent of better capturing the investment and operational dynamics of future systems.

RIO utilizes the 8,760 hourly profiles for electricity demand and generation from EnergyPATHWAYS but optimizes operations for a subset of representative days ("sample days") before mapping them back to the full year (illustrated in Figure A-4). Operations are performed over sequential hourly timesteps.

Clustering of days using several dozen features or diurnal 'characteristics' is used with careful attention to ensure that the sampled days represent the full range of conditions encountered in the historical weather year. The clustering process is designed to identify days that represent a diverse set of potential system conditions, including different fixed generation profiles and load shapes. The number of sample days impacts the total runtime of the model and trades off with the ability to represent a range of historical conditions. Across the zones, 66 sample days was found to strike the right balance, giving both good day sampling statistics and reasonable model runtimes.

Figure A-5 provides a full list of RIO features along with the specific configurations used here.

A.2.a Flexible Load

Flexible loads are end-use loads (electric vehicles, space heating, water heating, etc.) where there can be a delay in the delivery of electricity to a customer without incurring significant costs in terms of customer utility. This is referred to as "latent flexibility," though there may be necessary investments needed to unlock this flexibility (i.e., controls, thermal storage, smart meters, etc.). RIO models these flexible loads using flexibility envelopes parameterized with the share of end-use energy that is deemed flexible (analogous to customer participation rates) along with the number of hours this energy can be advanced (moved ahead in time from when demand would otherwise occur) or delayed (moved back in time). End-use loads are parameterized differently based on the inherent characteristics of the shape of the native service demand. EVs, for example, have a service demand shape based on a statistical assessment of the arrival time of uncharged batteries to chargers (i.e., the shape peaks when vehicles are likely to be arriving home with less than fully charged batteries). Given this definition, charging cannot be advanced from the native shape (i.e., moved ahead to a time before vehicles arrive home) but it can be delayed. For thermal end-uses, there can be advances or delays, reflecting the ability to pre-heat or pre-cool as well as the ability to delay demand for electricity by taking advantage of lags in temperature changes.

The sensitivity of these parameters was explored through scenario analysis. Figure A-6 describes the base assumptions and more aggressive flexibility assumptions (in parentheses) applied in other scenarios. The 'High' flexible load assumptions are used in both the High Flexible Load and High Distributed Resources scenarios and explore higher customer participation and technological advancements that could unlock more flexibility. In the case of heating and cooling this includes heat pumps with built-in thermal storage allowing for four hours of pre-conditioning. For light duty vehicles, this includes a limited amount of V2G and the ability to delay EV charging by up to 24 hours.

FIGURE A-5: LIST OF IMPORTANT RIO FEATURES AND PARAMETERS

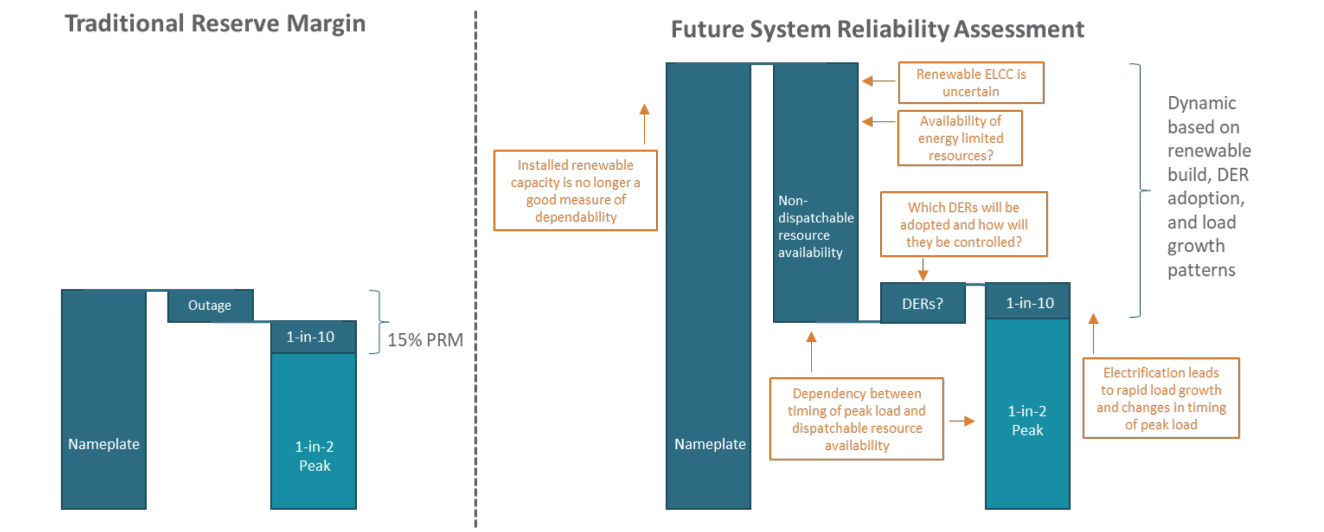
Feature	Settings used for the Maine Analysis
Optimal generator selection	Optimal selection of thermal, energy storage, and renewable resource capacity additions.
Optimal energy storage selection	Optimal selection of energy & capacity, priced separately.
Long duration storage	Tracking of long duration state of charge across 365 days.
Optimal transmission selection	Enabled for all existing paths and Quebec to Maine. Committed transmission lines are placed in service in future years.
Optimal fuel technologies	Flexible framework allowing for selection and operations of any fuel conversion and supply infrastructure. Fuel conversions that consume electricity allowed to co-optimize operations with electricity generation.
Fuels storage	Optimal build and state-of-charge tracking over 365 days for hydrogen.
Dual fuel generators	Existing and new gas generators capable of burning up to 100% of natural gas or carbon-free synthetic natural gas, as well as up to 60% hydrogen.
Flexible load	Load shifting and a detailed framework with cumulative energy constraints for end-uses.
Number of zones	14 zones co-optimized in RIO
Number of resource bins	10 NREL technical resource group (TRG) bins for onshore wind, 14 bins for offshore wind and 1 bin for solar PV per zone.
Year time step	Model run for the years 2023, 2026, 2030, 2035, 2040, 2045, 2050.
Hours modeled per year	66 sample days (1,584 hours)
Weather years	Weather year 2011
Perfect foresight	RIO has perfect foresight because all model time periods are simultaneously solved.
Electricity reliability	Determined endogenously using an hourly reserve margin framework.
Renewable capacity value	Determined endogenously based on hourly operations.
Load shapes	Built bottom-up in EnergyPATHWAYS
Generator retirements	Announced retirements are enforced. Otherwise, retirement of generators before the end of their physical lifetimes is optimized with the benefit being savings in fixed O&M.
Generator repower/ extension	Solved endogenously. At the end of their physical lifetimes, generators can be repowered at (typically) lower cost than new construction.
Annual carbon emissions constraints	Maine energy-related CO_2 emission constraint of 11.0 $MtCO_2$ in 2030, 5.5 $MtCO_2$ in 2040 and 0.0 $MtCO_2$ in 2050. Proportional carbon constraints across other zones
RPS/CES	Maine 80% RPS by 2030 and 100% clean by 2040, including supporting procurements. Existing state policy across other zones.
Annual resource build constraints	Annual maximum builds by resource group defined with compound growth rates to represent supply-chain constraints
Cumulative resource build constraints	Potential constraints enforced for all renewables with data derived from the NREL ReEDS model.
Fuel prices	Specified exogenously for fossil based on the 2023 U.S. Annual Energy Outlook and with supply curves for biomass.
Biomass allocation	Determined endogenously between electricity and fuels
Carbon sequestration/use allocation	Determined endogenously between electricity, fuels, and industry

FIGURE A-6: FLEXIBLE LOAD PARAMETERS

End-use	# hours load can be delayed	# hours load can be advanced	% of load that is flexible
Air conditioning	1 (1)	1 (4)	10% (50%)
Space heating	1 (1)	1 (4)	10% (50%)
Water heating	2 (2)	2 (2)	10% (50%)
Battery electric vehicle (residential feeder)	8 (24)	0 (0)	67% (100%) (V2G)

Note: The values that are not in parentheses are the base assumptions, and the values that are in parentheses show the High flexible load assumptions.

FIGURE A-7: RELIABILITY FRAMEWORK IN HIGH RENEWABLE SYSTEMS



A.2.b Reliability

The conditions that will stress electricity systems in the future and define reliability needs will shift in nature compared to today, as shown in Figure A-7. Capacity is the principal need for reliable system operations when the dominant sources of energy are thermal. Peak load conditions set the requirement for capacity because generation can be controlled to meet the load and fuel supplies are not constrained. As the system transitions to high renewable output, the defining metric of reliability need is not just peak load but net load (load net of renewables). Periods with the lowest renewable output may drive the most need for other types of reliable energy even if they do not align with peak gross load periods. In addition to that, resources will become increasingly energy constrained. Storage can only inject the energy it has in charge into the system. Reliability is therefore increasingly driven by energy need as well as capacity need.

In the future, the defining reliability periods may be when renewables have unusually low output, and when that low output is sustained for unusually long periods. To model a reliable system in the future, both capacity and energy needs driven by the impact of weather events and seasonal changes on renewable output and load need to be captured.

To ensure we capture the impacts of these changing conditions on reliability, we enforce an hourly reserve requirement across all modeled hours. This “planning demand” is found by scaling load up to account for the fact that a 1-in-10 peak load will be larger than the loads sampled from a single weather year (15% used based on empirical analysis). In the same hours, a dependable contribution of each resource to meeting the planning demand is calculated. Dependability is defined as the output of each resource that can be relied upon during reliability events. The planning demand must be met or exceeded by the summed dependable contributions of available resources in each hour.

A.2.c Dependability

The dependable contribution from thermal resources is derated nameplate, reflecting forced outage rates. Renewable dependable contribution is the derated hourly output, reflecting that renewable output will at times be lower than what the sample days reflect. For energy constrained resources such as hydro and storage, dependable contribution is their hourly output derated by outage rates. By using derated hourly output we can capture both the risk that it is not available because of forced outage, and the risk that it is not available because it has exhausted its stored energy supply. Transmission dependability factors depend on the path and reflect transmission line contingencies and the resource constraints of an exporting zone. Dependability factors are shown in Figure A-8.

