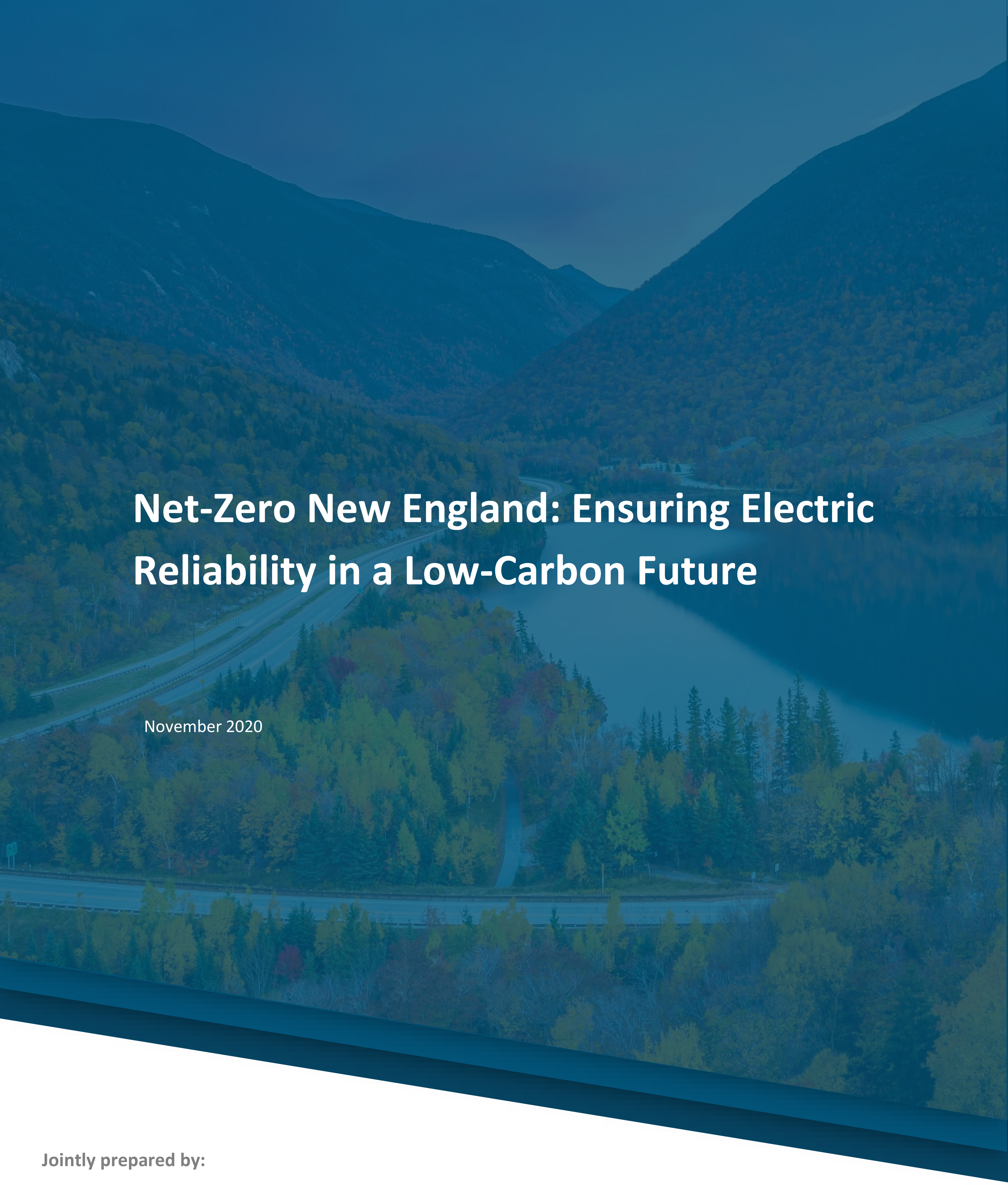

Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future

November 2020

Jointly prepared by:

Energy+Environmental Economics

ENERGY FUTURES INITIATIVE

Project Team

This report was produced in collaboration between E3 and EFI and sponsored by Calpine Corporation. While Calpine provided input and perspectives regarding the study scope and analysis, all decisions regarding the analysis were made by E3 and EFI. Thus, this report solely reflects the research, analysis, and conclusions of the E3 and EFI study authors.

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. E3's analysis is utilized by the utilities, regulators, developers, and advocates that are writing the script for the emerging clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Calgary, and Raleigh.

E3 Primary Authors: Elizabeth Mettetal, Sharad Bharadwaj, Manohar Mogadali, Saamrat Kasina, Clea Kolster, Vignesh Venugopal, Ben Carron, Ari Gold-Parker, Robbie Shaw, Zach Ming, Amber Mahone, and Arne Olson.

The Energy Futures Initiative, Inc. (EFI) is a nonprofit clean energy think tank dedicated to harnessing the power of innovation–both in technology and policy–to create clean energy jobs, grow economies, enhance national and global energy security, and address the imperatives of climate change. EFI was founded in Washington, DC by former Energy Secretary Ernest Moniz. The EFI team and its global network of experts provides policymakers, industry leaders, NGOs and other leaders with analytically based, unbiased policy options to advance a cleaner, safer, more affordable and more secure energy future. The majority of project funding is derived from charitable and educational nonprofit institutions. EFI maintains editorial independence from its public and private sponsors.

EFI Primary Authors: Alex Breckel, Alex Kizer, Sam Savitz, Anne Canavati, Richard Randall, and Tomas Green.

Advisory Group

The report authors greatly benefited from the advice and feedback of an Advisory Group comprising a diverse group of stakeholders with relevant expertise for this project and chaired by former energy secretary Ernest Moniz. Participation on the Advisory Group does not imply endorsement of any of the report's conclusions.

Sue Tierney, Analysis Group

Daniel Sosland, Acadia Center

Arnie Quinn, Vistra Energy

Roger Kranenburg, Eversource Energy

Chris Knittel, MIT Sloan School of Management

Barbara Kates-Garnick, Fletcher School, Tufts University

Sarah Jackson, The Nature Conservancy

Bill Fowler, Sigma Consultants, Inc.

Dan Dolan, New England Power Generators Association

Patricia DiOrio, National Grid
Armond Cohen, Clean Air Task Force
David Cash, UMass Boston

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Abbreviations

RPS	Renewable Portfolio Standard
TCI	Transportation Climate Initiative
EEPS	Energy Efficiency Portfolio Standard
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
SIT	EPA's State Inventory Tool
SEDS	EIA's State Energy Data System
IPCC	Intergovernmental Panel on Cimate Change
ISO-NE	Independent System Operator-New England
CELT	ISO-NE's annual Capacity, Energy, Loads and Transmission Report
NEG-ECP	New England Governors and Eastern Canadian Premiers
NEPOOL	New England Power Pool
NYSERDA	New York State Energy Research and Development Authority
FAA	Federal Aviation Administration
CLEEN	FAA's Continuous Lower Energy, Emissions and Noise Program
NREL	National Renewable Energy Laboratory
ReEDS	Regional Energy Deployment System, NREL-developed capacity planning model
SAM	NREL's System Advisor Model
NASEM	National Academies of Science, Engineering and Medicine
DOT	Department of Transportation
NEMS	EIA's National Energy Modeling System
RECS	EIA's Residential Energy Consumption Survey
CBECS	EIA's Commercial Buildings Energy Consumption Survey
AEO	EIA's Annual Energy Outlook
NEEP	Northeast Energy Efficiency Partnership
NOAA	National Oceanic and Atmospheric Administration
ARPA-E	Advanced Research Projects Agency - Energy
GHG	Greenhouse Gas
MMT CO_2e	Million Metric Tons of CO_2 equivalent
VMT	Vehicle Miles Travelled
ODS	Ozone Depleting Substance
GWP	Global Warming Potential
LOLP	Loss of Load Probability
LOLE	Loss of Load Expectation
PRM	Planning Reserve Margin
UCAP	Unforced Capacity
ELCC	Effective Load Carrying Capability
MTTR	Mean Time to Repair
FOF	Forced Outage Factor

IPPU	Industrial Processes and Product Use
CC/CCGT	Combined Cycle Gas Turbines
CT	Combustion Turbines
ST	Steam Turbines
ZEV	Zero Emission Vehicle
EV	Electric Vehicle
L/M/HDV	Light/Medium/Heavy Duty Vehicles
LED	Light Emitting Diode
CDR	Carbon Dioxide Removal
CCS	Carbon Capture and Storage
BECCS	Bio-Energy with Carbon Capture and Storage
DAC	Direact Air Capture
SMR	Steam Methane Reforming
NSMR	Nuclear Small Modular Reactors
AS/GSHP	Air-Source/Ground-Source Heat Pump
ccASHP	Cold Climate Air-Source Heat Pump
COP	Coefficient of Performance
BTM PV	Behind-the-Meter Solar Photovoltaic
NECEC	New England Clean Energy Connect
CAES	Compressed Air Energy Storage

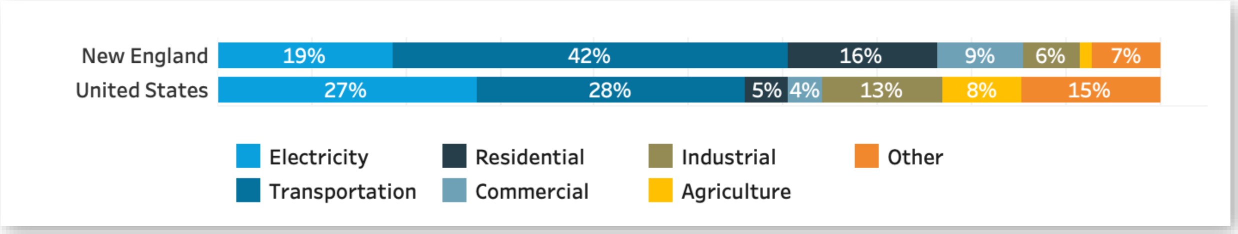
Executive Summary

The six New England states have adopted economy-wide greenhouse gas (GHG) reduction targets of at least 80% economy-wide emissions reductions by midcentury, with Massachusetts recently adopting a net-zero commitment. The electricity system will play a key role in achieving these targets through near-complete decarbonization of electricity supply and supporting the electrification of transportation, buildings, and industry. To date, there has been limited research on how the New England electricity system can reliably accommodate this dual challenge of growing electricity demand—increasingly characterized by peak winter heating demand—and reducing emissions to nearly zero. This study shows that cost-effectively meeting this dual challenge will involve the addition of large amounts of wind, solar, and battery storage resources, complemented by firm capacity to provide generation during extended periods of low wind and solar availability. Firm capacity includes natural gas power plants, nuclear, hydrogen generation, or other yet-to-be commercialized options such as long-duration storage. Achieving carbon goals with natural gas generation will require operating natural gas power plants at suitably low capacity factors, capturing their emissions, and/or utilizing low/zero-carbon fuels such as hydrogen.

E3 and EFI conducted this study to fill this research gap by evaluating net-zero economy-wide decarbonization pathways that meet New England's long-term goals while maintaining electric system reliability. Reliable electricity supplies are critical to the functioning of the modern economy and for the health and safety of people everywhere. This will increasingly be true in an electrified future in which New Englanders rely at least in part on electricity for heating and mobility on the coldest winter days. At the same time, decarbonizing the electricity system will require New England to deploy significant quantities of wind, solar, and energy storage resources. While these intermittent and/or energy-limited resources can make significant contributions to reliable electric system operations, numerous studies in other regions have demonstrated that complementary resources will continue to be needed to provide essential grid services and to generate electricity during extended periods of low wind and solar generation. This study assesses in detail the resources needed to maintain reliable electric service in a New England electricity system with high penetrations of renewable energy resources.

New England's GHG emissions in 2016 (the latest year with published estimates for all states) equaled 170 million metric tons of CO_2-equivalent (MMT CO_2e), roughly 3% of the U.S. total. Massachusetts accounts for roughly 44% of total New England emissions, primarily due to its larger population. Every state besides Vermont has seen gross emissions reductions since 1990, aided by the power sector transition from coal to natural gas. In 2017, all six New England states had lower per-capita energy consumption than the national average, with Rhode Island having the lowest in the country.[1] Figure ES-1 provides a comparison of 2016 emissions profiles for New England and the United States. Transportation is the largest source of carbon emissions in New England (42%) while electricity accounts for approximately 20%. New England will not be able to attain its GHG reduction goals with an exclusive focus on electricity production; it will be necessary to implement aggressive decarbonization on an economy-wide basis.

Figure ES-1. 2016 Greenhouse Gas Emissions Profile of New England and United States



Notes: Other includes waste, non-combustion, and industrial processes and product use (IPPU). Transportation, electrical generation, building heat, and industry account for nearly all of New England's emissions. Source: EIA, 2016; state emissions inventories, 2016.

New England's unique economy, resource availability, and geography will shape its path to decarbonization. The proportion of emissions attributable to transportation is higher than the national average, while the emissions from industrial sources are lower. Fossil fuel use for residential and commercial heat contributes a quarter of New England's emissions, and New England is the only region in the country where oil is the most common heating fuel. A successful clean energy transition will require sector-specific solutions that navigate a thicket of difficult issues related to planning, financing and siting of electricity transmission and other new energy infrastructure, while at the same time protecting environmentally-sensitive lands, preserving natural landscapes and alleviating the environmental burden on disadvantaged communities.

New England's electricity supply is already less carbon-intensive than much of the rest of the country. Natural gas fuels 40% of the region's electricity generation today, and its displacement of oil and coal over the past decades has contributed to halving power sector emissions since 2005. Nuclear generation is currently New England's largest source of carbon-free power, producing over seven times as much electricity as all the region's wind and solar combined. Prospectively, solar represents a relatively low-cost source of clean electricity in New England, despite capacity factors roughly half of those in the Southwestern United States. Solar can be complemented by high-quality offshore wind resources that are available in significant quantities, and New England states are already in the process of procuring significant amounts of offshore wind through long-term contracts. As prices fall, batteries also provide a useful complementary resource by shifting generation.

To map out plausible pathways toward economy-wide deep decarbonization in New England, E3 and EFI assess two "bookend" scenarios that achieve net-zero GHG emissions reductions by midcentury. The two scenarios are distinguished by their assumptions about the level of electrification in the building and transportation sectors as well as the availability of low-carbon fuels for transportation, buildings and industry. The results of this economy-wide analysis are used to develop corresponding electricity resource portfolios that meet New England's greenhouse gas and reliability needs, including new requirements imposed by electrification. Estimates of effective capacity needed to ensure resource adequacy are derived, as well as contributions toward those needs from renewable resources and batteries, across thousands of simulations based on 40 years of weather conditions. The computer modeling is complemented by a systematic assessment and prioritization of emerging innovations that could support the region's carbon neutral emissions goals and address the reliability challenge.