A.3 Model Topology

Both EnergyPATHWAYS and RIO can be flexibly configured to run on any geographic granularity supported by the data. While the project is focused on policy recommendations for Maine, the interconnected nature of the electrical system requires consideration of surrounding states, the broader Eastern U.S. energy system, and national markets for fuels.

To accomplish this, we use a state-level transmission model of states surrounding Maine to accurately capture the dynamics of energy flows in the electricity sector. This model topology allows us to capture the impact of how policy in other states can impact decision making in Maine. These include energy flows, transmission needs, and resource availability, along with potential impacts of energy demand on the fuels sector.

RIO also has the functionality to trade fuels between different states. Hydrogen, hydrogen-derived clean fuels, and biofuels manufactured in one state can be traded to another allowing for cost optimal fuels allocation over the modeled region. When doing so the model uses a physical pipeline network representation, ensuring that the capacity of the pipeline is not exceeded. Optimal expansion of the pipeline network between states is part of the optimization.

FIGURE A-8: DEPENDABILITY FACTORS WHEN ENFORCING RIO RELIABILITY CONSTRAINTS

Resource	Dependability
Existing Thermal Resources	93% applied to nameplate
New Thermal Resources	93% applied to nameplate
Transmission	70% applied to hourly flows
Energy storage	95% applied to hourly charge/discharge
Variable generation (wind & solar)	80% applied to hourly output
Electricity load	106% applied to hourly load

The EnergyPATHWAYS and RIO models represent Maine with four zones: (a) three zones consistent with ISO-NE system planning (SME/ME/BHE); and (b) one zone in northern Maine (NMISA) connected to New Brunswick. Additional modeled zones include other ISO-NE states, New York, New Brunswick, Quebec, rest of Eastern Interconnection and rest of the U.S.

A map of the analysis geographies is given in Figure A-9. Transmission flows and capacity expansion were economically determined across multiple transmission paths in the region. Maine is directly interconnected to New Hampshire, Quebec, and New Brunswick. For the U.S. zones, EnergyPATHWAYS and RIO scenarios were developed specifically for this study. In Quebec and New Brunswick, electricity load shapes developed in EnergyPATHWAYS in 2018 as part of the North American Renewable Integration Study (NARIS), conducted in partnership with NREL,[158] were used.

For Northeastern states, each pursuing aggressive climate policy in an interconnected system, the regional context is essential for understanding any single state. This is becoming more critical over time as renewables emerge as the leading strategy for eliminating emissions from the electricity sector because of the benefits of geographic diversity in a high renewables electricity system. Northeastern states have a common set of resources to select from, and potentially to compete over, when decarbonizing (for example, imports from Quebec, sites for building wind generation, or zero carbon fuel imports). Thus, the availability and robustness of any strategy depends, in part, on what other states are doing.

Assuming collective action generally creates boundary conditions in decarbonization modeling exercises that increase its difficulty.[159] For example, one state could decarbonize by making fuels with any available biomass in the region but would encounter problems if all the states attempt to implement the same strategy. Similarly, one state might be able to run a deeply decarbonized economy by building out offshore wind in only the richest, most accessible, least expensive lease areas, but if every state in the Northeast sets similar renewable generation goals, that low-hanging fruit would be quickly exhausted.

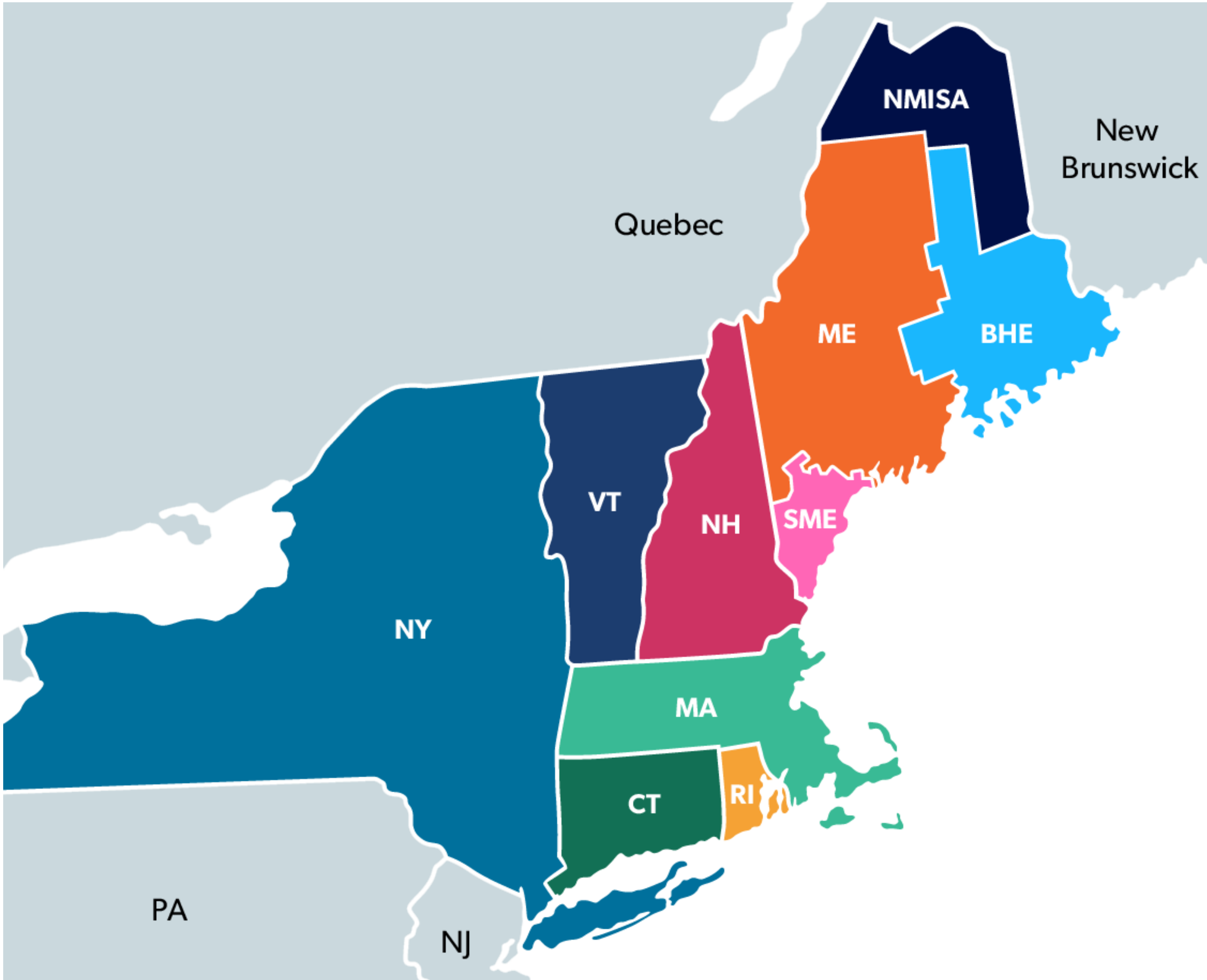
States must assume that eventually all neighboring jurisdictions share common targets. This removes logical inconsistencies in the energy system transition and helps ensure any decarbonization strategies do not inadvertently depend on collective inaction (as would be the case if a strategy was unable to be universalized). For this reason, this analysis assumed the percent reduction between 2020 and 2050 in energy CO_2 emissions across all zones eventually coalesce around net-zero by 2050, even if some Northeastern state policies do not currently reflect this ambition.[160]

158 NREL, North American Renewable Integration Study.

159 Not considered here is the fact that learning—technical and institutional—is likely to accelerate with collective action, leading to reductions in the cost of energy system transitions.

160 Because Maine remains this study's focus, this study did not quantify non-CO_2 and land related emissions across each zone to determine whether each zone achieved net-zero.

FIGURE A-9: MODELED STUDY ZONES IN U.S. NORTHEAST



A.4 Cost Methodology

The cost estimates for the decarbonization pathways are derived using a suite of methodologies that cover the whole energy system. Figure 54 provides a list of the cost calculation methods for each component of the energy system, along with examples.

The gross system costs presented in the report shown include capital and operating costs for anything that produces or delivers energy along with incremental costs above the baseline for demand-side technologies. Costs incurred outside of Maine (fossil fuel refining) for energy products consumed within Maine are allocated along with consumption. Also shown are net system costs, which focus on differences between gross system costs between two pathways. Here we use the Core pathway as the comparison point for all net cost calculations.

All costs are assessed on a societal basis. This means, for example, that the cost of biomass in Maine is summed up for each price tier of the biomass supply curve, as opposed to being calculated based on the marginal price of the final tier, as might happen in a market for biomass. Using the societal method is appropriate from a public policy perspective because, in this example, the market profits from biomass growers within the state are not a true cost, but rather a cost transfer. The same dynamic exists in electricity markets, where a societal cost approach is also taken. The societal cost here does not include explicit assessments of the different costs across members of society, where public policy is concerned with the distribution and equity of costs and benefits to across society. All cost inputs and outputs in this report are shown in 2022 dollars.

FIGURE A-10: LIST OF ENERGY SYSTEM COSTS INCLUDED IN THIS ANALYSIS AND THE BASIC METHODS USED FOR EACH

Supply/Demand	Fixed/Variable	Method	Costs	Examples
Demand	Fixed	Technology stock	Levelized equipment costs of all energy-consuming equipment in the economy represented at the technology level	Electric vehicles
Demand	Fixed	Generic cost per unit of energy saved	Incremental energy efficiency measure costs. Represents demand-side costs we do not have the technology-level data to support bottom-up.	Industrial energy efficiency measures
Supply	Fixed	Technology stock	Levelized equipment costs of all energy producing, converting, delivering, and storing infrastructure in the economy represented at the technology level	Solar power plants; wind power plants; battery storage; hydrogen electrolysis facilities
Supply	Fixed/variable	Revenue requirement	Projected revenue requirements based on current revenue requirements, anticipated growth levels consistent with scenarios (i.e., growing peak demand) and type of costs (i.e., the costs can be fixed investments or variable costs that can decline with lower demand).	Electricity T&D costs; gas T&D costs
Supply	Variable	Commodity costs	Costs based on exogenous unit cost assumptions	Biomass, fossil gasoline, fossil diesel, natural gas, etc.

A.5 Key Data and Assumptions

Figure A-11 summarizes the assumptions used across important inputs in the modeling.