More specifically, this study evaluates a series of study questions in New England, including:

+ What decarbonization technologies and strategies are most likely to be successful in New England given its geography, weather, policy, economics, and other regional considerations?
+ How much must electricity sector emissions fall by 2050 to support economy-wide net-zero emissions goals?
+ How much additional electric load will materialize due to electrification of end-uses between now and 2050?
+ What is the cost-optimal electricity resource mix, subject to reasonable limitations on resource availability, to meet New England's energy and resource adequacy needs through 2050 while achieving economy-wide GHG goals?
+ What roles do various electricity supply resources play in achieving resource adequacy?
+ What are critical areas for innovation breakthroughs that can contribute to deep decarbonization and maintaining electric reliability?

Key Findings

The following key findings provide insight into how New England can provide affordable and reliable electric power under future scenarios that achieve net-zero economy-wide GHG emissions by 2050.

1. **Decarbonizing New England requires transformational change in all energy end-use sectors.** New England has long been an environmental policy leader, with progress in recent decades aided by the region's transition from oil and coal to natural gas. Today, direct energy use for transportation and buildings makes up two-thirds of the region's emissions. Key strategies for mitigating economy-wide greenhouse gas emissions are: (1) aggressive deployment of energy efficiency; (2) widespread electrification of end uses in the building, transportation and industrial sectors; (3) development of low-carbon fuels; and (4) deep decarbonization of electricity supplies.

2. **Electricity demand will increase significantly in New England over the next three decades under the net-zero scenarios studied.** In the two primary bookend scenarios, annual electricity demand grows by 70 to 110 Terawatt-hours (TWh), roughly 60 to 90% from today. Electric peak demand reaches 42 to 51 Gigawatts (GW) as the system shifts from summer to winter peaking in the 2030s. This demand growth is primarily due to electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. This large increase in electricity demand occurs despite significant energy efficiency included in the scenarios. Absent energy efficiency, demand growth would be even higher.

3. **Renewable electricity generation will play a major role in providing zero-carbon energy to the region.** The Base Case scenarios select a diverse mix of 47 to 64 GW of new renewable generation

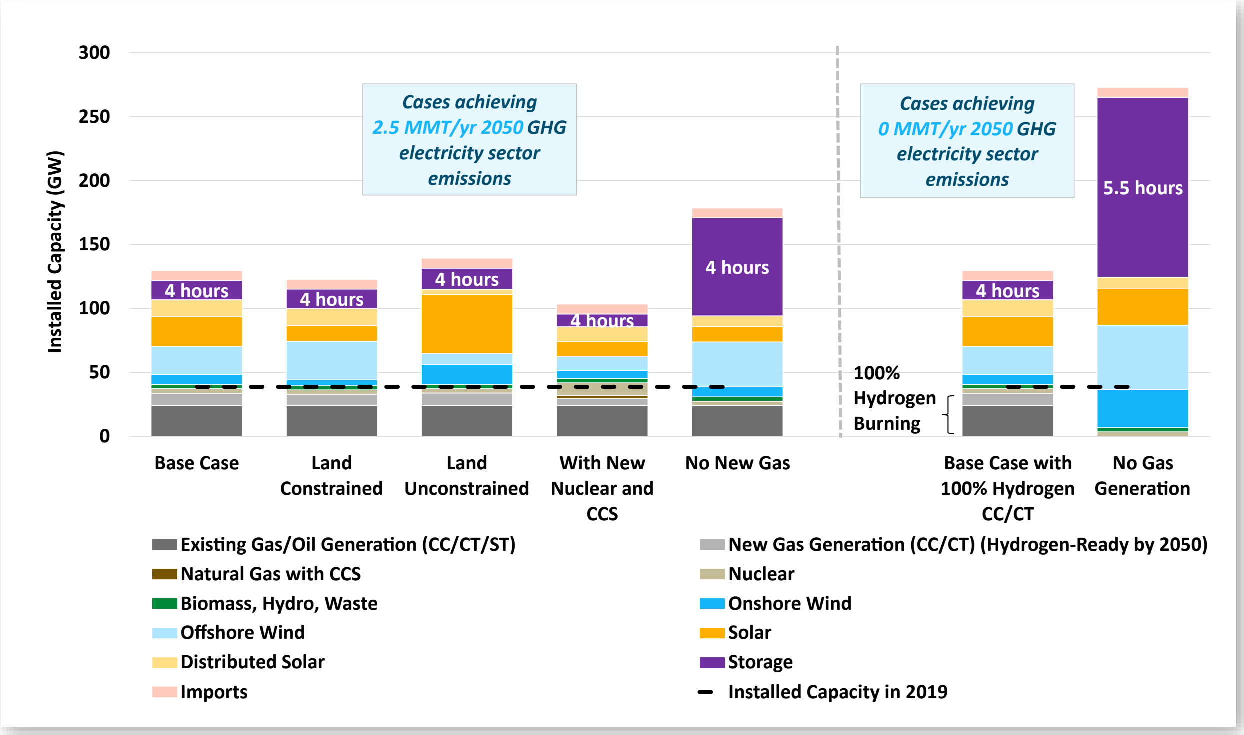
capacity by 2050, including land-based solar and wind, offshore wind, and distributed solar, along with 3.5 GW of incremental Canadian hydro. Renewable generation is needed to displace fossil fuel generation in the electricity system and to provide zero-carbon energy for vehicles, buildings and industry. Greenfield development will be required to reach adequate scale, even if opportunities to develop brownfield sites, rooftops, and marginal lands are maximized, notwithstanding the region's limited availability of land for renewable energy development. New England's constrained geography, slow pace of electric transmission planning, and historical difficulty siting new infrastructure are significant challenges that the region must overcome.

4. **A cost-effective, reliable, and decarbonized grid requires firm generating capacity.** Firm capacity is capacity that can provide electricity on demand and operate for as long as needed; today, natural gas and nuclear generation are the primary sources of firm capacity in the region. While today's renewable generation and battery storage technologies will play large roles in the future New England system, relying on these resources alone would require very large quantities of renewables and storage (Figure ES-2) and would be extremely costly (Figure ES-3). In practice, as much as 46 GW of firm capacity could be needed in 2050 to ensure resource adequacy; our Base Case includes about 34 GW of gas generation, 3.5 GW of nuclear, 8 GW of imports and 1 GW of biomass and waste (under High Electrification loads). Significant gas capacity is retained even though the gas plants operate far fewer hours and contribute less energy (and emissions) to the region than today. New resources may be developed and deployed in the future to provide low-carbon firm capacity such as advanced nuclear, natural gas plants with carbon capture and sequestration (CCS), long duration energy storage, or generation from carbon-neutral fuels such as hydrogen. These resources would require significant investments in supporting infrastructure; for example, natural gas with CCS or hydrogen would require dedicated pipeline infrastructure connecting New England to regions with suitable geology for carbon sequestration or hydrogen storage. Until one or more of these technologies is widely and commercially available, natural gas generation is the most cost-effective source of firm capacity, and some reliance on gas generation for resource adequacy is consistent with achieving a 95% carbon-free electricity grid in 2050 as long as the generation operates at a suitably low capacity factor.

5. **A broader range of technology choices lowers costs and technology risks.** The availability of low-carbon firm generation technologies – such as advanced nuclear or natural gas with CCS – could provide significant cost savings and reduce the pressure of renewable development on New England's lands and coastal waters. The 2050 incremental cost to achieve an electricity sector target of 2.5 million metric tonnes (MMT CO_2e) relative to a Reference Case (50% renewables) falls roughly in half when natural gas with CCS is made available, assuming technology cost declines are achieved. When advanced nuclear technology is also available at scale, the cost of decarbonization declines further (Figure ES-3). In addition to reducing direct costs, a portfolio approach for ensuring the availability of low-carbon firm generation resources mitigates the risks associated with the possibility that one or more technology options does not materialize as expected. Issues including uncertain innovation time horizons, difficulty building supporting infrastructure, incompatibility with other

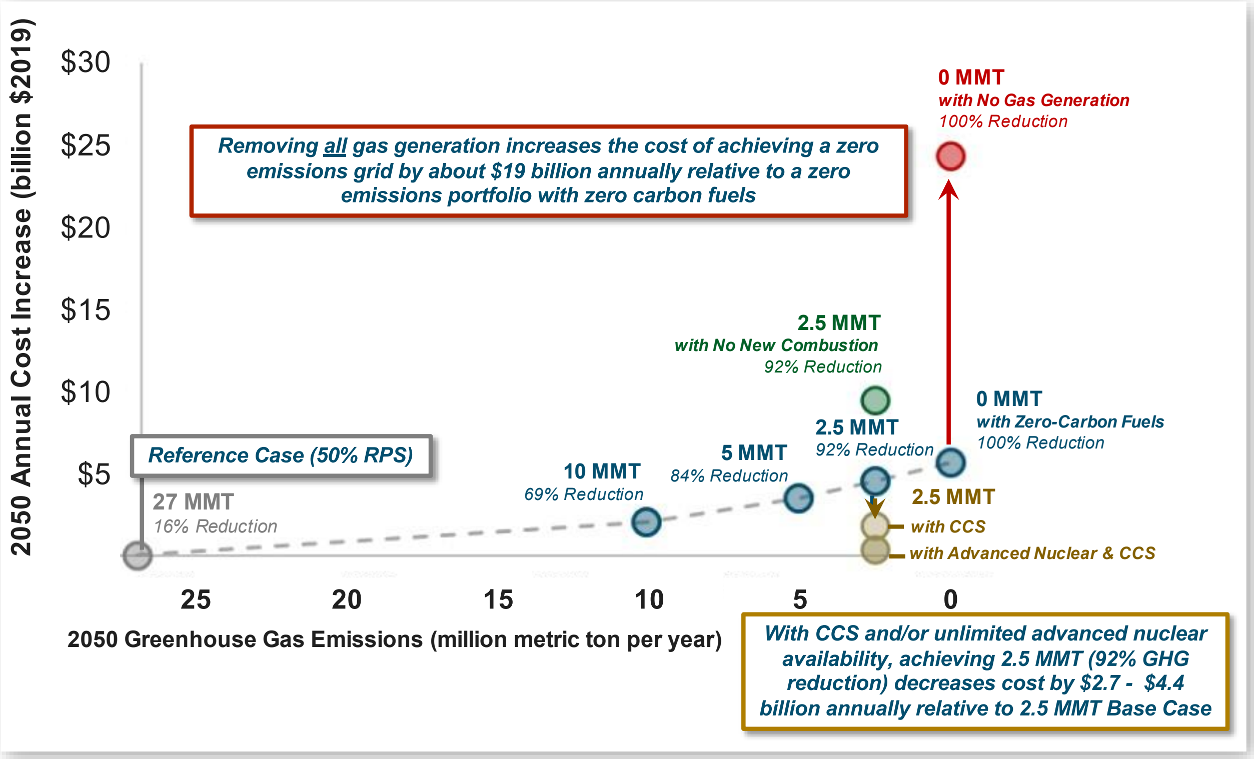
policy goals, or alignment with the decisions of neighboring regions may limit the role of some technologies in helping meet New England's climate goals.

Figure ES-2. Installed Capacity Across Base Case and Key Sensitivities in 2050 (High Electrification)



Notes: In the 0 MMT Base Case, all existing and new gas units, when dispatched, burn 100% hydrogen in 2050. In the 2.5 MMT model runs, hydrogen is available as a drop-in fuel and blended in at varying percentages with natural gas in order to meet the 2.5 MMT electricity sector target in 2050 only. The existing fossil capacity includes units burning natural gas, oil or coal today in combustion turbines (CT), combined cycles (CC) or steam turbines (ST), but only natural gas and hydrogen are burned by 2050. Our Base Case assumed modest land use constraints for renewable energy resources, nuclear capacity limited to about 3.5 GW, and hydrogen blending available when the model finds it economic to meet resource needs subject to constraints. New natural gas units can be equipped with Carbon Capture and Storage (CCS) in one of the sensitivities, but gas with CCS is not available in the Base Case. Annotations for storage represent average duration across the fleet.

Figure ES-3. Increase in Electricity System Modeled Costs Relative to Reference Case Across Selected Set of Scenarios in 2050 (High Electrification)



Notes: Cost increases are reported relative to the hypothetical Reference Case (50% RPS), which has annual costs in 2050 of $20.7 billion. Emissions reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States. The "No Gas Generation" Case removes all fossil and hydrogen/zero-carbon fuel generation (CC/CT/ST) from the portfolio.

6. **Achieving net-zero GHGs requires carbon dioxide removal (CDR), and New England's extensive stock of healthy forests and local forest management expertise provide an ideal local opportunity for CDR.** While CDR alone will not be enough to achieve economy-wide decarbonization or meet the region's policy targets, it supports achieving full carbon neutrality and potentially net-negative emissions in New England and beyond. The lack of suitable geology for carbon sequestration make direct air capture and bioenergy with carbon capture and storage poorly suited to the region, but a large stock of forests provides a good opportunity for in-region CDR. A more purposeful and explicit consideration of the carbon sequestration potential of New England's forests would help the region better manage tradeoffs between preserving forest land and new greenfield renewable energy development. Policymakers should consider incorporating practices that promote CDR across its forest lands, as well as other natural CDR options, which are the best candidates for near-term deployment.

7. **Achieving the commercialization of emerging technologies can be aided by leveraging regional innovation capacity.** New England's innovation ecosystem is one of the most robust in the world. Local policymakers can increase the likelihood of commercializing emerging technologies by orienting

the homegrown efforts of private, public, and academic researchers already developing science and business innovations relevant to decarbonization. Specifically, advanced nuclear, long-duration storage, and renewable fuels are innovation areas that have tremendous regional potential and could play a role in supporting a low-carbon power sector, especially when local innovation efforts are coordinated with federally-funded programs.

1 Introduction

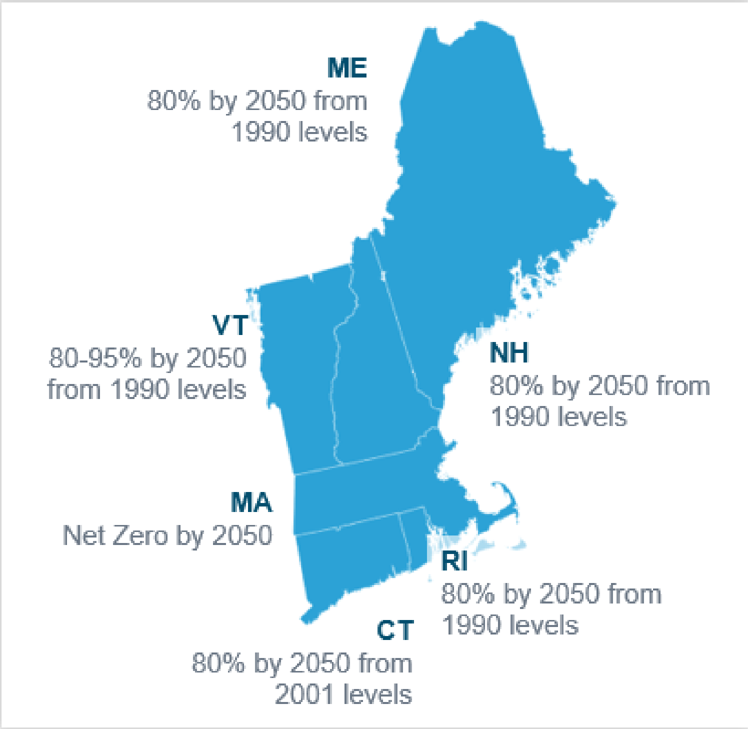
1.1 Study Motivation

The latest science, including the most recent IPCC Special Report, suggests that reaching net-zero emissions by mid-century will be necessary to slow the effects of climate change on ecosystems, economies, and human health. Recognizing the risks of climate change, the six New England states—Massachusetts, Connecticut, New Hampshire, Maine, Rhode Island, and Vermont—are pursuing a range of policies and actions to substantially reduce greenhouse gas (GHG) emissions across their economies by 2050 (Figure 1-1). Some key economy-wide policies include:[a]

- **Connecticut:** The Act Concerning Connecticut Global Warming Solutions requires the state to achieve an 80% reduction in emissions relative to 2001 levels by 2050.
- **Maine:** The state's Act to Promote Clean Energy Jobs and To Establish the Maine Climate Council creates a council that will lead Maine's efforts to reduce GHGs by at least 80% in 2050 (relative to 1990 levels). A subsequent executive order sets an economy-wide target of carbon neutrality by 2045.[2]
- **Massachusetts**: The Global Warming Solutions Act of 2008 requires the state to set a target of at least an 80% reduction in economy-wide emissions by 2050, relative to 1990 levels. In April 2020, the Secretary of Energy and Environmental Affairs signed a determination letter increasing the target to net-zero GHG emissions by 2050, including at least 85% direct emissions reductions.
- **New Hampshire:** The state's Climate Action Plan outlines a recommended goal of an 80% reduction in GHG emissions below 1990 levels by 2050.
- **Rhode Island:** The Resilient Rhode Island Act of 2014 set an economy-wide target of 80% GHG reductions relative to 1990 levels by 2050.
- **Vermont:** The state's Comprehensive Energy Plan establishes a goal of 80 to 95% GHG reduction below 1990 levels by 2050.

[a] The particular details of these policies and mandates vary by state, with not all states have binding economy-wide emissions reductions mandates.

Figure 1-1. State Economy-wide Greenhouse Gas Emissions Reduction Targets



Achieving these steep emissions reductions will require dramatic changes to the way energy is produced and consumed across the region. The electricity sector in particular will play a critical role in economy-wide decarbonization, enabling the electrification of transportation, buildings and industry. On the supply side, the electricity system will transition from one dominated by dispatchable resources to a system with a majority intermittent renewables (wind, solar), energy-limited (storage, demand response), and distributed technologies. The sector must also plan for new types of load, greater efficiency, and more flexible demand. This study focuses on how the electricity system can reliably meet growing load through this critical transition.

1.2 Goals of this Study

This study evaluates optimal resource mixes to achieve deep decarbonization goals consistent with a net-zero future for New England, while maintaining reliable electricity service. To this end, the study investigated the following key questions:

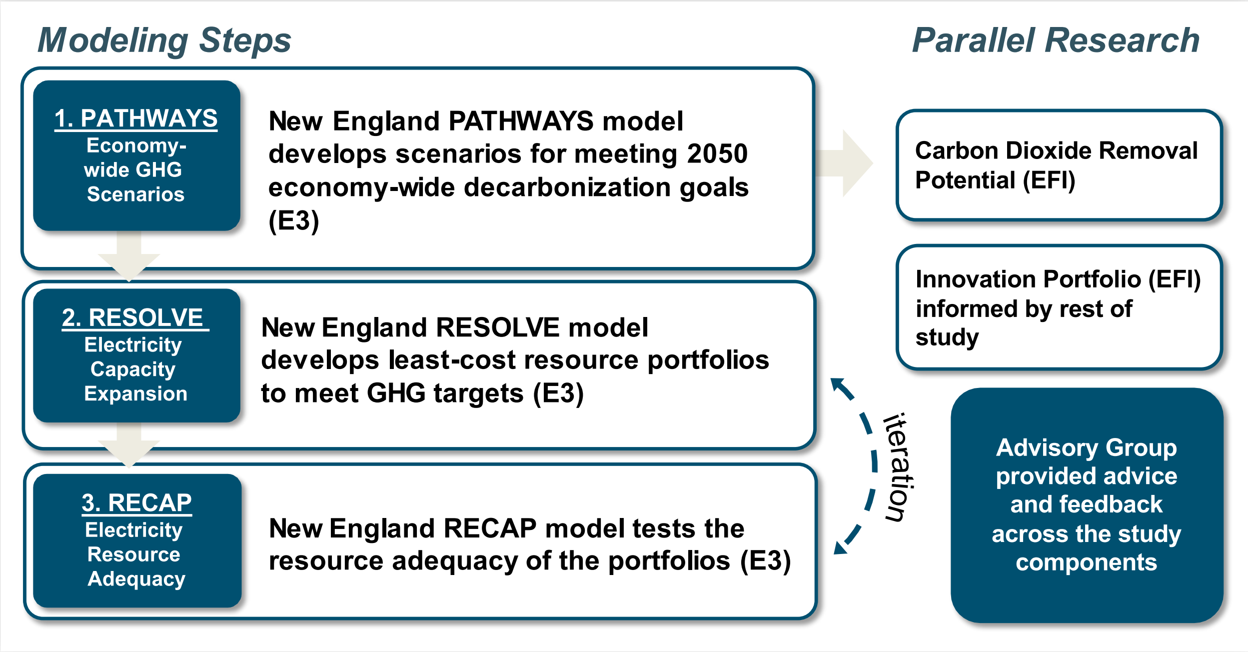
+ What decarbonization technologies and strategies are most likely to be successful in New England, given its geography, weather, policy, economics, and other regional considerations?
+ How much must electricity sector emissions fall by 2050 to support economy-wide net-zero emissions goals?
+ How much additional electric load will materialize due to the electrification of end-uses between now and 2050?

+ What is the cost-optimal electricity resource mix, subject to reasonable limitations on resource availability, to meet New England's energy and resource adequacy needs through 2050 while achieving economy-wide GHG goals?
+ What roles do various electricity supply resources play in achieving resource adequacy?
+ What are critical areas for innovation breakthroughs that can contribute to deep decarbonization and maintaining electric reliability?

1.3 Study Design

This study uses a combination of analytical approaches to illuminate the challenges of deep decarbonization in New England (Figure 1-2). Three computer models maintained by E3 were used to develop reliable electricity resource portfolios consistent with net-zero economy-wide greenhouse gas emissions by 2050. The modeling is complemented by EFI's systematic assessment and prioritization of emerging innovations that could potentially support the region's net neutrality goals.

Figure 1-2. Study Design



This study was supported by an Advisory Group comprising regional experts with experience in the utility industry, environmental advocacy groups, academic institutions, regional government, and similar analysis. Participants are listed on the acknowledgements page. The Advisory Group met twice and provided valuable feedback on study design, assumptions, and draft results. This study, however, solely reflects the viewpoints of its authors; participation in the Advisory Group does not imply endorsement of any of the report's key findings or conclusions.

1.4 Report Contents

The remainder of the report is organized as follows:

- Section 2 provides study context, including a description of electricity sector reliability and an overview of existing New England GHG emissions and the policy landscape.
- Section 3 provides an overview of the modeling approach.
- Section 4 summarizes the primary modeling results.
- Section 5 provides an overview of the regional innovation potential.
- Section 6 describes the study's key findings.
- Appendices 7.1-7.7 provide additional detail on the modeling assumptions and detailed results (PATHWAYS, RESOLVE, RECAP), load profile development, and the innovation opportunities for the region.

2 Context

2.1 Electricity System Reliability

Electricity system reliability is essential for public safety, health, and the functioning of a modern economy and is expected to grow in importance as the adoption of electric vehicles and building electrification increases reliance on electricity for transportation and heat. Within the context of reliability, “resource adequacy” refers to the ability of the bulk electricity system to meet electricity demand during all hours of the year, subject to an acceptable frequency of loss-of-load events. Other factors that contribute to overall electric system reliability, such as the robustness of the distribution system to factors such as storms and squirrels, are important but not included in the definition of resource adequacy and therefore not within the scope of this study.

Electricity resource adequacy standards ensure that sufficient resources are available to meet electric load under a broad range of system conditions, including adverse load, weather, renewable generation, and generator and transmission outage conditions. The most robust approach and industry “best practice” for measuring resource adequacy uses loss-of-load-probability (LOLP) modeling, wherein available generation from all different kinds of resources and load are compared across thousands of simulated years.

The most widely used resource adequacy standard across North America, including by ISO New England (ISO-NE), is the 1-day-in-10-years or 0.1 days/yr Loss of Load Expectation (LOLE) standard. It ensures a system is planned to have sufficient generation to meet load in all but one day, every ten years, regardless of the number and duration of loss of load events that occur on that day. ISO-NE conducts LOLP modeling to determine capacity requirements to meet the 1-in-10 standard, which are then procured annually in the Forward Capacity Market. This study uses the same reliability standard to ensure resource adequacy with alternative future resource portfolios that achieve deep carbon reductions.

The LOLP studies yield a total resource capacity requirement in megawatts that satisfies the 0.1 days/yr LOLE target. This total megawatt capacity requirement can then be used to establish a target planning reserve margin (PRM), where the PRM is a measure of capacity needed over and above the expected 1-in-2 (median) peak load forecast. The PRM is necessary for three primary reasons:

1. To serve load in the event that loads are higher than the median peak due to hotter or colder than average weather;

2. To serve load in the event that some generators experience forced outages or weather-induced low production; and

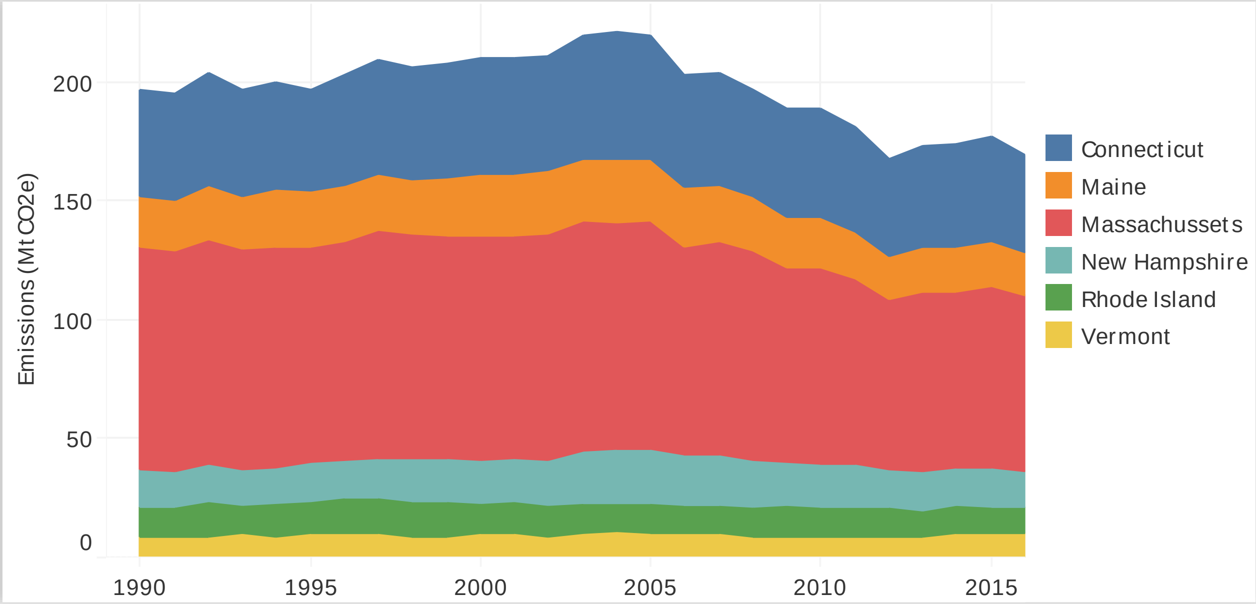
3. To provide sufficient real-time operating reserve capacity above and beyond what generation is being used to serve load.

Defining and satisfying a planning reserve margin is an essential step for markets and resource planners to ensure the electricity system is sufficiently reliable. The process of estimating the PRM and the effective capacity contributions of specific resources toward the PRM is described in more detail in Section 3.5.

2.2 New England's Greenhouse Gas Emissions

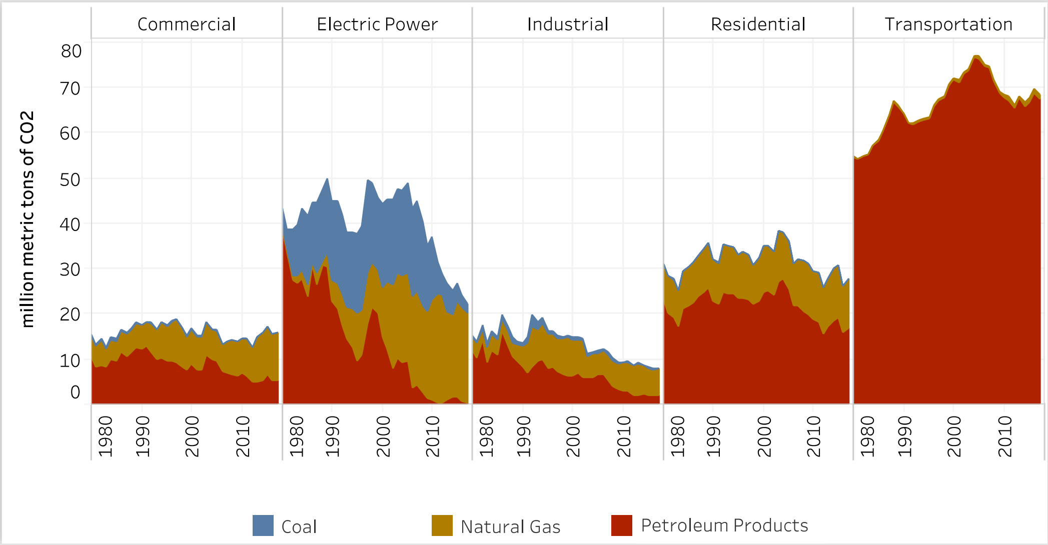
New England GHG emissions in 2016 (the latest year with published estimates from all states) equaled 170 million metric tons of CO_2-equivalent (MMT CO_2e), roughly 3% of the U.S. total. Emissions from the region declined from 2005 to 2012 but have been relatively flat since then (Figure 2-1). Massachusetts is about 44% of total New England emissions, primarily due to its larger population. Every state besides Vermont has seen gross emissions reductions since 1990, aided by the power sector transition from coal to natural gas. In 2017, all six New England states had lower per-capita energy consumption than the national average, with Rhode Island having the lowest in the country.[3] Figure 2-2 provides total GHG emissions by sector. The largest emitting sector is transportation, followed by electric power.

Figure 2-1. Historical Economy-wide GHG Emissions by State Since 1990



Source: Benchmarking based on EIA State Carbon Dioxide Emissions Data and state emissions inventories (2016).