FIGURE A-11: SUMMARY OF KEY ASSUMPTIONS

Data Assumption	Summary
Weather year	Weather year 2011 is used for presentation of all results. Projections of annual average heating and cooling degree days include the impacts of a warming climate as estimated in the U.S. Annual Energy Outlook.
RIO day sampling	66 sample days each for the snapshot years 2023, 2026, 2030, 2035, 2040, 2045, 2050.
Fuel conversion cost and potential	Compilation of public techno-economic studies with cost declines observed for many technologies. Data is summarized in the Excel input catalog. Biomass potential from DOE 2016 Billion Ton Report but excluding any new land for purpose grown bioenergy crops.
Carbon sequestration	NETL Supply Curves by model region. No potential in the Northeast.
Building heating costs & performance	Home heating system size based on the NREL ResStock model and heat pump cost derived from DOE and NREL sources. Commercial heating based on the NEMS model.
End-use load shape profiles	A variety of sources. For space heating, regressions using the ResStock and ComStock models are used to map to a 2011 weather year. The EVI-Pro tool is used for light duty vehicle charging profiles.
Electric & gas delivery infrastructure assumptions	Escalation or retirement of existing financial stocks based on assumed ratios between peak/throughput growth and revenue requirement growth. Calculations are done by customer class.
Generator cost and potential	Cost and performance based on NREL Annual Technology Baseline (ATB) 2023 with regional cost multipliers by technology.
Behind-the-meter solar PV	Minimum behind-the-meter solar growth trajectory based on ISO-NE projections and accelerated adoption in the High Distributed Resources scenario.
Hydro-Quebec operational constraints and expansion cost	Daily minimum capacity factors of 30% and a maximum hourly ramp rate of 20% across all dispatchable hydro. Ability to shift hydro budgets between seasons. Expansion costs assumed from NREL ATB 2023.
Cost of capital & discount rates	Societal discount rate 3% real Demand-side: 6-8% real depending on the subsector Electricity generation technologies: 4-5.5% Fuels technologies: 8% real
Demand-side sales share assumptions	Made by assumption and iteration based on supply-side modeling. Varies by pathway.

A.6 Uncertainties

Here we describe some general uncertainties that apply to any pathways exercise, plus others that apply specifically to Maine.

A.6.a General Uncertainties

The first important point is to reiterate that none of the pathways in this study are forecasts. The energy system of the future will inevitably turn out differently than whatever is analyzed here. Aspects that we may not have considered at all will influence how the system evolves in yet unimagined ways. As a thought experiment, consider what strategies a decarbonization plan formulated in the year 1990 would have emphasized; the world's first offshore wind farm, a key strategy presented in this work, was still a year away from construction in Denmark. The value of this study lies not in creating a rigid blueprint as the basis of an unvarying 30-year plan, but in informing the public and decision makers based on the state of current knowledge. Pathways have been used most successfully in recent years through a process of periodic updating—a dynamic in which near-term decisions are informed by the long-term perspective, while the long-term perspective is continually updated based on newly emerging information.

Second, decarbonization pathways studies by their nature focus heavily on the physical transitions of technology and infrastructure but ignore many human and institutional factors because of the difficulty of quantifying them and incorporating them into mathematical models.

FIGURE A-12: KEY AREAS OF UNCERTAINTY IN MODELING DECARBONIZED ENERGY SYSTEMS IN MAINE AND HOW THEY WERE ADDRESSED IN THE PATHWAY DESIGN

Uncertainty	Explanation	How addressed in modeling
Ability to site renewables	New England has been one of the most difficult locations in the U.S. to site renewables due to high population densities, expensive and disconnected land for development, and strong opposition to disturbances to natural lands.	State-level cost multipliers from NREL's ReEDS model are applied, resulting in higher costs for resources in the Northeast.
Ability to site transmission	The Northeast has seen many transmission projects delayed or canceled due to siting challenges. The ability to build transmission to connect renewables to load and to help balance renewables through geographic diversity are essential to scenarios with high wind and solar penetrations.	Transmission projects that have been built in the region are consistently some of the most expensive in the country. Pathways use pessimistic interregional transmission costs to discourage strategies that over-rely on potentially unachievable transmission builds.
Electricity operations in high wind and solar systems	The challenges arising in high renewable systems have been well documented. While technical solutions abound, exact cost and implementation details may not be known in advance.	These concerns are primarily addressed through careful design of the modeling tools used and ensuring that the designed electricity system is robust to periods in the historical weather record that correspond to very low renewable production.

Uncertainty	Explanation	How addressed in modeling
Customer adoption of electric and efficient technologies	Demand-side adoption of efficient and predominantly electric technologies are important pillars of energy system decarbonization. Yet, this adoption depends on customer decisions, which can be influenced through policy mechanisms such as incentives and mandates, but ultimately not controlled. This means any energy system transition is partially predicated on customer behavior regarding energy use, and not just policy to shape energy supply.	In this work, we studied alternative heat pump adoption scenarios, including: (a) adoption of primarily whole-home all-electric heat pumps; and (b) adoption of primarily fuel-electric hybrid heat pumps where boilers/furnaces provide heat on the coldest days. This work has not studied different rates of on-road transportation electrification, which will impact the cost and the achievability of Maine's state goals.
Load shapes for electric heating	Predicting future peak load from heating is sensitive to a set of uncertain factors. These include: (1) future heat-pump COPs at very low temperatures; (2) temperature, solar gain, and wind-speed distributions across the state; (3) heat-pump sizing practices; (4) use of supplemental electric heating; (5) customer set-points and willingness to participate in flexible load programs; and (6) improvements to building shells (infiltration, insulation, and thermal mass).	This analysis uses a sophisticated set of regressions developed from the ResStock and ComStock models, themselves a state-of-the-art examination of county-by-county building HVAC demand. The same methodology has been used across many other jurisdictions and benchmarked to past work in New England. 2011 was selected because it reflects a winter median peak load in the region.
Flexibility of end-use loads	Building and transport electrification applications are unique in the magnitude of inherent energy storage available (chemical in batteries and thermal in space and water heating). This means shifts in the timing of electricity consumption are possible with almost no impact to the customer and large cost savings. However, participation in these programs, the degree to which load can be shifted without affecting service, and exact systems for control are all uncertain.	Most pathways embed a moderate amount of flexible end-use load. The value of major breakthroughs in end-use load flexibility was quantified in the High Flexible Load and High Distributed Resources pathways. Variable cost of use are included to reflect the fact that ongoing customer participation is not free, even after building the enabling technologies.
Electric distribution cost increases from load growth	The cost impact of load increases on distribution systems is a hyper-local question that varies by circuit. Therefore, exactly how a doubling of load will impact the distribution revenue requirement is difficult to quantify when analyzed at a state level.	The approach taken in this study is to scale existing revenue requirements with increases in peak load by feeder (residential, commercial, & industrial). We assume a doubling of peak leads to an 60% increase in revenue requirement.
Low-carbon fuels	There is significant uncertainty in the availability, cost, and life-cycle impacts of low-carbon fuels (including bio- and synthetic liquid fuel and gas substitutes).	Availability and cost of biogenic-based fuels are bounded by the U.S. DOE's Billion Ton Study and Princeton Net Zero America Project. RIO uses the domestic production of synthetic fuels from, for example, captured carbon and electricity-derived hydrogen when economically competitive against alternative emissions reduction strategies. As a simplification, such drop-ins are considered to have a net zero carbon emissions profile.

Similarly, equity and distributional impacts between pathways are not quantified in this report. The energy data used to populate the EnergyPATHWAYS and RIO models are primarily state-wide aggregates, and as a result, the models can quantify impacts on the average household, but not, for example, households in a given zip code. Qualitative discussions of the distributional impacts are brought into the discussion where possible.

One valuable result from modeling a set of pathway sensitivities is the identification of commonalities between pathways. The common findings for the set of pathways run in this report are discussed in the results section. That said, the sensitivities that were modeled are by no means exhaustive, and the dimensions of the problem that are both important and uncertain are far more numerous than the number of pathways it was feasible to explore.

A.6.b Maine-Specific Uncertainties

The novelty of the energy system transformation imagined across the U.S. in this analysis requires many assumptions to be made in the modeling that are necessary but uncertain. Figure A-12 lists some of the largest uncertainties and the ways this analysis has tried to deal with them.

A.7 Established Track Record of Successful Planning Studies

EnergyPATHWAYS and RIO have been used in many successful engagements, including for long-term planning of electricity systems and the energy economy, for evaluation of clean fuels markets and development of a hydrogen economy, for asset evaluation in the context of electricity or energy system transformation, and for policy advising. They have been the engine behind many high profile decarbonization studies and energy analyses, including national studies such as assessment of the impact of the Inflation Reduction Act with the Princeton REPEAT project, state planning studies such as the New Jersey 2019 Energy Master Plan and the Washington 2021 State Energy Strategy, and NGO, utility, developer, and investor studies.

A.8 Details on EnergyPATHWAYS and RIO

Detailed descriptions of the EnergyPATHWAYS and RIO models are available on request. They are also available in the U.S. 2023 Annual Decarbonization Perspective: (https://www.evolved.energy/2023-us-adp).

Appendix B: Key Energy Technologies

This section offers a brief overview of technologies that may facilitate greenhouse gas emissions reductions in the energy sector, which represents ~91% of greenhouse gas emissions in Maine. The technologies described in this section are organized in two categories: Supply-Side Technologies and Demand-Side Technologies.

B.1 Supply-Side Technologies

B.1.a Solar

Solar photovoltaic technology has undergone massive price decreases. According to the International Energy Agency (IEA), the costs of solar modules have fallen from over $100 per-watt in 1975 to less than $0.20 per-watt in 2020.[161]

Recent growth of solar generation capacity has come in large part from utility-scale PV deployment, but the falling price of PV arrays also improves the economics of small distributed systems. As module prices fall, the costs of permitting and installing small-scale rooftop solar have come to represent a larger share of total project costs.[162] These "soft costs" make rooftop solar substantially more expensive on a per-unit basis than utility-scale solar and present opportunities for further cost reduction for distributed solar.[163]

B.1.b Wind

Like solar, wind power has seen an uptake in recent years. While solar panels are only productive during the day, well-placed wind turbines typically produce output at most hours of the day, with greater output at night. In this way, wind power complements production from solar.