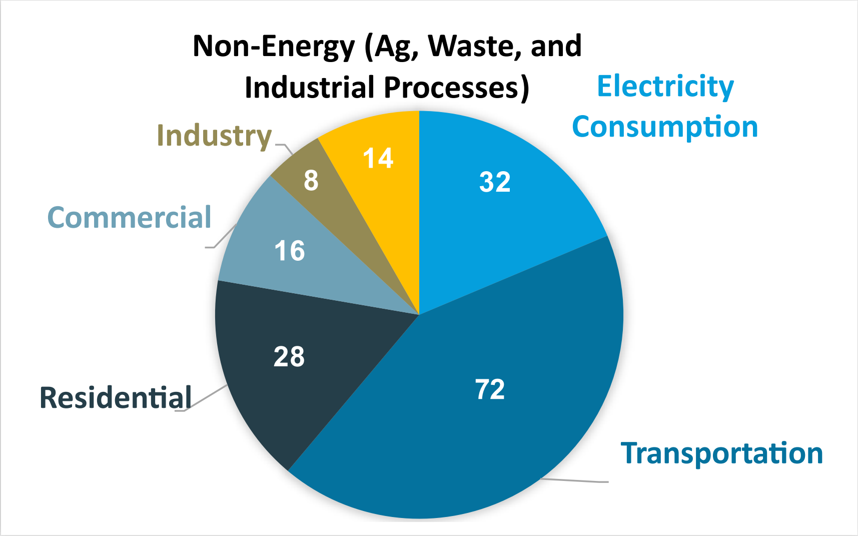
Figure 2-2. Carbon Dioxide Emissions from Fossil Fuel Combustion in New England Since 1990



Notes: Given the limited availability of historical data, this figure only accounts for emissions from the electric power sector for combustion occurring within the New England region; imports from other regions increase the total New England emissions associated with electricity consumption. For the subsequent analysis in this study, import emissions are included based on recent year benchmarking. Thus, imports are reflected in Figure 2-3 and used in PATHWAYS analysis that follows. Source: EIA State Carbon Dioxide Emissions Data, 2017.

Figure 2-3 shows emissions from electricity consumption from in-state generation and imports; thus, Figure 2-3 has a higher electricity-related greenhouse gas emissions total than that shown in Figure 2-2.

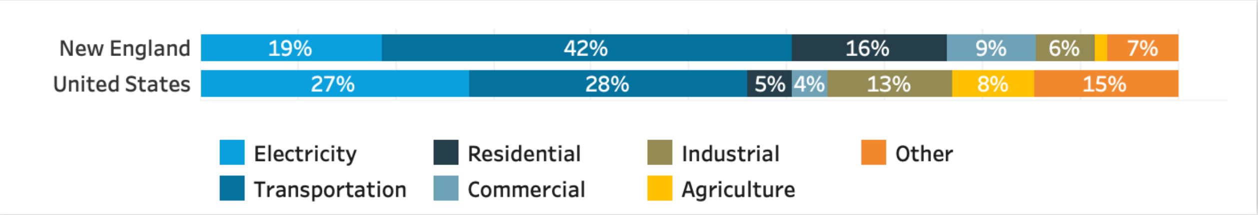
Figure 2-3. 2016 Greenhouse Gas Emissions in New England (MMT)



Note: In the above figure, electricity sector emissions have been adjusted to reflect imports, thus reflecting total electricity consumption, consistent with GHG accounting used in this study.

Figure 2-4 provides a comparison of 2016 emissions profiles for New England and the United States. Transportation is the largest source of carbon emissions in New England (42%) while electricity accounts for approximately 20%.

Figure 2-4. 2016 Greenhouse Gas Emissions Profile for New England and United States



Notes: Other includes waste, non-combustion, and industrial processes and product use (IPPU). Transportation, electrical generation, building heat, and industry account for nearly all of New England's emissions. Source: EIA, 2016; state emissions inventories, 2016.

Fossil fuel combustion for residential and commercial heat contributes a quarter of New England's emissions. The residential sector in New England has seen declining emissions overall since the early 2000's, with most of that decline attributable to fuel switching away from petroleum.[4] The commercial sector has similarly seen a decline in petroleum emissions, which has been somewhat offset by increases from natural gas emissions.

The region's residential and commercial buildings energy use is dominated by heating loads, more than any other region of the country. While in every other region of the country the majority space heating fuel for homes is either natural gas or electricity, in New England, the most common fuel is fuel oil/kerosene, with natural gas a close second.[5] The proportion using fuel oil/kerosene is more than twice as high as any other Census division. New England also has a higher proportion of homes using wood than any other Census division, the second-highest proportion using propane, and the *lowest* proportion using electricity.

The commercial sector's energy breakdown is more in line with the rest of the country, with natural gas (the main source of emissions) and electricity being the top two energy sources.[6] The commercial sector shares some of the unique characteristics of the residential sector, however. Space heating made up about half of commercial energy use in New England in 2012, a greater fraction than in any other part of the country.[7] The New England commercial sector uses more fuel oil than that of any other Census division, despite having the *lowest* overall commercial energy use.[8]

Emissions from transportation grew throughout the 1990's and early 2000's, declined as a result of the Great Recession, and ticked up again after 2012.[9] In general, the character and trends in the New England transportation sector look similar to that of the U.S. as a whole, though transportation emissions contribute a greater proportion of the total in New England.[10]

The region has few industrial emissions relative to the rest of the country. Several subsectors within the industrial sector are among the more difficult to decarbonize, usually because they require high-temperature heat, have a high degree of process integration, or produce process emissions.

2.3 Additional Policy Context

New England has been a longstanding leader in addressing climate and energy issues through regional policy coordination as well as individual state level commitments to reducing emissions. In 1990, Connecticut passed the nation's first law advancing GHG reductions to mitigate climate change.[b] The Conference of New England Governors and Eastern Canadian Premiers (NEG-ECP) adopted a regional Climate Change Action Plan in 2001, the first international agreement on mitigating climate change to be officially adopted anywhere in the world. The six New England states were also among the founding members of the Regional Greenhouse Gas Initiative (RGGI), the first cap-and-trade program for GHG emissions in the United States.

In addition to action at the state level, several local governments in New England have implemented GHG reduction policies. Boston and Providence, two of the region's three most populous cities and capitals of their respective states, set targets to reach net-zero emissions by 2050 before any states in the region did the same.[11,12] Montpelier, the capital of Vermont, has set an even more ambitious goal of carbon neutrality by 2030.[13]

[b] Connecticut's Public Act 90-219, An Act Concerning Global Warming

2.3.1 Electricity Sector CO_2 Emissions Reduction Policies

New England's economy-wide emissions reductions goals are complemented by many other decarbonization policies. A core policy in each New England state is Renewable Portfolio Standards (RPS), which require electricity providers to meet a minimum percent of load with qualifying renewable sources. Each New England state has different targets and classifies eligible renewable resources differently.[14,c] Electricity stakeholders throughout New England have collaborated since 1971 through the New England Power Pool (NEPOOL), whose common platform for trading Renewable Energy Certificates allows states to meet their RPS targets using neighboring out-of-state resources, lowering costs for the region.[15] Each state has made significant progress towards its RPS targets to date and several have increased their targets over time. Maine now has an RPS policy of 100% by 2050, while the governors of Rhode Island and Connecticut have issued executive orders analyzing policies to achieve 100% renewable (RI) or zero-carbon (CT) electricity by 2030 and 2040 respectively[16,17,18]

In addition to the RPS goals, Massachusetts established an Alternative Portfolio Standard (APS) in 2009, which complements its RPS by including additional eligible sources that are not necessarily renewable but contribute to the state's clean energy goals through reducing the need for fossil fuels, such as combined heat and power (CHP), efficient steam, and flywheel-based energy storage.[19] Massachusetts also created a clean energy standard (CES) in 2018, which requires 80% of its electricity to be procured from non-emitting sources by 2050. This policy provides an opportunity for nuclear, natural gas with carbon capture, and other low-carbon resources in addition to renewable sources to contribute to the state's decarbonization ambitions.

In addition to state-level policies, New England continues to work collaboratively to implement regional policies like RGGI. Carbon allowance sales under the cap-and-trade program have spurred regional emissions reductions and raised nearly $3.5 billion since its first allowance auction.[20]

2.3.2 Other Sector-Specific GHG Reduction Policies

The early regional focus on a cap-and-trade program for the power sector has paved the way for similar actions focused on the transportation sector. New England states currently participate in the Transportation Climate Initiative (TCI) of the Northeast and Mid-Atlantic States. The collaborative is developing a regional cap-and-trade program for the transportation sector that could go into effect as early as 2022, a first for the United States.[21] Every New England state besides New Hampshire also adopted California's fuel economy/emissions standards, which are stricter than the federal standard.[d]

Five New England states (with the exception of New Hampshire) have signed onto a State Zero-Emission Vehicle (ZEV) Program Memorandum with other states across the U.S. to support the widespread

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[c] Several states require certain percentages of different resource types within their RPS's and some have resource procurement targets for specific individual technologies, such as solar PV or offshore wind. Massachusetts, for example, created a "Solar Carve-Out" within its RPS to support new solar PV installations beginning in 2010 and separately, set a goal for 1.6 GW of offshore wind by 2035.

[d] In March 2020, the White House revoked California's ability to create stricter-than-federal standards and implemented new, less stringent nationwide fuel economy standards, though both decisions have been challenged in court.

deployment of ZEVs.[e] The Memorandum sets a voluntary goal of 3.3 million ZEVs on the road collectively across all member states by 2025. Policies from New England identified as models for the coalition include: Rhode Island's policy of purchasing only alternative-fuel vehicles for all new vehicles in the state fleet; Connecticut's and Vermont's grant and loan programs for publicly accessible charging infrastructure; and the fleet vehicle incentive programs and commuter ZEV parking program in Massachusetts.

The New England states have also set policies for decarbonizing the buildings sector. All six states have mandatory Energy Efficiency Portfolio Standards (EEPS) that require utilities to reduce a certain percentage of their electricity and/or natural gas demand through energy efficiency measures.[22] New England states rank among the top in the United States on the ambition and scope of their energy efficiency policies and have implemented several programs to subsidize efficiency measures or the adoption of clean technologies like distributed solar.[23] Ambitions for building decarbonization policy continue to increase, with Maine targeting the deployment of 100,000 heat pumps by 2025, requiring nearly triple historical annual sales.[24]

2.3.3 Regional Challenges to Siting New Clean Energy Infrastructure

Siting major infrastructure projects is a difficult proposition in every part of the country. The challenge in New England is amplified by a patchwork of protected lands and the region's emphasis on preserving natural landscapes.

Most of New England's land area is dominated by forests, with densely clustered cities in the south and some agricultural land spread throughout and in western Vermont. Since many forest areas are protected, the abundance of undeveloped land does not translate to plentiful sites for greenfield energy project development. The limited amount of prime agricultural land means that farmers may also be unwilling to sell or lease their property for energy development.[25] Siting pipeline or transmission projects, which must find unbroken pathways of contiguous land on which to build, is even more difficult. Long waterways like Lake Champlain in Vermont may present opportunities for submerged transmission projects.[26]

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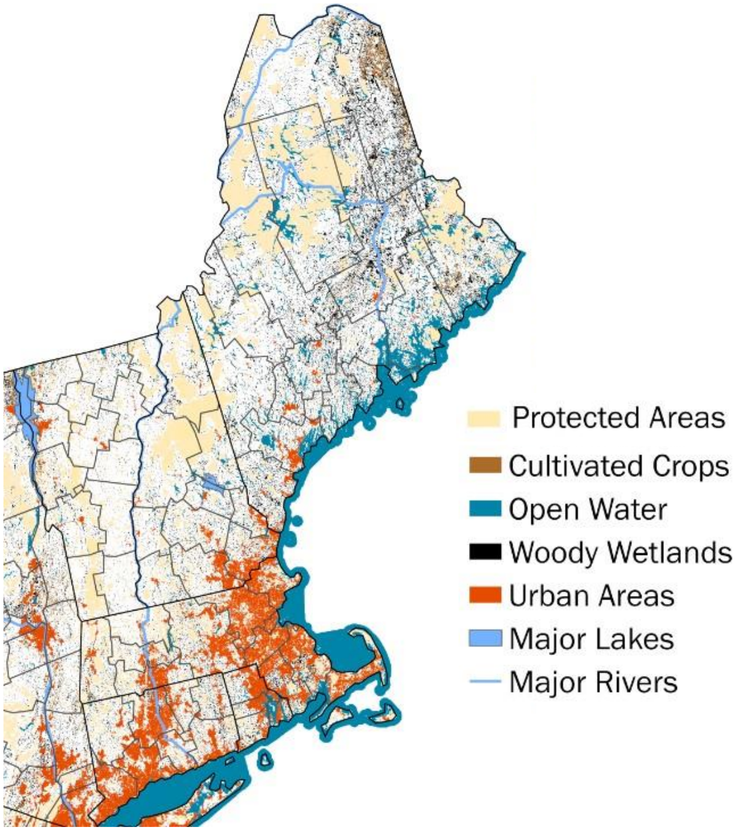
[e] Other signatories include California, Oregon, New York, Maryland, and New Jersey.

Figure 2-5. Protected Land in New England[27,28,29,30]



New England is a checkerboard of protected land, presenting challenges for land-intensive projects. Even outside of formally protected areas, conservationists may object to proposed development.

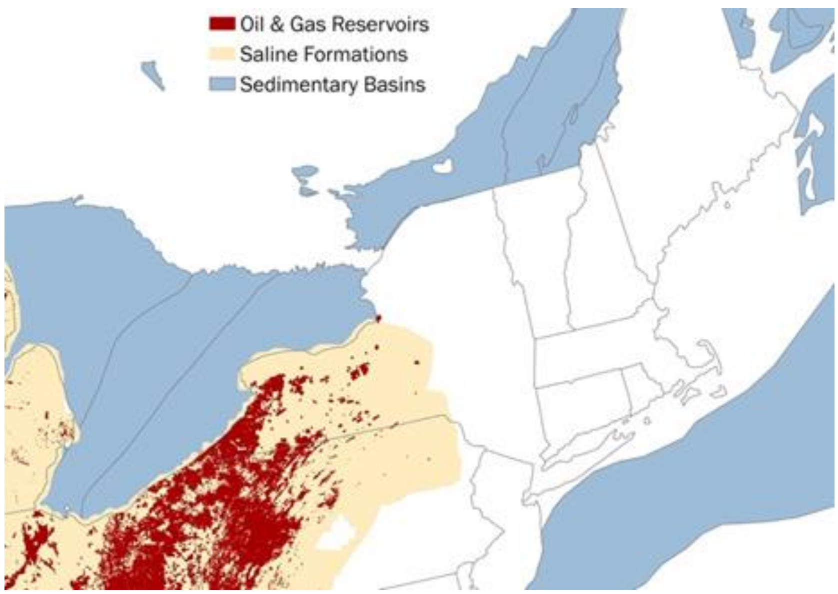
The challenges to siting new clean energy infrastructure in the region have led to the cancellation and delay of many projects over the past few years.

- Utilities in Massachusetts have repeatedly attempted to build a high-voltage DC line to draw electricity from Quebec's hydroelectric dams for over a decade; the most recent attempt was put to referendum in November 2020.[31],[32]
- Maine has long dealt with inadequate transmission capacity as a barrier to local wind resources. In 2009 the state set a goal of 3 GW by 2020.[33] The state has just under 1 GW today, owing to continued transmission congestion and persistent backlogs of interconnection requests that continue today.[34,35] Local siting opposition has also stalled progress. [36]
- Fierce opposition to offshore wind projects led to multiple projects failing in the early 2000s.[37,38] Ongoing federal permit delays stemming from opposition from the fishing industry continue to stall the most recent projects.[39]

- Tensions between solar developers and rural communities wishing to maintain natural lands and viewsheds threatens to slow the solar boom that has occurred over the last decade since.[40]

The geology underlying New England is generally unsuitable for the geological sequestration of carbon dioxide (Figure 2-6). This makes carbon capture in industry, electrical generation, or negative emission systems difficult or impossible without moving the captured carbon to neighboring locations. Long-distance CO_2 pipelines to distant injection sites may face the same siting issues that most large infrastructure projects in the region confront. Though there is a possibility of offshore sequestration, this is unproven and likely to be very costly.

Figure 2-6. Geological Sequestration Resources in the United States near New England



New England lacks the most suitable geological formations for carbon sequestration. Unless it becomes cost-effective and practical to sequester CO_2 offshore or pump it to neighboring states, CCS use in New England is likely to be minimal.

3 Modeling Approach

3.1 Scenario Development

This study examines New England's long-term electricity sector reliability needs under scenarios consistent with achieving net-zero GHG emissions across the region's economy by 2050. Net-zero is modeled as a direct emissions reductions goal of 85% relative to 1990 levels by 2050, and an assessment of how innovation and carbon dioxide removal (CDR) can address the remaining 15% .[41,f]

The two net-zero scenarios developed for this study include one focused on high electrification of energy consuming sectors, and one in which electrification is pursued at lower levels, instead relying on higher levels of fossil fuel substitution with currently emerging low-carbon fuels, such as advanced renewable biofuels and hydrogen. While these low-carbon fuels are not yet commercialized, they may be important levers to decarbonizing harder-to-abate emissions in deep decarbonization pathways.

+ **High Electrification Scenario:** This mitigation scenario electrifies most space and water heating within buildings, as well as most light-duty vehicles (LDVs). The modeling also includes increased adoption of electric and hydrogen vehicles in medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) as well as electric space heating and water heating appliances in buildings, and electrification of feasible industrial processes. This scenario assumes that hydrogen becomes commercially available in the power sector as zero-carbon replacement for natural gas.
+ **High Fuels Scenario:** This mitigation scenario includes lower levels of electrification in favor of higher shares of low-carbon fuels, including advanced renewable biofuels and hydrogen in sectors such as freight transportation (MDV and HDV), buildings, and industrial end uses. This scenario also assumes an expanded low-carbon fuel market emerges, in which hydrogen becomes commercially available at lower prices within the power sector than in the High Electrification scenario.

The scenarios are structured to reflect the likely range of electricity sector resource adequacy needs under New England's long-term deep decarbonization policies. The High Electrification scenario shifts much of the decarbonization requirements onto the power sector as greater amounts of direct energy use are electrified; the greater reliance on decarbonized fuels such as hydrogen and renewable biofuels in the High Fuels scenario moderates the growth of electrification loads.

These economy-wide scenarios generate the inputs to the electricity sector reliability and capacity expansion modeling, namely total load and total electricity sector emission targets. These scenarios are modeled under a base set of assumptions and then evaluated under a range of sensitivities described in Section 3.4.

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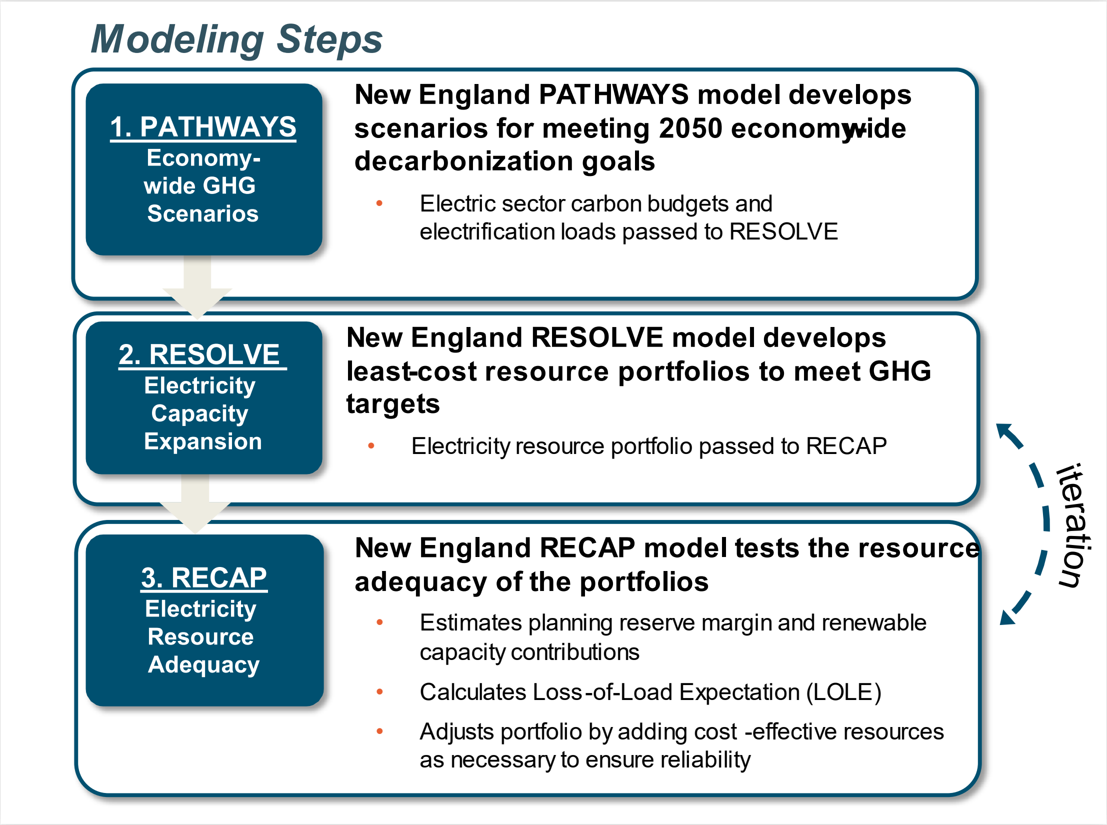
[f] The relative contribution of direct abatement and carbon dioxide removal is commensurate with the state of Massachusetts' recent determination, and consistent with the IPCC's analysis of global emissions trajectories to cap temperature rise to 1.5 C. Specifically, three IPCC global emissions scenarios commensurate with the 1.5 C target have direct abatement of roughly 80% of global emissions between 2010 and 2050, with the carbon dioxide removal—mostly bioenergy with carbon capture and storage—bringing net emissions to zero.

3.2 Modeling Framework

This study utilizes three well-established E3 models – PATHWAYS, RESOLVE, and RECAP – which have been used extensively by state agencies, utilities, and regulators across the U.S. to study deep decarbonization topics. The PATHWAYS model is used to develop economy-wide GHG emission scenarios across the New England region. The resulting electric sector loads and GHG targets are then used in the electricity-specific RESOLVE and RECAP models. RESOLVE is a capacity expansion model that optimizes generation and transmission investments subject to reliability, technical, and policy constraints. RECAP is a resource adequacy model that performs loss-of-load probability simulations to determine the reliability of resource portfolios. An overview of the modeling approach is shown in Figure 3-1.

Figure 3-1. Modeling Approach



3.3 New England PATHWAYS Model

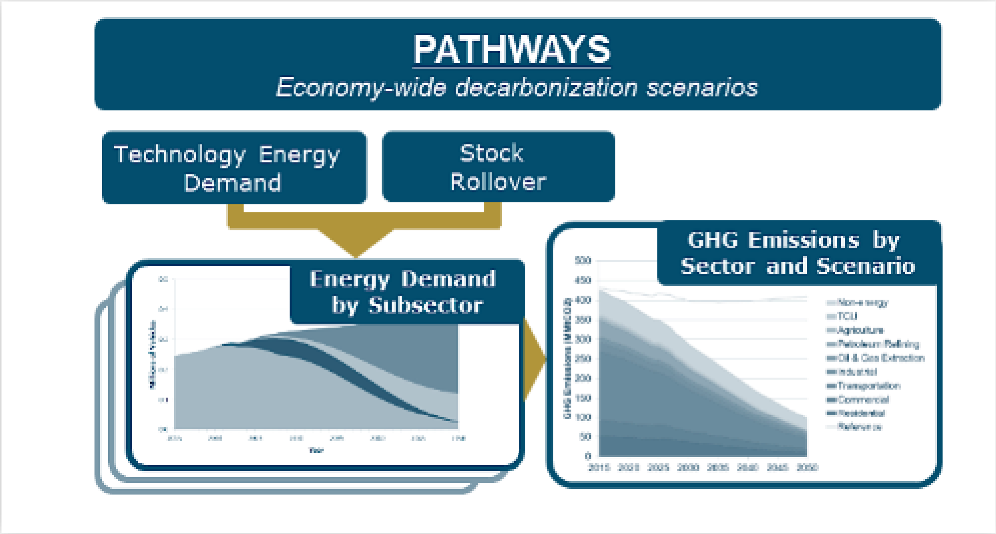
3.3.1 Overview

The New England PATHWAYS model is an economy-wide representation of infrastructure, energy use, and emissions within a specified geography. E3 developed PATHWAYS in 2008 to help policymakers, businesses, and other stakeholders analyze trajectories to achieving deep decarbonization of the economy, and the model has since been improved over time in projects analyzing jurisdictions across North America. Recent examples include working with the California Energy Commission, NYSERDA in New York, Xcel Energy in Minnesota, and Nova Scotia Power in Nova Scotia.

We defined the greenhouse gas emissions that the region is responsible for by aligning with state inventory accounting frameworks and using federal data on energy use from the Energy Information Administration (EIA) State Energy Data System (SEDS). The emissions accounting frameworks are broadly consistent with Intergovernmental Panel on Climate Change (IPCC) guidelines. In brief, these include emissions associated with energy use in residential and commercial buildings, transportation, and industry; electricity generation within the region; net imports of electricity; and non-combustion emissions associated with industrial processes, agriculture, and waste processing.

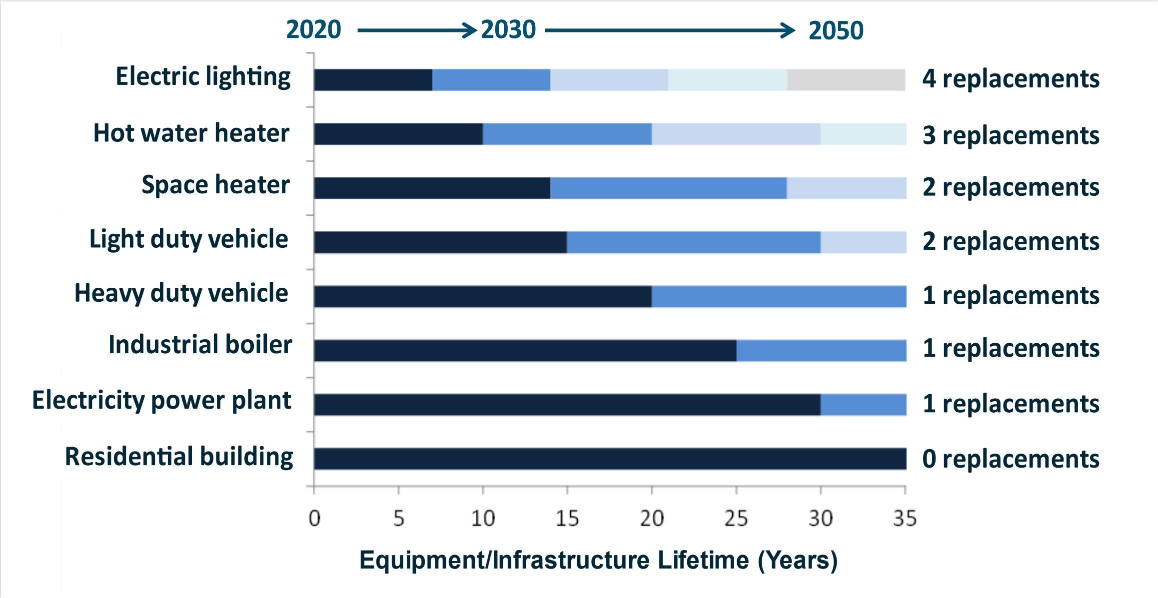
We model energy-related emissions sources, and projected energy demand and economy-wide emissions through 2050. In this study, PATHWAYS includes a calculation of direct energy use and emissions associated with direct energy use; the emissions associated with electricity generation are tracked within the RESOLVE model. PATHWAYS includes both supply and demand sectors to capture interactions between the sectors, and the focus is on comparing user-defined policy and market adoption scenarios and to track physical accounting of energy flows within all sectors of the economy.

Figure 3-2. Illustration of PATHWAYS Model Framework



A key feature of PATHWAYS is a characterization of stock rollover in major equipment categories (specifically in buildings and transportation fleets). A stock rollover approach tracks infrastructure turnover of energy consuming devices while accounting for changes in performance, such as improved efficiency over time; this explicitly tracks the time lag between changes in annual sales of new devices and change in device stocks over time. Different technologies have different lifetimes, which are captured by this approach. For example, some technologies, such as lightbulbs, might have life spans of just a few years while others, such as building shell systems, might have lifespans at the decadal scale. Tracking technology and infrastructure lifespans informs the pace necessary to achieve economy-wide GHG targets while capturing potential path dependencies.

Figure 3-3. Illustrative Device Lifetimes for Stock Rollover Methodology in PATHWAYS



3.3.2 Key Assumptions

Table 3-1 summarizes the key measures used in constructing each of the mitigation scenarios within the New England PATHWAYS model. As the table demonstrates, the High Electrification scenario assumes greater electrification across all sectors, while the High Fuels scenario uses hydrogen or advanced biofuels in end uses where these are most likely to be available and cost effective. Both scenarios assume significant energy efficiency, including complete lighting replacement of incandescent with LEDs and all new appliance sales being highly efficient EnergyStar+ grade appliances by 2030. Both scenarios also include significant weatherization and building shell upgrades, which reduce the space conditioning demands of residential and commercial buildings. More information about these scenarios are available in Appendix 7.1.