In 2022, Maine generated 2,716 GWh of electricity from wind power, producing 21% of its in-state electricity supply.[164] According to the GEO's REGMA Study, Maine has substantial potential for additional onshore wind development, though this would require major investments in additional transmission infrastructure.[165]

In recent years, the size and height of wind turbines have grown dramatically, allowing for greater production per unit area of land. Simultaneously, there has been growth in development of offshore wind farms. While offshore wind is more costly to develop than onshore wind, offshore wind can be sited closer to load centers than onshore wind, decreasing the need for major transmission additions. Additionally, offshore wind has a more consistent output than onshore wind, resulting in a greater production. Maine has a goal of procuring at least

[161] For internal consistency, both estimates are reported in 2015 dollars. IEA, Evolution of solar PV module cost by data source, 1970-2020, IEA, Paris https://www.iea.org/data-and-statistics/charts/evolution-of-solar-pv-module-cost-by-data-source-1970-2020, IEA. License: CC BY 4.0.

[162] The National Renewable Energy Laboratory. "Documenting a Decade of Cost Declines for PV Systems." Accessed February 15, 2024.

[163] Klemun, Kavlak, McNerney, Trancik. "Mechanisms of hardware and soft technology evolution and the implications for solar energy cost trends," Nature Energy, 8, pages827–838 (2023).

[164] "Electricity Data Browser—Net Generation for All Sectors." Accessed February 15, 2024. Link.

[165] State Of Maine Office of The Governor. "2022 Maine Energy Summary and Assessment," March 15, 2022. https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/GEO_EnergyAssessment_2022_FINAL.pdf.

3,000 MW of offshore wind from new resource development in the Gulf of Maine.[166]

B.1.c Hydro

Hydropower has played an important role in Maine's economic development. Many communities in Maine and throughout New England used energy from local streams to run mills for grinding grain and sawing lumber. Maine was an important early adopter of hydroelectric power in the early 20th century and still runs hydroelectric facilities today that date back to the early 1900s.[167]

Hydropower is Maine's second-largest electricity source after natural gas, having produced 24% of the state's electricity supply in 2022.[168] The potential for additional hydroelectric power is quite limited, though, as many of the best hydroelectric sites are already dammed. Many large hydropower facilities can adjust their output based on demand, which make them valuable for balancing variable output from wind and solar plants.

B.1.d Nuclear

Today there are 54 nuclear power plants in the United States, the newest of which was completed in 1996.[169] In 2023, Plant Vogtle in Georgia opened a third reactor, the first new nuclear reactor to be added to an existing power station in 7 years, since the Tennessee Valley Authority began operation of its Watts Bar Unit 2 in 2016.[170] Nuclear power plant capital costs have been increasing in the United States due to rising construction costs.[171]

Maine does not have any operating nuclear power plants, though there are two still operating in New England: Millstone Nuclear Power Plant in Connecticut and Seabrook Station Nuclear Power Plant in southern New Hampshire (about 15 miles south of Maine's southern border). These have an aggregate generating capacity of 3.4 GW and provide reliable baseload generation to New England.

Small modular reactors (SMRs), which would be centrally produced in a factory, rather than custom built on site, may provide lower cost solutions in the future. "Techno-economic analysis of advanced small modular nuclear reactors"[172] provides a detailed analysis of the economics of this nascent technology.

Modeling assumptions used in this study for new nuclear capacity are detailed in Annual Decarbonization Perspective 2023.[173]

B.1.e Biomass

As the most heavily forested state in the country, Maine has long utilized biomass for energy

[166] An Act Regarding the Procurement of Energy from Offshore Wind Resources, 35-A M.R.S.A §3404, sub-§2

[167] U.S. Energy Information Administration. "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)," September 19, 2023. https://www.eia.gov/electricity/data/eia860/.

[168] U.S. Energy Information Administration. "Electricity Data Browser—Net Generation for All Sectors." Accessed February 15, 2024.

[169] U.S. Energy Information Administration. "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)," September 19, 2023. https://www.eia.gov/electricity/data/eia860/.

[170] Clifford, Catherine. "America's First New Nuclear Reactor in Nearly Seven Years Starts Operations.".

[171] Eash-Gates, Klemun, Kavlak, McNerney, Buongiorno, Trancik, "Sources of Cost Overrun in Nuclear Power Plant Construction Call for a New Approach to Engineering Design," Joule (4)2348–2373, 2020.

[172] Asuega, Anthony, Braden J. Limb, and Jason C. Quinn. "Techno-Economic Analysis of Advanced Small Modular Nuclear Reactors." *Applied Energy* 334 (March 15, 2023): 120669. https://doi.org/10.1016/j.apenergy.2023.120669.

[173] EER. "Annual Decarbonization Perspective 2023.".

production.[174] In 2022, biomass was used to produce 14% of Maine's electricity,[175] largely in combined heat and power (CHP) systems installed at industrial facilities. These facilities are able to produce a steady supply of both heat and electricity that is used to power industrial operations, including for production of paper and wood products.

Maine also has several stand-alone biomass electric generation facilities that are not part of a CHP system, as well as a number of electric generators that use landfill gas or municipal solid waste to produce electricity. These have a total capacity of just under 200 MW.[176]

B.1.f Thermal Electricity Generation

Four broad classes of technology represent the majority of thermal generation capacity in the United States. The first class is steam generators, which burn coal or natural gas to boil water into steam, which powers a steam turbine to produce electricity.[177] Maine has just 80 MW of natural gas-powered steam capacity and currently has no coal-powered steam plants. Across New England, 1,170 MW of conventional steam generation remains. New steam turbines are seldom being developed, as the technology has largely been displaced by the next two thermal generation classes.

In recent years, combustion turbines, which burn fuel inside a spinning turbine to produce electricity, have grown in popularity. Combustion turbines, which are based on the same engineering principles as aircraft engines, are modular and mass-produced, making them cheaper and easier to deploy than traditional steam plants. Additionally, combustion turbines can cycle their output up and down much better than steam plants, which means that they are capable of quickly adjusting energy production in response to changes in supply or demand. At the beginning of 2023, Maine had 354 MW of natural gas combustion turbine capacity, with another 1,560 MW operating throughout New England.[178]

Some power plants combine the previous two technologies. These plants use combustion turbines to produce electricity, then use the exhausted gases to boil water into steam, which is run through an auxiliary steam turbine. These "combined cycle" gas turbines can reach the highest efficiencies of any thermal plants, as much as 50%,[179] but also have higher capital cost than basic gas turbines. At the beginning of 2023, Maine had 1.4 GW of natural gas combined cycle turbine capacity, with another 15 GW operating throughout New England.[180]

A fourth class of thermal capacity, internal combustion engines, represent a relatively small share of electricity generation but provide reliability value. These engines operate just like the engine in

[174] U.S. Energy Information Administration. "Maine Profile Analysis," October 19, 2023. https://www.eia.gov/state/analysis.php?sid=ME#17.

[175] U.S. Energy Information Administration. "Electricity Data Browser - Net Generation for All Sectors." Accessed February 15, 2024.

[176] U.S. Energy Information Administration. "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)," September 19, 2023. https://www.eia.gov/electricity/data/eia860/.

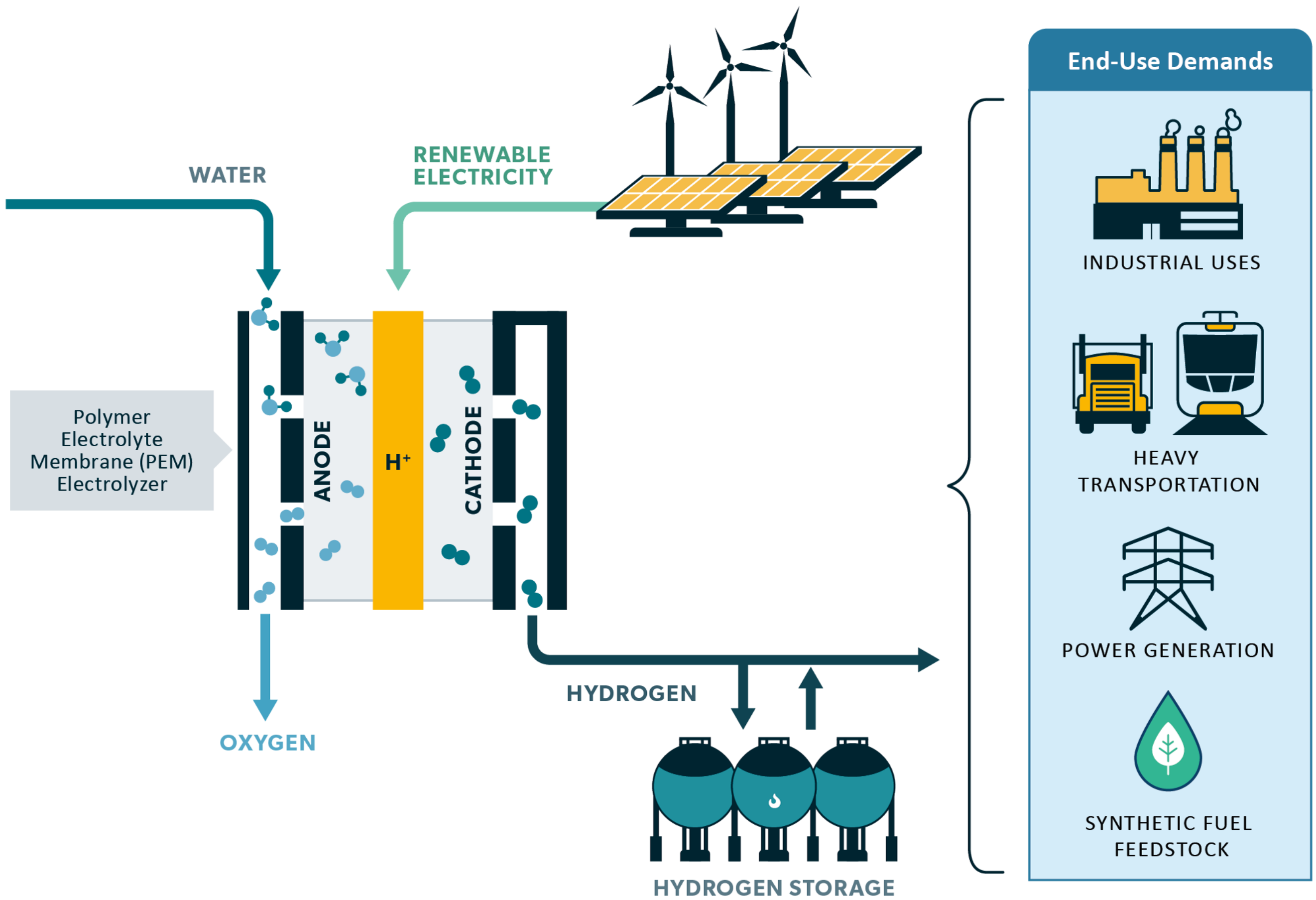
[177] The same steam technology is used for nuclear plants, the only difference being that nuclear plants use nuclear fuel as the heat source rather than coal or gas.