Table 3-1. Key Mitigation Measures in 2050

<table>
<tr><th>Sector</th><th>Sub-Sector</th><th>High Electrification Scenario</th><th>High Fuels Scenario</th></tr>
<tr><td rowspan="3">Transport</td><td>Light duty vehicle (LDV)</td><td colspan="2">100% of light duty vehicle sales are battery electric or plug-in hybrid electric (91% LDV stock by 2050); 7% reduction in VMT</td></tr>
<tr><td>Medium and heavy duty vehicle (MDV, HDV)</td><td>90% MDV sales are electric
50% HDV sales are electric and 50% are hydrogen fuel cell</td><td>70% MDV sales are electric
100% HDV sales are hydrogen fuel cell vehicles</td></tr>
<tr><td>Other transport</td><td>FAA CLEEN 2[g] generates 40% efficiency gain relative to no efficiency counterfactual
90% of non-aviation fossil end uses are converted to electricity</td><td>FAA CLEEN 2 generates 40% efficiency gain relative to no efficiency counterfactual
10% renewable jet kerosene in aviation fuel; 15% renewable diesel</td></tr>
<tr><td rowspan="3">Buildings</td><td>Appliances & Efficiency</td><td colspan="2">100% of buildings adopt Energy Star + Grade appliances
60% of buildings have efficient shells (part retrofits; all new builds)</td></tr>
<tr><td>Building Electrification</td><td>90% heat pump sales share (almost 80% res homes and over 80% commercial sq ft by 2050)</td><td>60% heat pump sales share (over 50% res. homes and over 50% commercial sq ft by 2050)</td></tr>
<tr><td>Building fuel use</td><td>80% of building energy consumption is electricity
No fuel use from renewable fuels and hydrogen</td><td>60% of building energy consumption is electricity
13% of final energy use in 2050 is from low-carbon fuels (hydrogen and RNG):
7% Hydrogen[h] by energy in natural gas pipeline
20% RNG in natural gas pipeline</td></tr>
<tr><td rowspan="2">Industry</td><td>Efficiency</td><td colspan="2">25% decrease in industry energy demand relative to counterfactual no-increased-efficiency</td></tr>
<tr><td>Electrification and fuel switching</td><td>53% of industrial energy consumption is electric
34% of industrial energy consumption from renewable fuels, hydrogen, and natural gas with CCS</td><td>39% of industrial energy consumption is electric
48% of industrial energy consumption from renewable fuels, hydrogen, and natural gas with CCS</td></tr>
<tr><td>Low carbon fuels[i]</td><td>Advanced biofuels fuels and hydrogen (outside power sector)</td><td>34 TBtu of hydrogen (excluding power sector use, which is incremental), used in transportation (no hydrogen in natural gas pipeline), and no advanced biofuels</td><td>140 TBtu of advanced biofuels used; about 80 TBtu of hydrogen use (excluding power sector use, which is incremental), in both transportation and within pipeline (7% hydrogen by energy)</td></tr>
<tr><td>Electricity</td><td>% Zero-carbon MWh</td><td colspan="2">95% estimated (iterations & modeling conducted in RESOLVE)</td></tr>
<tr><td>Non-combustion emissions</td><td>Industrial processes, agriculture, and waste</td><td colspan="2">6 MMT emissions reductions (75% emissions reduction) in ozone-depleting substances and methane emissions from natural gas leakage, with no emissions reductions from agriculture or waste</td></tr>
</table>

[g] Federal Aviation Administration Continuous Lower Energy, Emissions, and Noise Program Phase 2

[h] 7% hydrogen by energy in natural gas distribution pipeline is equivalent to about 20% by volume which is assumed to be the maximum allowable blend wall before significant pipeline upgrade costs are required.

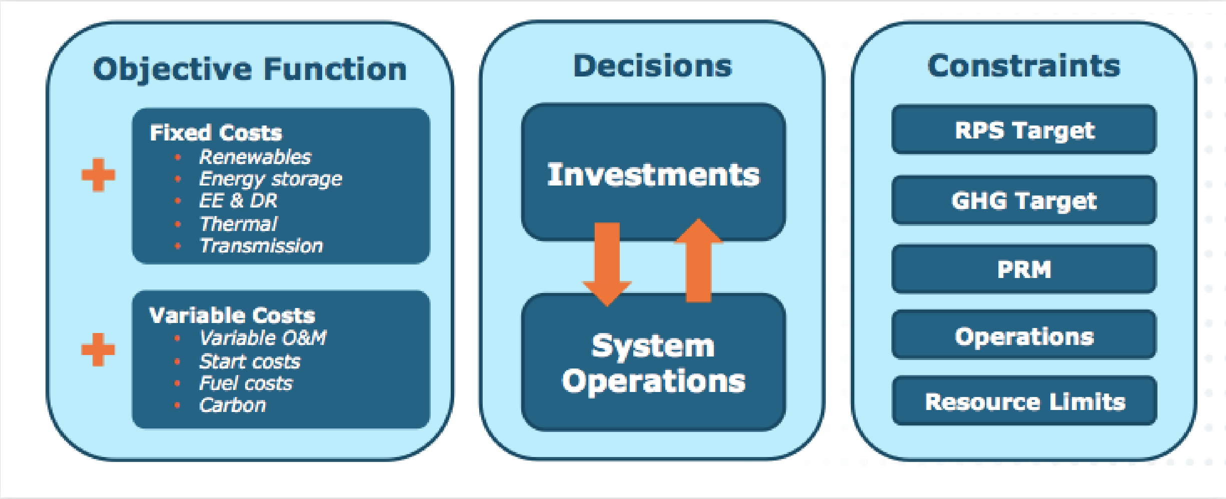
i Note that the power sector burns additional hydrogen beyond the amount of hydrogen used in the other sectors of the economy. Power sector hydrogen burn is endogenously selected by the model and varies by scenario.

3.4 New England RESOLVE Model

3.4.1 Overview

RESOLVE is E3's electricity system capacity expansion model that identifies optimal long-term generation and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments vs. renewable curtailment/overbuild. The model uses weather-matched load, renewable and hydro data and simulates interconnection-wide operations over a representative set of sample days in each year. The model captures the dynamic contribution of renewable and energy storage resources to the system that vary as a function of their penetration, specifically in terms of capacity requirements toward the planning reserve margin. The objective function minimizes net present value (NPV) of electricity system costs, which is the sum of fixed investment costs and variable plus fixed operating costs, subject to various constraints. Figure 3-4 provides an overview of the model.

Figure 3-4. Overview of RESOLVE Model



RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to technologies commercially available today. This approach ensures that the GHG reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. The full range of resource options considered by RESOLVE in the "Base Case" is shown in Table 3-2 below. Gas generation with CCS is only available in a sensitivity.

Table 3-2. Resource Options Considered in the New England RESOLVE Model

Candidate Resource Option	Available Options	Functionality
Renewable Generation	+ Onshore wind + Offshore wind + Utility scale solar PV + Distributed solar PV	+ Variable generation, generates as available + Can be curtailed at no cost + Detailed supply curves with land constraints
Energy Storage	+ Lithium batteries (4+ hour)	+ Stores excess energy for later dispatch + Contributes to meeting reserve requirements and ramping needs
Canadian Hydro[j]	+ Turbine upgrades (tier 1) + New impoundments (tier 2)	+ Dispatches economically up to an energy budget, subject to min and max flow constraints + Contributes to meeting operating reserve requirements
Nuclear	+ Advanced nuclear	+ Dispatches economically, subject to ramping limitations + Contributes to meeting reserve requirements + Limited to existing NE nuclear capacity in Base Case
Flexible Loads	+ Models shift demand response	+ Allows the model to shift load from one timepoint to another (e.g., reflecting future potential managed charging or advanced demand response)
Natural Gas Generation[k]	+ Simple cycle gas turbines (peakers) + Combined cycle gas turbines	+ Dispatches economically based on heat rate, subject to ramping and min off/on limitations + Contributes to meeting reserve requirements and ramping needs + Gas turbines can burn clean drop-in fuel (assumed hydrogen for this study) at a fuel cost premium + Can be coupled with Carbon Capture and Storage in sensitivity runs (not in Base Case)

In addition to selecting new resources, RESOLVE can retire existing resources that it finds uneconomic. A resource is uneconomic if the going-forward costs of maintaining the resource are greater than the fuel, O&M, ancillary service and capacity savings the resource produces when operating.

[j] We note that for purposes of this study, Canadian Hydro resources are assumed to be zero-carbon. That said, there is some ongoing debate regarding emissions from this source, given hydro resources do emit GHGs[135] and the concern regarding the actual additionality of Canadian Hydro., i.e., its delivery to New England may displace deliveries and result in increased use of fossil fuels outside of New England.

[k] While many vendors have suggested that gas combustion turbines will be able to utilize various hydrogen blends with some modest capital upgrades, we do not explicitly model these costs. We note that in this modeling, these units select to burn blends of hydrogen only in the 2050 model year (given costs and carbon trajectories). We also note that the technology to burn 100% hydrogen fuel in a gas combustion turbine is not currently commercially available.

RESOLVE is not designed to answer detailed resource adequacy questions in systems without sufficient firm capacity. The RESOLVE modeling framework is limited to a set of representative sample days which do not contain enough data points to make robust conclusions on reliability events that happen infrequently (potentially less than once per year). In addition, the sample days are independent (i.e., not connected) and therefore do not capture the potential need for multi-day or seasonal storage. This type of long-duration storage could be extremely important in a system without sufficient firm capacity. RESOLVE does include a Planning Reserve Margin (PRM) constraint to ensure that sufficient resources are maintained to meet an assumed long-run reliability standard, but the PRM standard is developed exogenously and incorporated into RESOLVE as an assumption. For this reason, the RESOLVE analysis is supplemented with a detailed reliability analysis using RECAP as described in Section 3.5.

3.4.2 Key Assumptions

The New England RESOLVE model, customized for this region as part of this study, relies on inputs and assumptions from various publicly available sources, ranging from regional reports published by ISO-NE to resource data developed by the National Renewable Energy Laboratory (NREL). Table 3-3 provides a summary of key RESOLVE inputs for the New England model. For a more detailed description of assumptions, including baseline resources, candidate resource costs, performance, and potential, refer to Appendix 7.5. Below the table, we also describe key modeling constraints designed to reflect important features of the New England region and electricity system.

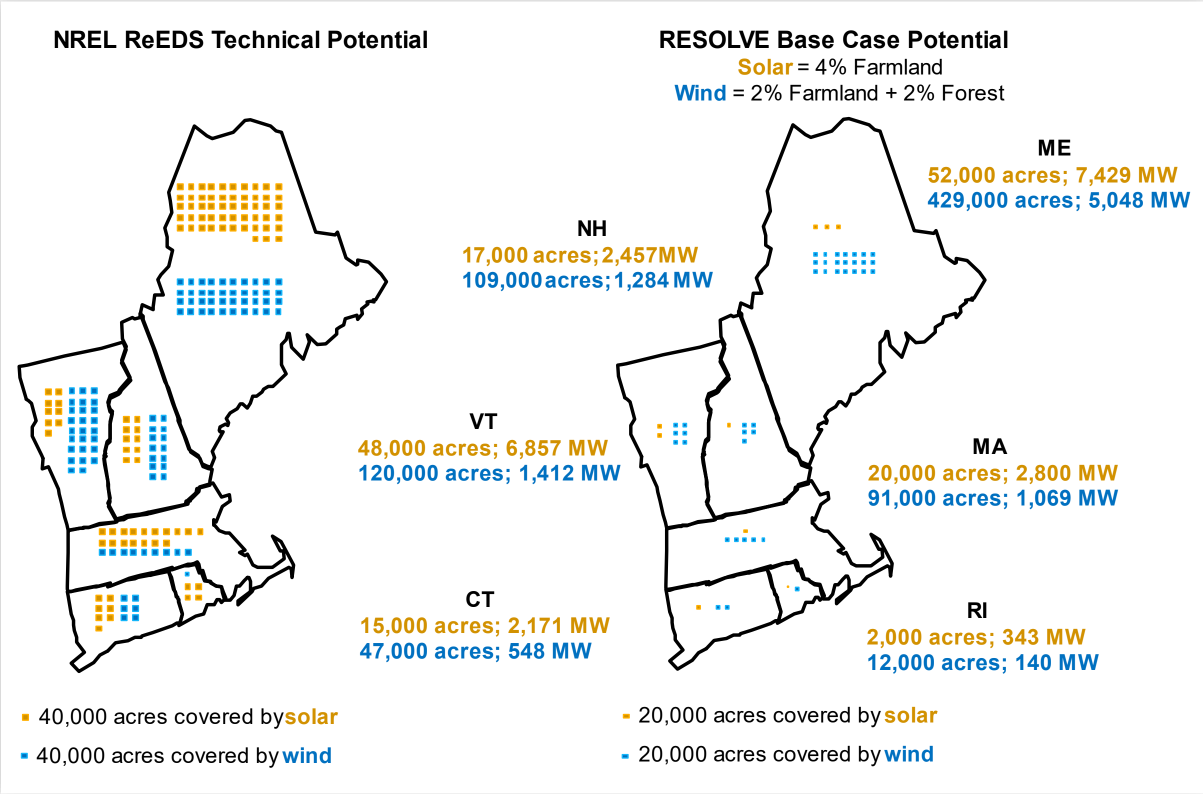
Table 3-3. Summary of Key RESOLVE Assumptions and Sources

Category		Description / Source
Area	Geographical footprint	ISO-NE service territory
	Topology	Single electrical load zone (ISO-NE) and three external electrical zones (New York, Quebec, and New Brunswick)
Loads	Annual energy (2025 – 50)	PATHWAYS model results; see Section 4.1.
	Peak demand (2025 – 50)	PATHWAYS model results; see Section 4.1
	Planning reserve margin	10.2% on an unforced capacity (UCAP) basis (calibrated to ensure adherence to ISO-NE's '1-in-10' reliability standard)
GHG Reduction Policy	Power sector emissions target	High Fuels scenario: 1.9 MMT (~95% of MWh carbon-free) High Electrification scenario: 2.5 MMT (~95% of MWh carbon-free, but higher cap given more load than above)
	RPS policy	Load-weighted RPS from all six NE states (~50% by 2050)
Fuel Cost	Natural gas	Algonquin hub price projections in both short term (gas future contracts) and long term (EIA forecast). See Appendix 7.4 for chart.
	Coal, uranium, oil	EIA Annual Energy Outlook 2020
Zero-Carbon Fuel	Hydrogen	Costs based on production, storage, and delivery of renewable hydrogen to the New England region. See Appendix 7.1 and Figure 7-3.
Existing Resources	Generators & imports	ISO-NE 2019 Capacity, Energy, Loads, and Transmission (CELT) report
Renewable Potential	Onshore renewables (Solar and onshore wind)	NREL ReEDS supply curves supplemented with land area restrictions: solar PV (4% of total farmland), onshore wind (2% of total forest and farmland)
	Offshore wind	No restrictions applied to NREL ReEDS offshore wind supply curve
Resource Cost	In-region resources	NREL Annual Technology Baseline (ATB) 2019 costs NREL Annual Technology Baseline (ATB) 2018 costs with regional factors for solar and wind resources
	Energy storage	Lazard LCOS v5.0 report (2019)
	Canadian hydro turbine upgrades (tier 1)	Empirical estimate from past hydro turbine upgrades
	Canadian hydro new impoundments (tier 2)	Empirical estimate from past Canadian hydro projects[i]
Transmission Cost	230 kV interconnection (spur line)	NREL ReEDS spur line costs by site and project
	345 kV network upgrade (backbone)	ISO-NE resource integration studies

[i] Canadian hydropower project costs taken from Table 7 in the MIT-CEEPR's Deep Decarbonization of the Northeastern US and the Role of Canadian Hydropower paper available here.

To construct realistic estimates of potential renewable availability within New England, this analysis starts with the solar and wind technical potential values available from NREL's Regional Energy Development System (ReEDS) model, which represents all potential resources available for development after land-use screens that remove land area that is either protected or already developed (e.g., national parks or cities).[m] However, NREL's total resource potential still far exceeds what can feasibly be developed simultaneously. Thus, additional land use screens were applied in the base cases, including constraining land use for solar resources to an equivalent area as 4% of farmland, and constraining land use for onshore wind resources to an equivalent area as 2% of farmland and forest land in each state. Sensitivities testing more restrictive and unrestricted land use are also modeled and provided in Section 4.5.

Figure 3-5. Land Use Associated with Utility-Scale Solar and Onshore Wind Implied from NREL ReEDS Technical Potential and Study Farmland and Forest Screens used in Base Case



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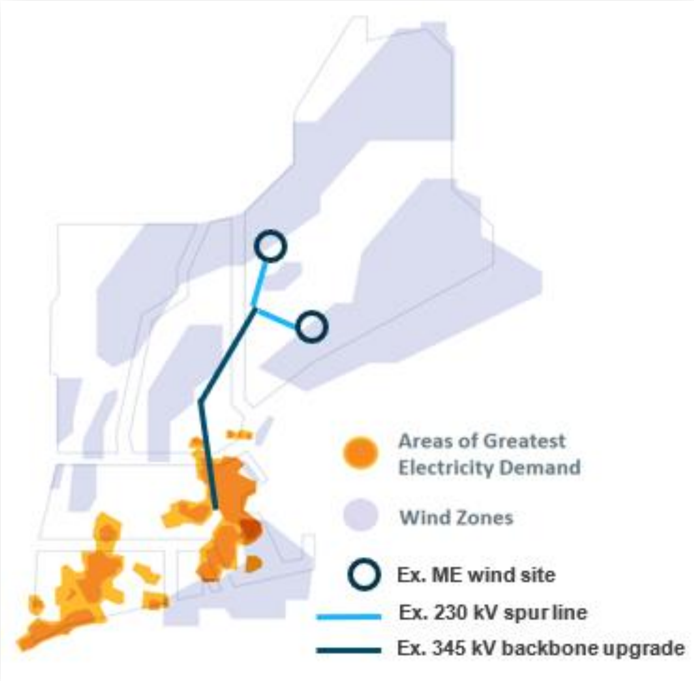
[m] The resource potential within NREL ReEDS for solar includes land located on large parcels outside urban boundaries, excluding federally protected lands, inventoried "roadless" areas, U.S. Bureau of Land Management areas of critical environmental concern, and areas with slope greater than 5%. For onshore wind, the resource potential excludes areas considered unlikely to be developed for environmental or technical reasons: federal and state protected areas (e.g., parks, wilderness areas, and wildlife sanctuaries), areas covered by water, urban areas, wetlands, airports, and rough terrain. Areas classified as non-ridge-crest forest, U.S. Forest Service and U.S. Department of Defense lands, and state forests are 50% excluded.

Another important consideration in New England is the availability and cost of transmission required to integrate renewables. Integrating large quantities of renewable energy requires significant investment in new transmission infrastructure on the bulk grid. All renewable projects, except distributed solar, are assumed to incur 230 kV interconnection (spur line) costs, which connect the project sites to the bulk grid. Additional 345 kV network upgrade (backbone) costs are also assumed to occur to transfer renewable power on new interstate transmission lines to the assumed load center (Boston), once existing headroom on the transmission system is exhausted. Additional solar resources are assumed to be consumed locally and do not count toward the existing headroom constraint.[n] An example of the types of transmission costs required to integrate a Maine wind project is shown in Figure 3-6.

Figure 3-6. Example of New Transmission Build to Integrate Maine Onshore Wind



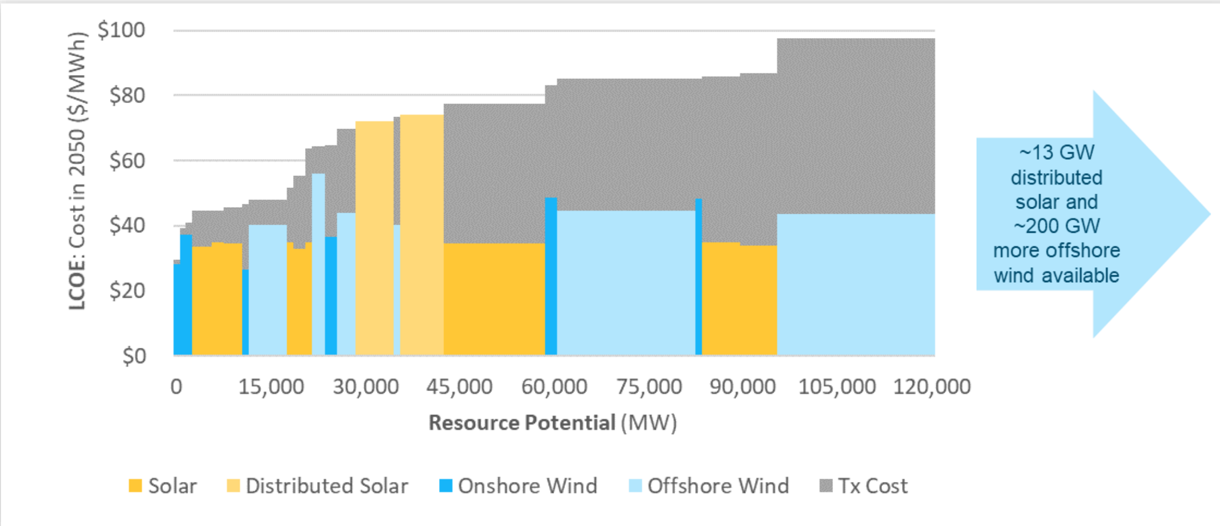
Note: The base map of demand and wind zones is from ISO-NE, with E3 illustrative wind site and transmission build layered on.

The resulting Base Case supply curve for candidate renewables is shown in Figure 3-7 below. The most economic renewable resources (left part of the curve) incur only the 230 kV spur line costs, whereas the more expensive resources (right part of the curve) incur both the 230 kV spur line costs as well as 345 kV network upgrade costs. The 230 kV interconnection costs are taken directly from the NREL ReEDS renewable supply curves previously described. The 345 kV network upgrade costs are benchmarked to

[n] Specifically, the model assumes that solar resources equivalent to 50% of 2050 peak load are available to be consumed locally in each state.

costs from regional transmission planning studies conducted by ISO-NE for integrating onshore renewables. More details on transmission requirements and costs is also available in Appendix 7.5.

Figure 3-7. Renewable Supply Curve Based on 2050 Resource Costs



Note: This figure reflects the modeling assumptions utilized in this study, including assumptions regarding resource potential and land use screens, and the transmission availability and costs.

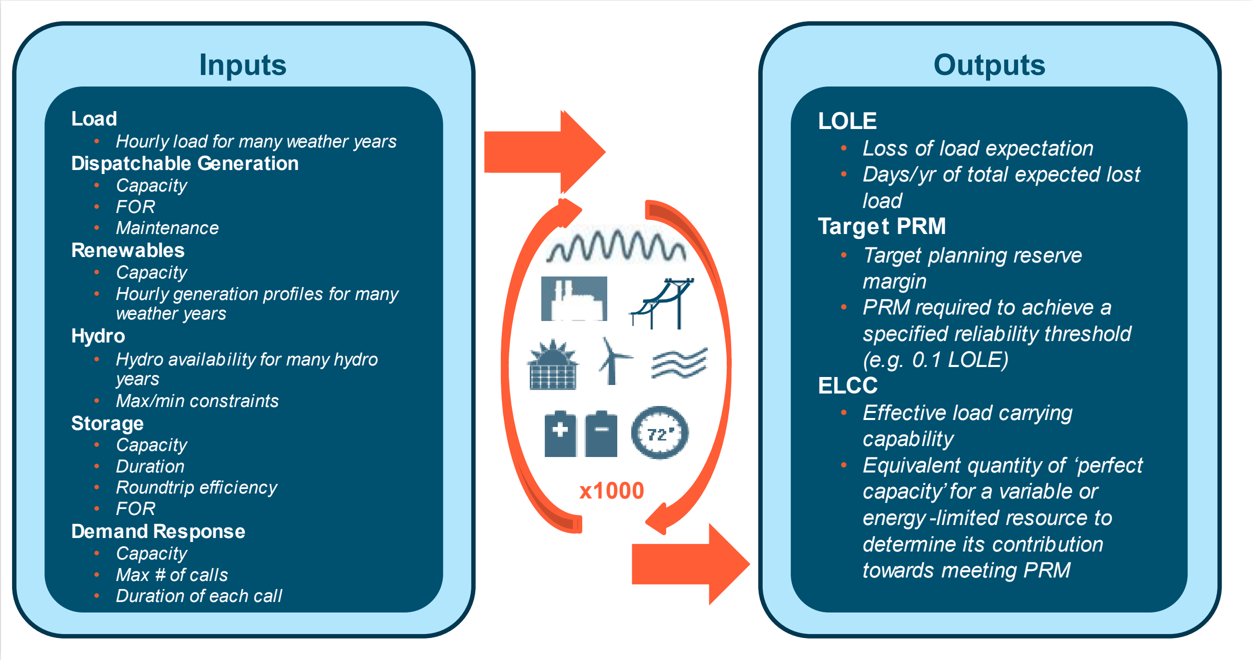
3.5 New England RECAP Model

3.5.1 Overview

RECAP is a loss-of-load-probability model developed by E3 that is used to assess the reliability of electricity system portfolios, and has been used extensively across North America, including in California, Hawaii, Atlantic Canada, the Pacific Northwest, the Desert Southwest, the Upper Midwest, and Florida. RECAP was developed by E3 specifically to evaluate the reliability of electricity systems operating under high penetrations of renewable energy and energy storage, which present unique methodological challenges that are not present in the historical reliability planning paradigm.

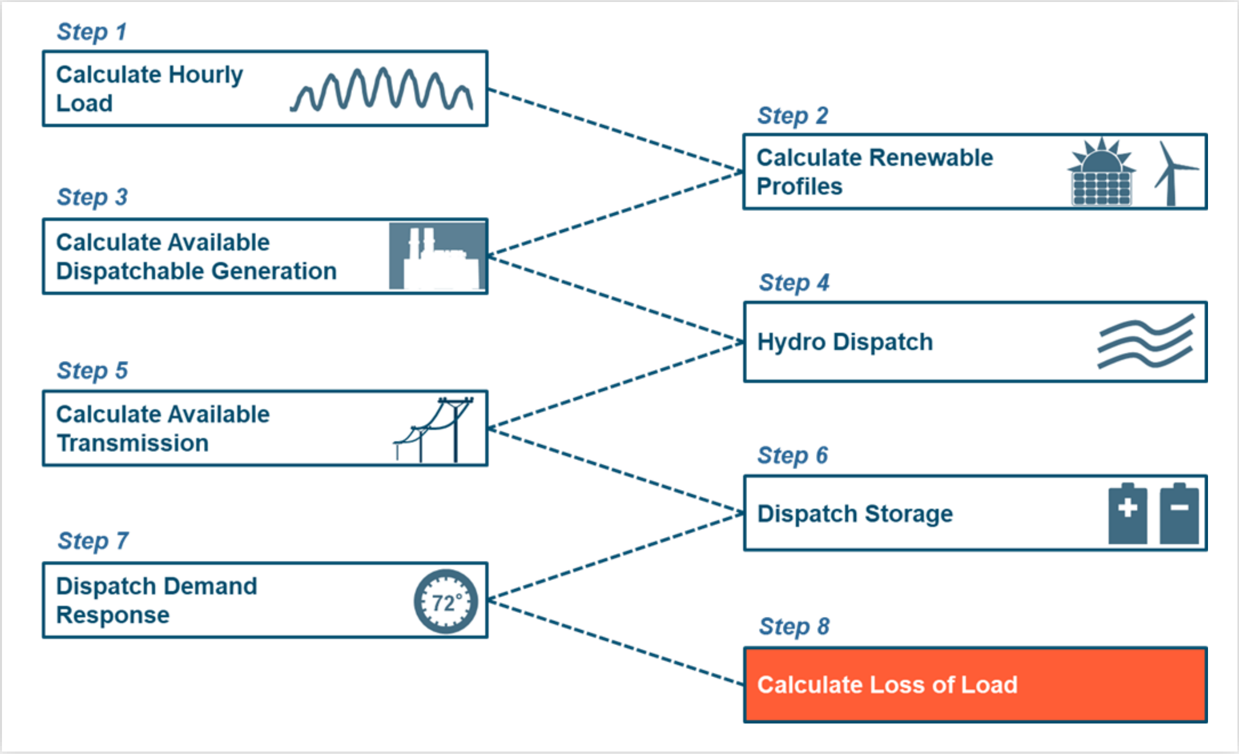
RECAP calculates a number of metrics related to reliability including loss of load expectation (LOLE), the target planning reserve margin (PRM) required to achieve the target LOLE, and the effective load carrying capability (ELCC) that quantifies the contribution of non-firm resources such as renewable energy and energy storage toward the PRM requirement. RECAP calculates these metrics by simulating electricity system resource availability with a specific set of generating resources (storage and demand-side resources included) and loads under a wide variety of weather-years, renewable generation-years, and stochastic forced outages of generation resources, and imports on transmission. By simulating the system thousands of times through Monte Carlo analysis with different combinations of these factors, RECAP provides a statistically significant estimation of LOLE. As described in Section 2.1, an electricity system with a loss of load expectation ("LOLE") that meets or exceeds the 0.1 days/year standard is deemed reliable for the purposes of this analysis. An overview of the RECAP model is shown in Figure 3-8.

Figure 3-8. Overview of RECAP Model



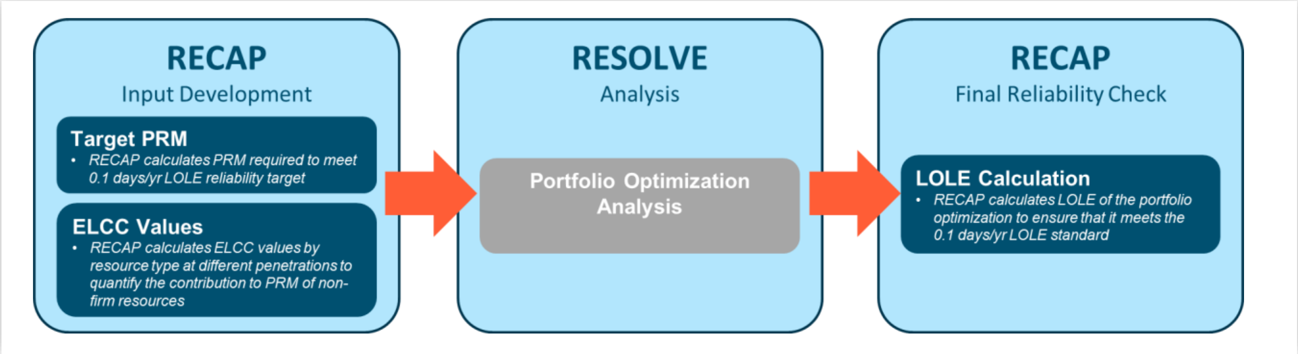
Several aspects of RECAP are designed specifically to characterize systems operating under high penetrations of renewable energy and storage. Correlations within the model capture linkage between load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge for energy-limited dispatchable resources such as hydro, energy storage, and call constraints for demand response. An overview of the RECAP modeling process is shown below in Figure 3-9.