[178] U.S. Energy Information Administration. "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)," September 19, 2023.

[179] U.S. Energy Information Administration (EIA). "Use of Natural Gas-Fired Generation Differs in the United States by Technology and Region." Accessed March 11, 2024. https://www.eia.gov/todayinenergy/detail.php?id=61444.

[180] Ibid.

FIGURE B-1: RELIABILITY FRAMEWORK IN HIGH RENEWABLE SYSTEMS



Source: [Massachusetts Clean Energy and Climate Plan for 2050], December 2022.

cars, but instead of turning wheels to move the car forward, they turn an electric generator. These are the smallest, cheapest, and most modular of thermal generation facilities, and can easily be installed a where they are needed, including on customer premises. They are frequently used as part of cogeneration setups, where the radiator fluid from the engine is passed through a heat exchanger that is used to heat domestic hot water.

With the exception of traditional steam power plants, all of these thermal generators can easily ramp production up and down, so they could be used to supplement production from variable renewables.

B.1.g Carbon-Neutral Fuels

While thermal electricity generation has historically been responsible for the electricity sector's share of carbon emissions, much of the existing capacity could be repurposed to burn carbon-neutral fuels, such as biofuels, hydrogen, and synthetic hydrocarbons [181] made from captured carbon dioxide. As an example, Figure B-1 illustrates the production pathway for hydrogen using renewable electricity as well as the end-uses. Synthetic hydrocarbon fuels can be produced by combining hydrogen with CO2 (or CO). The CO2 can come from remaining emitting sources

[181] Hydrocarbons are fuels built around chains of carbon molecules. Common examples are natural gas (methane), propane, and gasoline.

like power plants or industries, from direct air capture, or from biomass processes.

The supply of biofuels is limited, and synthetic fuels are currently more expensive than fossil fuels, but prices are likely to decrease as technology improves and production increases over the coming decades.[182]

Many of these carbon-neutral fuels could serve as drop-in substitutes for difficult-to-electrify parts of the transportation industry (including aviation, shipping, and some heavy trucking) and as energy sources for space and water heating in homes and businesses. Carbon-neutral versions of all common gaseous and liquid fuels can be produced using biological and/or chemical processes.

This study does not focus on engineered sequestration (i.e., carbon capture and storage), as Maine (and much of the Northeast) does not have a geology that would allow for captured carbon to be stored underground.

B.1.h Energy Storage

Large lithium-ion batteries can be paired with solar generation, charging, and discharging on a daily cycle. Long duration storage batteries have lower round-trip efficiencies than lithium-ion batteries, but may be less expensive to produce in the long run as they are manufactured from more abundant materials. Thermal energy storage can be deployed in industrial applications, where large masses of insulated bricks are heated with excess renewable energy, then "discharged" as heat to run high heat processes. Other forms of thermal energy storage can be deployed in some residential and commercial applications, where water or ice is pre-conditioned and then used to heat or cool a building as needed.

B.1.i Transmission and Distribution

Electric transmission is essential to helping Maine reach its greenhouse gas reduction targets. New transmission is crucial several parts of the energy transition, including:

- Connecting new renewables in new locations to existing load centers such as cities and towns
- Moving the additional electricity required to power newly electrified loads
- Reinforcing the connections between Maine and Eastern Canada, which can provide an abundant supply of flexible hydropower. As discussed above, hydropower is valuable for balancing output from variable renewables.

Building out additional transmission capacity is far from trivial. While some new transmission capacity can be built along existing rights-of-way by upgrading power lines, other transmission projects will require new siting.

Increased demand from electrification of heating and transportation will also increase local distribution system peaks, necessitating substantial reinforcement of the distribution system. The distribution system is approximately 30x longer than the transmission system at 5.5 million miles across the United States.[183]

B.2 Demand-Side Technologies

Direct combustion of fuels, predominantly for transportation and heating, is a source of GHG emissions. In order to decarbonize these end uses, it

[182] For a more detailed discussion of carbon-neutral fuels, see Dean Murphy and Weiss, Jurgen, "Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050," n.d. and Kwok, Gabe, "Low Carbon Fuels in Net-Zero Energy Systems," August 2022.

[183] Climate, Jennifer Weeks, The Daily. "U.S. Electrical Grid Undergoes Massive Transition to Connect to Renewables." Scientific American. Accessed March 18, 2024. https://www.scientificamerican.com/article/what-is-the-smart-grid/.

is necessary to either serve them with electricity produced by clean generation or directly with low/no carbon fuels. A number of alternative end-use technologies have emerged in recent years to ease the transition away from fossil fuels, including electric vehicles, heat pumps for space and water heating, and induction stoves. Additionally, demand-side flexibility can smooth the transition to a decarbonized energy system by shifting load (particularly EV charging load) and make it more adaptable to the intermittent output of renewables.

B.2.a Space Heating Electrification

Space heating is the single largest energy end use in homes in Maine, representing 56% of residential energy consumption.[184] Unlike much of the U.S., which gets most of its space heating energy from natural gas, 56% of space heating energy in Maine comes from heating oil and 14% from propane (Figure 10)—which release more emissions per-unit of heating energy than natural gas.

While a switch from delivered fuels to natural gas would result in modest greenhouse gas emissions reductions in the near-term, the potential savings are limited to about 30% due to the modest difference in emission factors.[185] On the other hand, electrifying space heating could result in much steeper emissions reductions if it is powered by a low-carbon electricity supply.

In recent years, air source heat pumps have emerged as a powerful tool for decarbonizing the space heating sector. Like air conditioners and refrigerators, heat pumps use a vapor-compression process to move heat from a cool environment to a warm environment. Modern heat pumps can achieve an average coefficient of performance (COP) of three or more, meaning that for every unit of electric energy that the heat pump consumes, it transfers three units of heat energy into the conditioned space. Maine recently surpassed its goal of installing 100,000 heat pumps in the state by 2025 and has raised the new target of installing 175,000 additional heat pumps by 2027.[186]

While air source heat pumps have historically struggled to provide adequate heating capacity when the outdoor temperature drops below freezing, modern cold climate air source heat pumps (ccASHPs) are now required to report their maximum capacity when the ambient temperature is 5F and retain a COP of at least 1.75[187] at that temperature.

Air source heat pumps could be used either to supplement heating from fossil fuel systems or replace these systems altogether. When configured as stand-alone systems, the study estimates that the average equipment cost of a whole-house heat pump

[184] U.S. Energy Information Administration. "2020 Residential Energy Consumption Survey (RECS)." Accessed December 6, 2023. https://www.eia.gov/consumption/residential/data/2020/.

[185] Moreover, access to natural gas distribution infrastructure is extremely limited in Maine, so few customers are even eligible to make this switch.

[186] Efficiency Maine Trust (EMT) counts heat pumps by "heat pump equivalents" (HPe) where 1 HPe = 25.1 MMBTU/ year modelled offset. This is equivalent to EMT's Tier 1 residential first units, but not directly equivalent to the total number of rebates or physical heat pumps. EMT tracks their rebates this way to compare large VRF systems (>1 heat pump equivalent) and smaller packaged terminal heat pumps (<1 heat pump equivalent) accurately. State of Maine Priority Climate Action Plan. March 1, 2024. https://www.maine.gov/future/sites/maine.gov.future/files/2024-01/PCAP-Template-MAINE%20-%201_9_24.pdf.

[187] Northeast Energy Efficiency Partnerships (NEEP). "Cold Climate Air Source Heat Pump Specification (Version 4.0)," January 1, 2023. https://neep.org/sites/default/files/media-files/cold_climate_air_source_heat_pump_specification_-_version_4.0_final.pdf. This standard applies to central heat pumps. The standards are slightly relaxed for variable refrigerant systems and packaged terminal heat pumps.

in an existing home in Maine is $10,200, with installation costing an additional $1,500. Equipment costs are expected to fall by approximately 25% by 2050 due to technology improvements, while installation costs remain relatively constant.[188] Conventional fuel-burning heating systems are considerably cheaper, with equipment costs ranging from under $1,000 to $2,500 and installation costs covering a similar range. Hybrid heating systems, which combine heat pumps with backup fossil fuel heating, have lower equipment costs than whole-house heat pump systems (due to their lower-capacity heat pumps) but higher installation costs (due to the added complexity of connecting multiple heating systems together).

Another option for heating electrification is ground-source heat pumps (GSHPs). These systems have higher efficiencies than air-source heat pumps because they draw thermal energy from the ground, which is warmer in the winter than the ambient air. However, they are also significantly more costly to install, as drilling or excavation is required to install the ground heat exchanger.

B.2.b Water Heating Electrification

Domestic hot water represents another 16% of residential end use energy consumption in Maine.[189] Like space heating, the majority of energy for domestic hot water comes from delivered fuels. Electric resistance water heaters and heat pump water heaters both offer opportunities to decarbonize this major end use. Electric resistance water heaters convert electricity to heat using an electric resistance coil, much like the coil in a toaster oven or electric stove. Heat pump water heaters operate like heat pump space heaters, except instead of pulling heat from the outdoor air, they pull heat from the room in which they are installed (typically a basement). Heat pump water heaters are significantly more efficient than electric resistance heaters (COPs are between 3 and 3.5), but have higher upfront costs.[190]

B.2.c Transportation Electrification

The transportation sector is responsible for 49% of GHG emissions from fossil fuel combustion in Maine.[191] Total emissions from transportation have remained relatively constant over the last thirty years, with improvements in engine efficiency largely offset by greater demand for travel, and a shift from light-duty cars to larger SUVs and trucks.[192] As of 2022, 90% of energy consumed in the transportation is from petroleum.[193] To eliminate GHGs from the transportation sector, it will be necessary to either

[188] The U.S. Energy Information Administration (EIA). "Updated Buildings Sector Appliance and Equipment Costs and Efficiencies," March 2023. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/full.pdf. State-adjusted. Cost decline based on NREL EFS.

[189] U.S. Energy Information Administration. "2020 Residential Energy Consumption Survey (RECS)." Accessed December 6, 2023. https://www.eia.gov/consumption/residential/data/2020/.

[190] Rebate programs, such as Efficiency Maine, offer incentives that can bring the price of a heat pump water heater down to levels that are competitive with alternatives.

[191] Bureau of Air Quality Maine Department of Environmental Protection. "Ninth Biennial Report on Progress Toward Greenhouse Gas Reduction Goals," July 2022.

[192] From 1990 to 2004, light-duty trucks grew from 29.6% to 48.0% of new vehicle sales nationally. U.S. Environmental Protection Agency (EPA). "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021," EPA 430-R-23-002, 2023.

[193] U.S. Energy Information Administration (EIA). "Use of Energy for Transportation," August 16, 2023.

shift to electric vehicles or power internal combustion engine vehicles with low/no-carbon fuels.

In recent years, the selection of hybrid, plug-in hybrid, and fully electric cars and trucks have expanded. In 2010, there were only two fully electric car models available in the United States;[194] by the end of 2023, there were over 40 different EV models available in the United States, including a number of long-range SUVs and trucks suitable for Maine's climate and landscape.[195] Over the same period, EVs have grown from just 2.2% of new car sales to 11.3% of sales in the United States (and from 2.3% to 14.0% in New England).[196,197]

The price of new EVs have fallen over the last ten years due to improvements in manufacturing efficiency and are expected to continue to decline over the next decade, reaching parity with traditional ICE vehicles by around 2030.[198] EVs are also cheaper to operate and maintain than ICE vehicles.[199]

B.2.d Load Flexibility

The electric power system has always relied to some extent on customer load flexibility to manage peak loads. Historically, load flexibility was predominantly dispatched as part of demand-response programs, wherein customers were compensated for reducing load on the highest demand days of the year (typically in the middle of summer).

With greater adoption of dispatchable customer-located loads, including electric vehicles and distributed batteries, there has been growing potential for utilizing aggregations of these devices as virtual power plants (VPPs).[200] While space heating and cooling loads are typically only capable of curtailing load or shifting it a few hours to pre-heat or pre-cool, the charging profiles of electric vehicles and distributed batteries can be shaped throughout the day based on when energy is generated. This creates the opportunity to use aggregations of distributed resources to provide an array of grid services that have historically been supplied only by thermal power plants.

B.2.e Energy Efficiency

Maine has long regarded energy efficiency as an important tool for managing GHG emissions. In 2020, the American Council for an Energy Efficient Economy recognized Maine for being in the top one-third of states for energy efficiency policies and efforts. These are managed predominantly through Efficiency Maine Trust (EMT) and the Maine State Housing Authority (MaineHousing).[201]

---

194 Car and Driver. "Most Influential Electric Vehicles: An Illustrated History.

195 CNET. "Every EV Available in 2024, Ranked by Range." Accessed January 18, 2024.

196 Sales percentages are calculated based on AEO 2014 and AEO 2023, Table: Light-Duty Vehicle Sales by Technology Type.

197 A number of OEMs have recently announced that they would begin producing only electric vehicles: Mazda committed to a full-scale rollout of EV models between 2028 and 2030, Mercedes and Volvo planned to go electric by 2030, General Motors pledged to go 100 percent electric by 2035, and Honda and Acura also announced its goal to go fully electric by 2040.

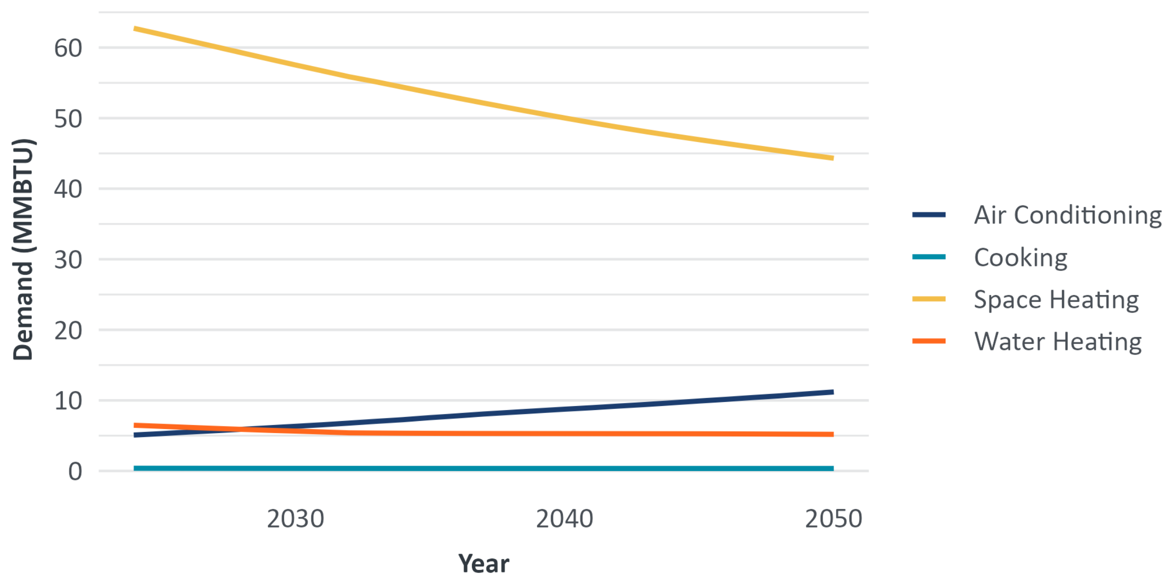
198 This estimate was developed by EER using a combination of sources from Annual Energy Outlook, Bloomberg New Energy Finance, and International Council on Clean Transportation

199 Harto, Chris. "Electric Vehicle Ownership Costs: Today's Electric Vehicles Offer Big Savings for Consumers," *Consumer Reports*. October 2020.

200 Hledik, Ryan. "Real Reliability-The Value of Virtual Power," Vol 1: Summary Report, May 2023.

201 State Of Maine Office Of The Governor. "2022 Maine Energy Summary and Assessment," March 15, 2022. https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/GEO_EnergyAssessment_2022_FINAL.pdf.

FIGURE B-2: PROJECTED ENERGY DEMAND FOR SEVERAL END USES IN AN AVERAGE MAINE HOUSEHOLD



Improved energy efficiency by itself cannot achieve the level of GHG reduction needed to reach Maine's goals, though it can reduce emissions to make progress toward those goals. More importantly, it can serve as an enabling technology that makes it easier to adopt other solutions. For instance, a more efficient building shell can facilitate electrification (it can be challenging for a heat pump to keep a drafty, poorly insulated building comfortable). It can also reduce the size and cost of the heat pump system required to electrify the building. Using energy more efficiently means that less primary energy is required, which means less infrastructure is needed to produce renewable electricity, clean fuels, and the intermediate infrastructure (energy storage, transmission, and distribution systems, etc.) that is required to deliver it to end users. Given the overall magnitude of Maine's clean energy needs, efficiency improvements can make it easier to achieve them, sooner, and ultimately at lower cost to customers.

Figure B-2 shows the projected energy demand of several major end use categories for an average household in Maine. Over the study period, primary demand of space heating energy falls by approximately 30% due to envelope efficiency improvements. Over the same interval, air conditioning demand more than doubles as more customers cool their spaces with air conditioners and heat pumps.[202]

B.2.f Industrial Technologies

A number of technologies have emerged in recent years that may help economically decarbonize some industrial end uses that currently rely on fossil fuels to produce heat. These include:

- **Hybrid boilers**. These operate on electricity when there is an abundance of renewable generation, and on backup hydrogen when electricity is scarce and prices rise.[203]

[202] Note that this figure represents an average across the state; space heating demand in any individual home would vary depending on if and when the homeowner invests in envelope improvements.

[203] Haley, B., R.A. Jones, J. H. Williams, G. Kwok, et al. *Annual Decarbonization Perspective: Carbon Neutral Pathways for the United States 2022*. Evolved Energy Research, 2022.

- **Heat pumps**. These can produce high-grade heat using electricity and either ambient air or low-grade waste heat as a heat source. High-efficiency industrial heat pumps currently have a high capital cost, but prices have been coming down.[204]

- **Thermal storage**. Thermal "batteries," typically made of bricks with electric resistance coils inside of them, are charged with electric resistance heating when there is an abundance of renewables and prices are low. They are then discharged as-needed when electricity prices are high. Thermal storage is significantly less expensive than battery electric storage, but also loses heat over time and so is best utilized on a diurnal cycle (e.g., charging every day at noon on excess solar and discharging throughout the afternoon).[205,206]

---

204 Ibid.

205 Ibid.

206 Spees, Kathleen. "Thermal Batteries-Opportunities to Accelerate Decarbonization of Industrial Heat.

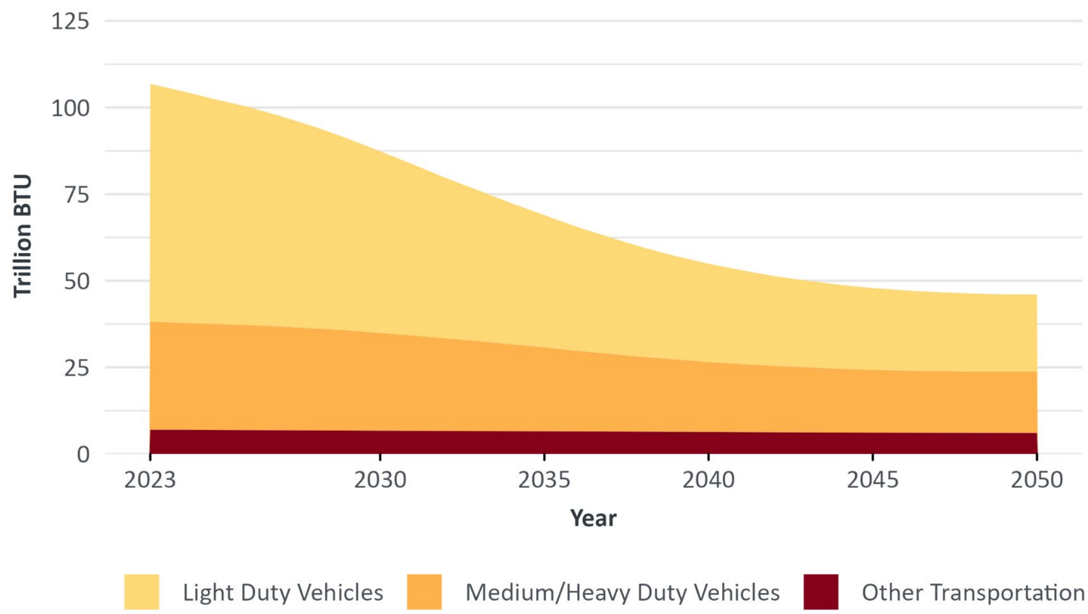
Appendix C: Detailed Forecast of Demand by Sector

C.1 Transportation

Within the transportation sector as a whole, on-road transportation (light, medium, and heavy-duty vehicles) represents the largest energy use with 93% of the total today (Figure C-1). The "other transportation" category shown in the plot includes aviation, rail, and other miscellaneous uses, which continue to use fuels; however, represent a minor portion of the overall transportation energy use. As explained above, this fuel demand is increasingly met with clean fuels.

The adoption of EVs is the primary strategy for reducing emissions from most on-road vehicle types, as EVs have become increasingly cost-competitive with conventional counterparts and as charging infrastructure improves. Consistent with Maine's goals to electrify transportation, the Core pathway achieves 219,000 light-duty electric vehicles on the road by 2030.[207] This represents 19% of all light duty vehicles on the road in 2030, compared to 1% today. As of October 2023, there were approximately 12,000 battery electric and plug-in-hybrid vehicles registered in Maine, up from about 4,200 in 2020.[208] These goals combined with the economy-wide emissions

FIGURE C-1: ENERGY USE IN THE TRANSPORTATION SECTOR IN MAINE, BY MODE

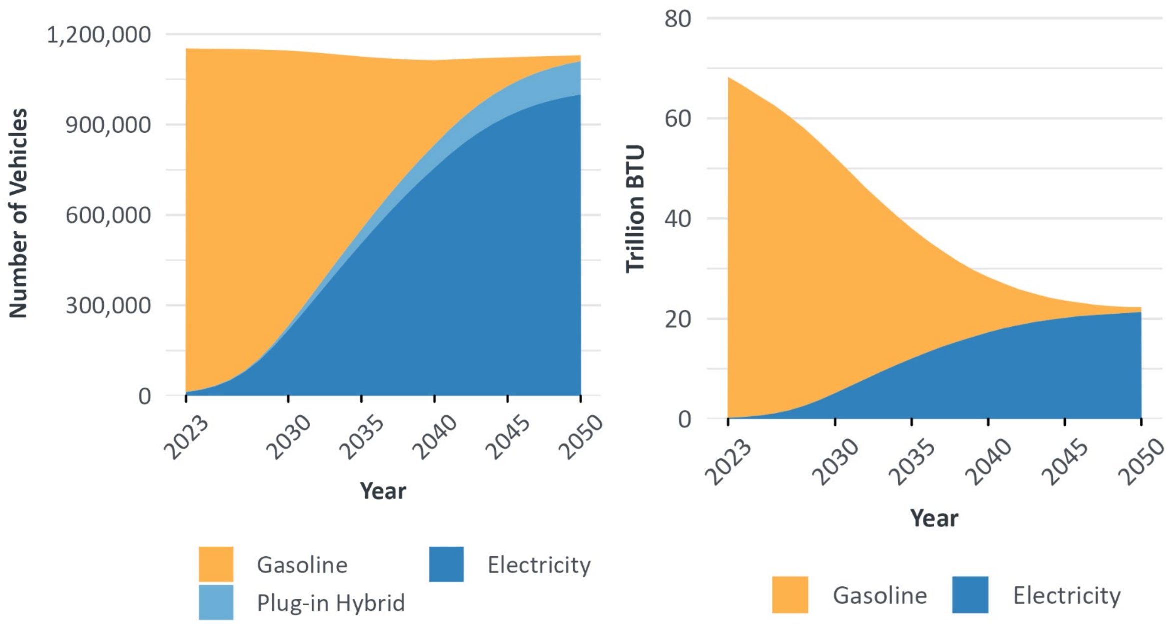


Note: "Other Transportation" includes rail and aviation.

[207] The Core Pathway and all other pathways share the same key assumptions regarding significant transportation electrification and assume Maine's transportation assumptions are met.

[208] Maine Climate Council Annual Report, *Maine Won't Wait*, December 2023.

FIGURE C-2: ENERGY USE IN THE TRANSPORTATION SECTOR IN MAINE, BY MODE

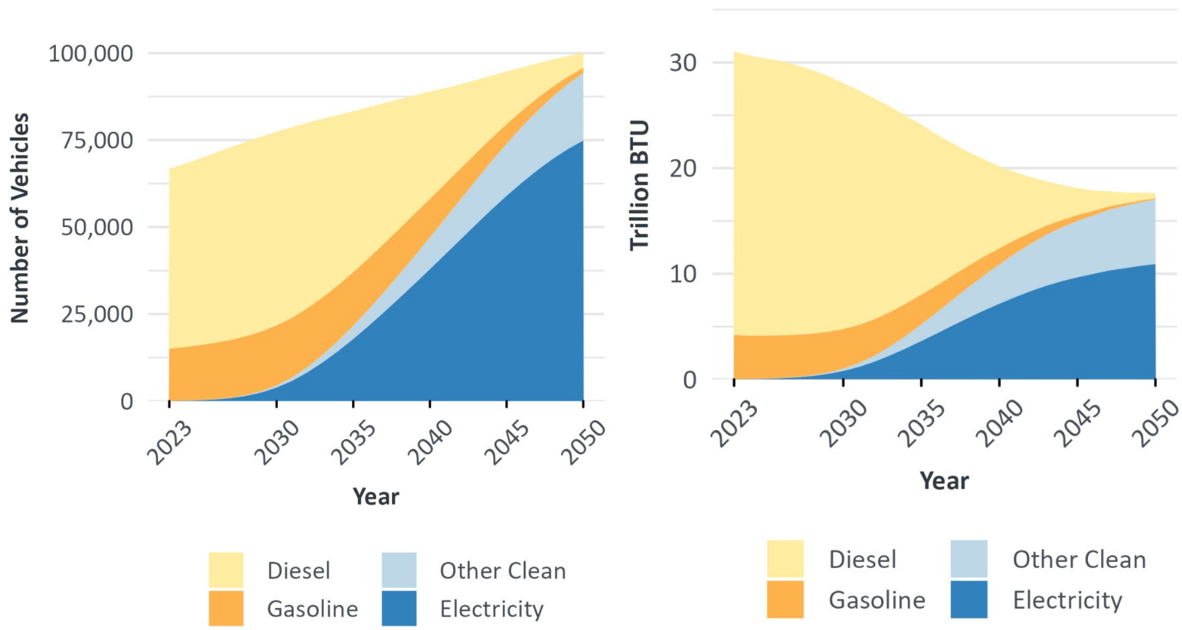


reduction targets lead to a transformation in Maine's transportation sector.

Figure C-2 shows the stock of light-duty vehicles on the road in Maine, and the resulting gasoline and electricity demand. There is a steady transition, picking up later this decade, from conventional ICE vehicles that use gasoline or diesel to electric and plug-in-hybrid electric as vehicles reach the end of their useful life. The market share of plug-in-hybrid electric vehicles, which typically operate both an electric motor and conventional engine, grows slightly. As of 2040, 68% of light-duty vehicles on the road are battery electric vehicles, 7% are plug-in hybrid, and 25% use conventional fuel. By 2050, almost all light-duty vehicles on the road vehicles are battery electric or plug-in-hybrid electric vehicles. Total energy demand falls precipitously, due to the higher efficiency of EVs relative to ICEs (a standard ICE engine has a combustion efficiency of 10–30%, while electric motors convert more than 80% of the electrical energy to motion at the wheels). As a result, by 2040, gasoline consumption falls by 84%.

Non-light duty vehicles undergo a transition as well (Figure C-3), albeit a slower one. There is a diversity of vehicles with different use cases here (e.g., buses, delivery vans, box trucks, garbage trucks) and electrification solutions are less established for some of these use cases. The Core pathway projects that by 2040, 43% of non-light duty on-road vehicles (including medium-duty, heavy-duty, buses) are fully electric. In 2040, there is still a significant amount of fuel consumption, with clean fuels representing 18% of the energy use ("Other Clean" category shown in Figure 61). By 2040, 47% of medium and heavy-duty trucks, representing 46% of energy use for on-road transportation, continue to use diesel or gasoline rather than batteries. By 2050, the share of vehicles using diesel or gasoline decreases to 6%, representing 4% of the energy consumption in on-road transportation. The remaining 10% of the vehicles use clean fuels derived from a combination of liquid hydrogen and ammonia in 2040 and this percentage increases to 19% by 2050. Some limited fossil fuel use (diesel, gasoline, LPG) remains. The vehicles relying on fuels represent hard-to-electrify use cases that tend to consume more fuel per vehicle due to their heavier weight and tend to travel longer distances.

FIGURE C-3: ALL OTHER ON-ROAD VEHICLES IN MAINE: NUMBER OF VEHICLES (LEFT) AND ENERGY USE (RIGHT)



Note: There are a small number of vehicles currently on the road that use either compressed natural gas or propane. These are included in the transition modeling but not represented above. "Other Clean" includes liquid hydrogen.

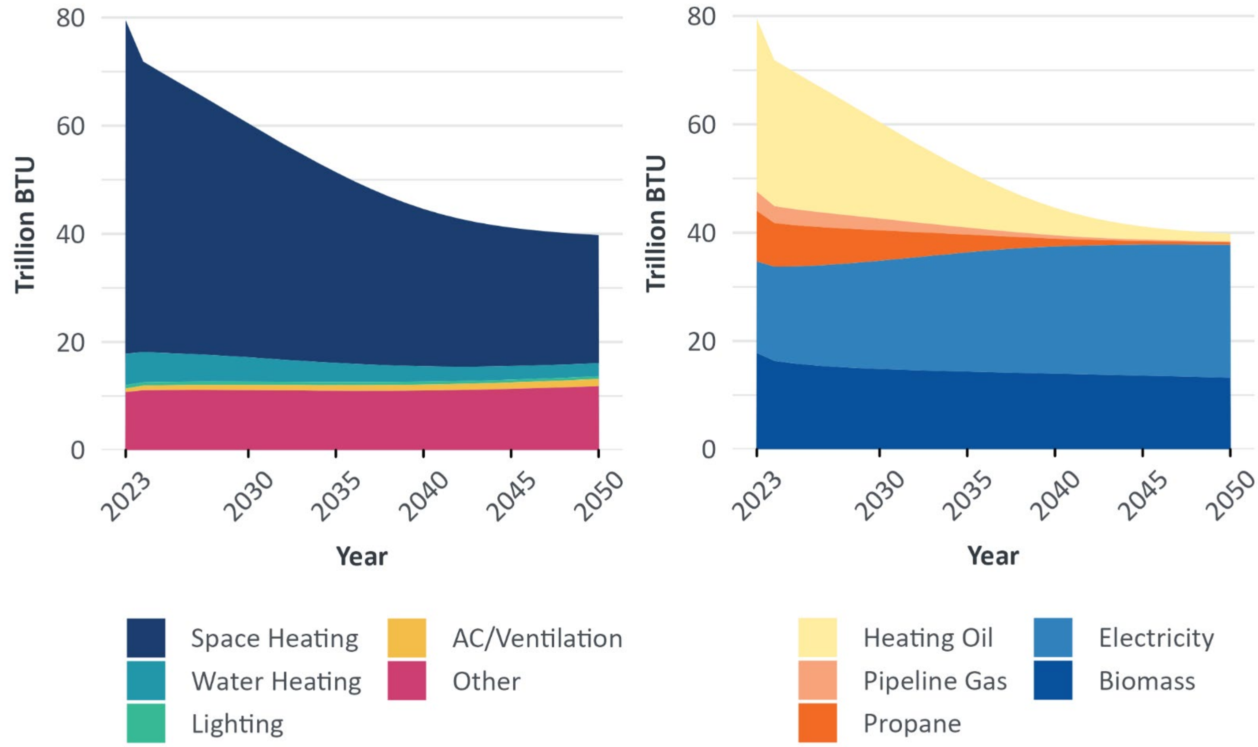
Besides increasing the total amount of electricity consumed, transportation electrification will have other implications for the grid. Increased EV charging will necessitate upgrading distribution and transmission infrastructure, especially in areas with higher EV adoption. However, taking advantage of the flexible nature of EV charging loads can prevent potential costly impacts and enable EV loads to help balance the grid. Several mechanisms exist to help unlock this flexibility such as implementing time-varying rates that encourage charging during periods of abundant and affordable electricity. Managed charging programs optimize charging times based on the grid's needs, and evolving "vehicle-to-grid" programs allow EV batteries to discharge electricity back to the grid when it is heavily stressed. The impact of varying degrees of load flexibility is examined in Section III.B.3 and policy considerations are discussed in further detail in Section IV.

C.2 Residential and Commercial Buildings

The Core pathway relies on a high electrification framework to decarbonize building heat, where rapid adoption of whole-home heat pumps results in a transition away from fuel-based heating systems in most homes.[209] As of 2023, Maine had surpassed its goal of installing 100,000 new heat pumps by 2025, representing significant progress in reducing the reliance on heating oil, and recently added a new target to install another 175,000 heat pumps by

[209] The same high electrification framework was used for the buildings sector in all other pathways except for the Hybrid Heat pathway.

FIGURE C-4: RESIDENTIAL BUILDING ENERGY USE IN MAINE



Notes: The "Other" category on the left includes clothes drying, clothes washing, computer use, cooking, dishwashing, freezing, furnace fans, refrigeration, televisions, and other uses.

2027.[210,211] Achieving this target would bring the total number of heat pumps in the state to about 320,000 by 2027. All pathways, including the Core pathway, are calibrated to achieve Maine's heat pump adoption targets. Currently, heat pumps make up 11% of the total heating equipment stock in the residential sector, and this is projected to increase to 54% in 2040 and 61% in 2050.

Space heating is the single largest energy end-use in homes (Figure C-4, left panel). Currently, 56% of homes in Maine burn heating oil for space heating, compared to the national average of 4%.[212] In total, heating oil represented about 40% of the residential sector energy use in 2023 (Figure C-4, right panel). In the Core pathway, most customers switch from furnaces and boilers to electric heat pumps as older equipment reaches the end of its life.[213] Collectively,

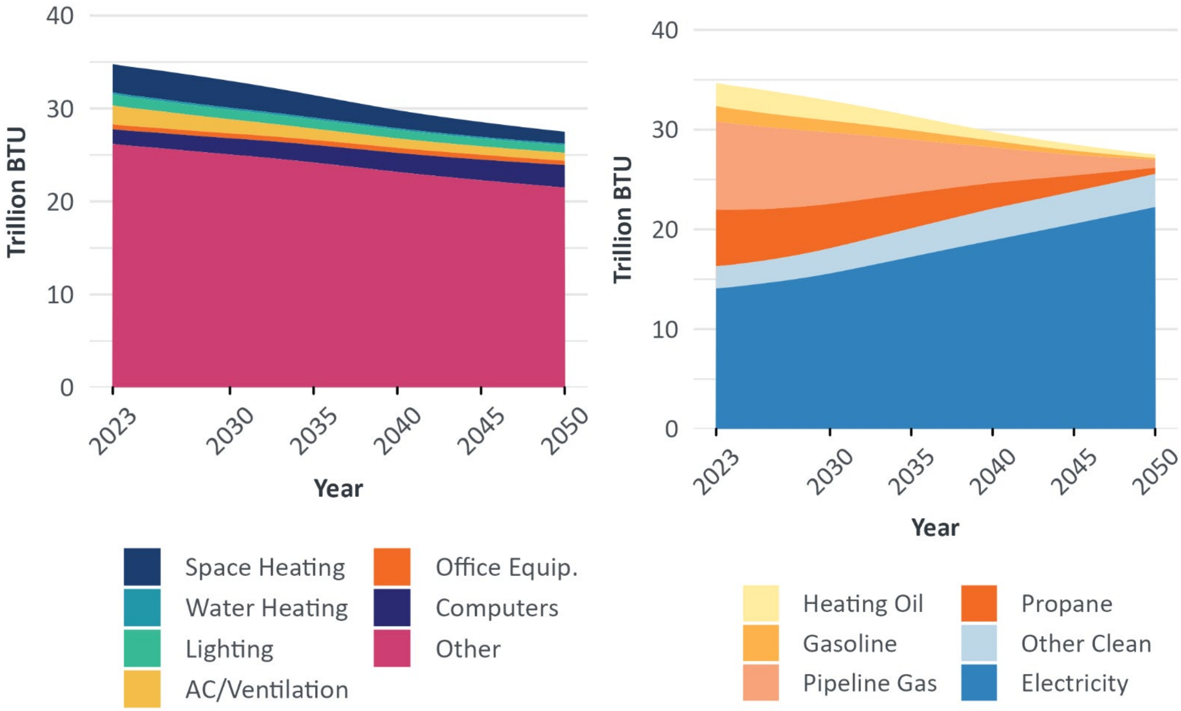
210 Office of Governor Janet T. Mills. "After Maine Surpasses 100,000 Heat Pump Goal Two Years Ahead of Schedule, Governor Mills Sets New, Ambitious Target".

211 Efficiency Maine counts heat pumps by "heat pump equivalents" (HPe) where 1 HPe = 25.1 MMBTU / year modelled offset. This is equivalent to EMT's Tier 1 residential first units, but not directly equivalent to EMT's total number of rebates or physical heat pumps. EMT tracks their rebates this way to compare large VRF systems (>1 heat pump equivalent) and smaller packaged terminal heat pumps (<1 heat pump equivalent) accurately.

212 Maine Climate Council Annual Report, *Maine Won't Wait*, December 2023.

213 The transition from direct combustion of fossil fuels in homes to heat pumps is a key driver of the decrease in primary energy consumption from space heating. Other measures, including replacing electric resistance heating with electric heat pumps and weatherizing building envelopes, also reduce energy demand.

FIGURE C-5: COMMERCIAL BUILDING ENERGY USE IN MAINE



Notes: The "Other" category on the left includes district services, refrigeration, cooking and other unspecified commercial uses. The "Other Clean" category on the right includes mainly steam.

872,000 heat pumps in Maine are projected to serve 21,887,905 MMBTU of space heating demand in 2040. [214] By 2040, fuel consumption in homes represents only 16% of the residential energy use; and by 2050, the share of fuel falls to 5% of residential energy use (without about half of this fuel blend coming from carbon-neutral sources).

Commercial buildings undergo a similar transition in energy use (Figure C-5). Electricity consumption increases as building end-uses are electrified. Unlike in homes, pipeline gas use currently makes up a significant portion (~30%) of commercial sector overall energy use. With electrification and the use of a limited amount of clean fuels involving steam and solar energy to meet the residual energy demand, fossil fuel consumption in commercial buildings falls to 26% by 2040 and 7% by 2050.

Building electrification requires significant capital investment in homes and businesses. The initial purchase and installation costs may represent a barrier to adoption, especially for low-income populations. Besides equipment purchases, adoption of new equipment may also require building upgrades, such as electric upgrades, duct installation, and efficiency improvements, depending on the building's age and condition. The long lifetimes of heating, ventilation, and air conditioning equipment (15–25 years on average) also contributes to a low turnover rate. It will be important to seize opportunities to replace fossil fuel-based systems with electric alternatives when existing equipment reaches the end of its operational life. The Key Policy Implications section delves deeper into the various policy mechanisms designed to address these adoption barriers.

[214] This estimate of the number of heat pumps is based on the HPe relationship described above.

C.3 Industry

Industrial energy use represents 16% of Maine's total final energy demand in 2023. The largest energy-consuming subsectors are construction and chemicals. In the Core pathway, the share of industrial energy use slightly increases over time due to the efficiency-induced reduction in final energy use in the residential, commercial, and transportation sectors, growing to 21% in 2040 and 23% in 2050. As Figure C-6 shows, industrial energy use is similarly transformed over time, though electrification opportunities are more limited in the near-term than in other sectors. One near-term emissions reduction solution for industry is energy efficiency (year over year efficiency gains of 1% per year); another is electrification of process heat and steam, and various equipment that now relies on petroleum. Electricity consumption increases from 23% of industrial energy use in 2023 to 36% in 2040. Electrified equipment can also more easily take advantage of more abundant clean energy to the extent that the loads are flexible. Some of the end-uses that currently rely on pipeline gas switch to hydrogen.

FIGURE C-6: FINAL DEMAND FOR FUELS AND ELECTRICITY IN INDUSTRY