Figure 3-9. Overview of RECAP Modeling Process



RECAP is used in several capacities throughout the analysis. First, it is used to generate the PRM necessary to meet the 0.1 days/yr LOLE target reliability standard. Then it is used to generate the ELCC values that quantify how non-firm resources such as wind, solar, and energy storage can contribute to the PRM. Both results are used as inputs into the RESOLVE portfolio optimization. The resulting portfolio from RESOLVE is then again tested in RECAP for a final check on reliability to ensure all resources are being accurately characterized as described in Figure 3-10.

Figure 3-10. Use of RECAP in the Analysis



Additional information regarding key assumptions and data sources utilized in the New England RECAP model are described in Appendix 7.4.

3.5.2 Effective Load Carrying Capability (ELCC)

RECAP is used to calculate effective load carrying capability (ELCC) values for non-firm resources as inputs into the portfolio optimization analysis. ELCC measures the ability of non-firm resources such as wind, solar, storage, hydro, and demand response to contribute to the PRM while still maintaining an equivalent level of system reliability. In other words, ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. A value of 50% means that the addition of 100 MW of a variable resource could displace the need for 50 MW of firm capacity without compromising reliability.

ELCC is calculated via the following steps:

1. Calculate base system (existing system) LOLE
2. Add renewable or storage resource(s) to the system and re-calculate LOLE
   + Due to the new resource(s), available generation in each hour is now greater than or equal to the base system which improves reliability (i.e. decreases LOLE)
3. Remove perfect capacity from the system until reliability returns to base system LOLE
   + Removing perfect capacity to the system reduces reliability (i.e. increases LOLE)

This process is illustrated in the figure below.

Figure 3-11. Overview of Methodological Steps to Calculate Resource ELCC

4.1 Economy-wide Decarbonization Pathways

Two pathways are utilized that meet an economy-wide net-zero emissions target, which this study modeled as 85% direct emissions reductions across New England, assuming remaining emissions are addressed by yet-to-be-commercialized direct abatement options, CDR, or offsets. The two scenarios, the High Electrification scenario and the High Fuels scenario, are designed to generate a bookend range of electricity resource adequacy requirements. While the two scenarios differ along several dimensions, both rely on four broadly aligned key decarbonization strategies or "pillars" (Figure 4-1). The scenarios assume significant energy efficiency across sectors, reducing energy use per household by roughly half. Both scenarios also increase electrification of end-uses while driving down fuel emissions intensity. While the High Electrification scenario relies more on electrification and the High Fuels scenario relies more on low-carbon fuels, both scenarios use both strategies to some degree. Finally, both scenarios assume the power sector achieves 95% clean generation by 2050.

Figure 4-1. New England Pillars of Decarbonization

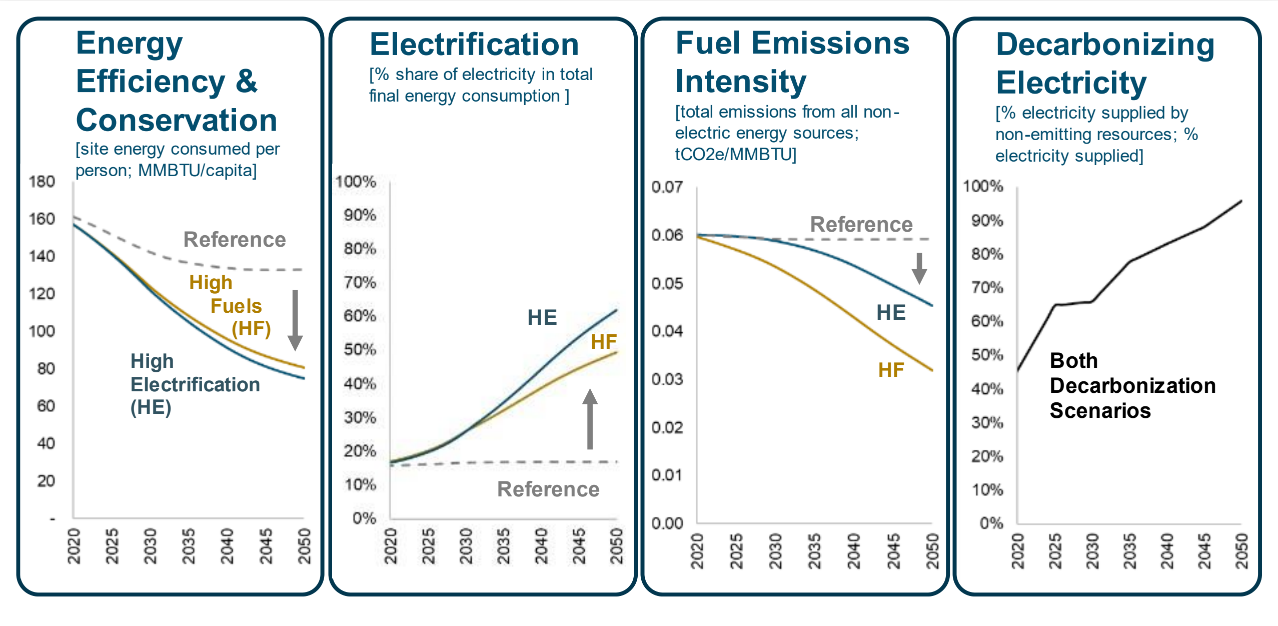


Figure 4-2 illustrates the emission reductions by sector, with final 2050 direct emissions shown on the right. The key differences in the remaining sector-specific emissions budgets between the two scenarios are based on assumptions regarding electrification. Because the electricity sector addresses more end uses and serves greater total load in the High Electrification scenario, this scenario has a slightly higher emissions budget compared to the High Fuels scenario, though both reflect about 95% carbon-free electricity.

In transportation, both scenarios assume significant penetration of battery electric vehicles, but the increased use of biofuels and hydrogen in the High Fuels scenario results in less generation and a lower emissions budget in the electricity sector than in the High Electrification scenario. In buildings, the High Electrification scenario assumes greater heat pump penetration, leading to a lower buildings emissions budget relative to the High Fuels scenario.

Figure 4-2. Reductions in Economy-wide GHG Emissions Reductions by Sector Through 2050

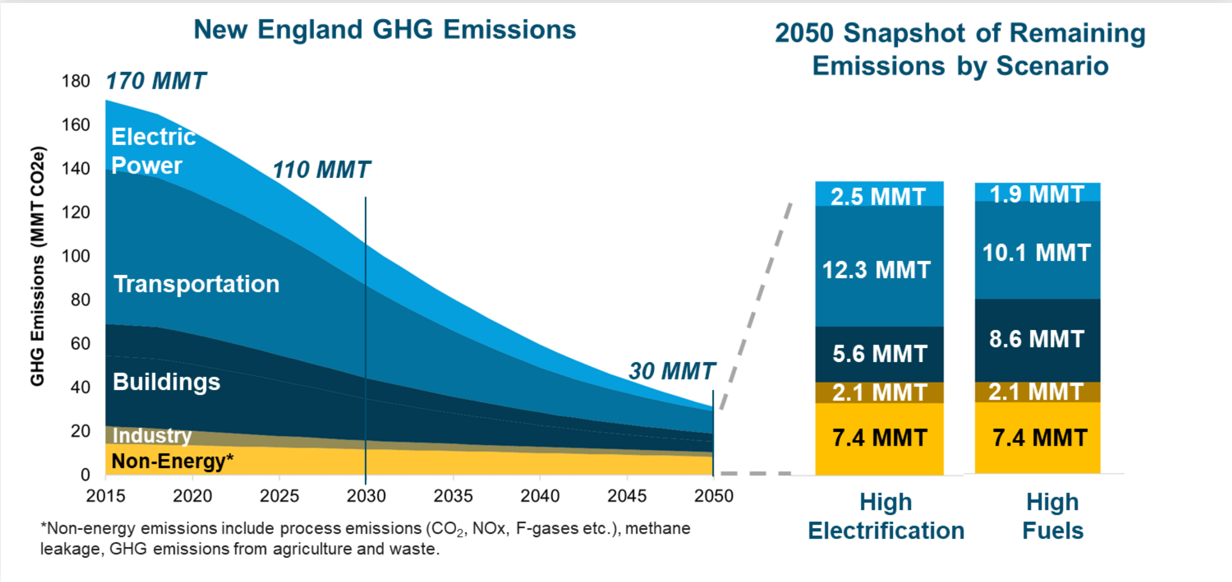


Table 4-1. Electricity Sector Emission Targets

	Electricity Sector Emission Targets (MMT CO_2e)					
	2025	2030	2035	2040	2045	2050
High Electrification	23.2	19.1	14.9	10.8	6.6	2.5
High Fuels	23.0	18.8	14.6	10.4	6.1	1.9

Growth in electric loads by sector and scenario is shown in Figure 4-3. Both scenarios see substantial amounts of energy efficiency mitigating the increase in electricity use from existing uses, but overall electricity use grows significantly due to electrification of end uses in transportation, buildings, and industry. The High Fuels scenario yields load growth of about 60% relative to 2020, while the High Electrification scenario yields load growth of about 90%.

Figure 4-3. Expected Load Growth by Scenario

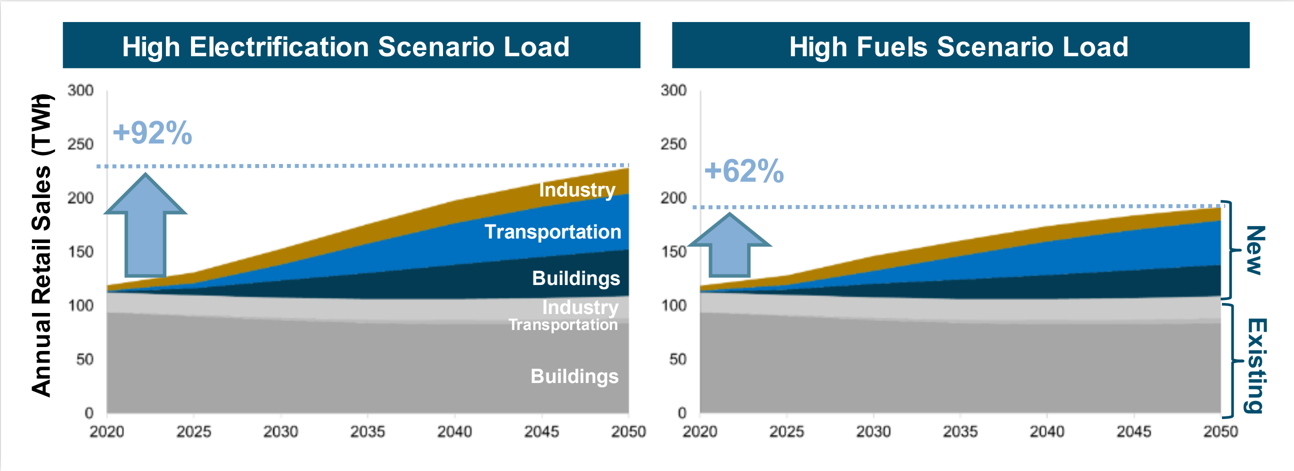


Table 4-5. Load Growth in High Electrification Scenario

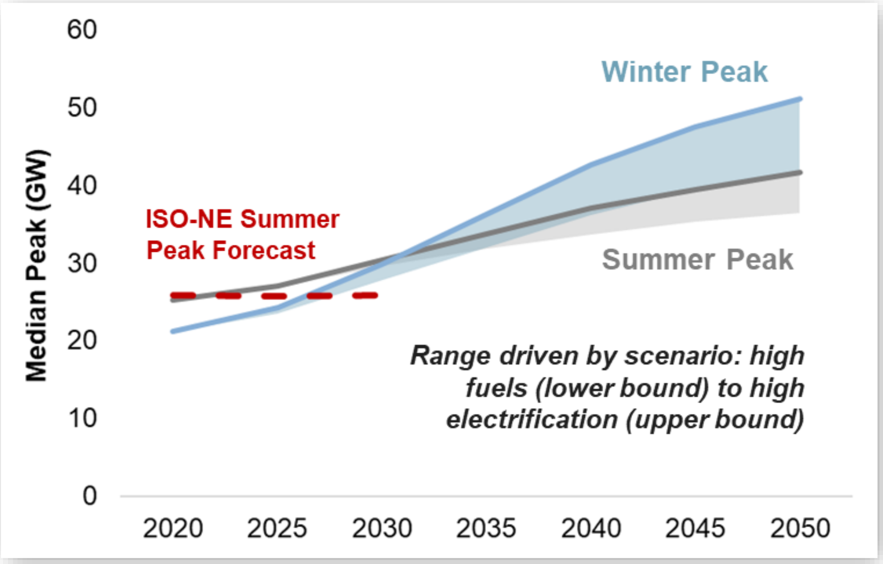
Year	Annual Retail Sales (TWh)					
	Existing Buildings	Existing Transportation	Existing Industry	New Buildings	New Transportation	New Industry
2020	94	1	18	1	1	5
2030	87	2	19	16	14	15
2040	83	4	20	32	39	21
2050	84	5	20	43	52	24

Table 4-6. Load Growth in High Fuels Scenario

Year	Annual Retail Sales (TWh)					
	Existing Buildings	Existing Transportation	Existing Industry	New Buildings	New Transportation	New Industry
2020	94	1	18	0	1	5
2030	87	2	19	13	12	14
2040	83	4	20	22	31	14
2050	84	5	20	29	41	12

These changes in annual electric load also cause significant changes in the peak load of both scenarios. Figure 4-4 shows median[o] gross peak load, net of energy efficiency, with the 2020 ISO-NE summer peak forecast for reference. Both scenarios have significant peak load growth as they transition from summer peaking to winter peaking in the 2030s. Electrification of space heating causes significant winter peak load increase, though our modeling includes a mix of heat pump technologies and some combustion-based systems to provide backup heat for electric space heating. Similarly, some transportation load contributes to peak, though our model includes significant load flexibility to reflect the potential for managed transportation charging or advanced vehicle to grid charging systems to help mitigate some of the coincident peak effects of transportation vehicle charging. More details related to our load shape development are available in Appendix 7.2.

Figure 4-4. Electric Peak Load Forecast



4.2 Electricity Generation Portfolios

RESOLVE develops cost optimal electric system resource portfolios to serve projected electric load and meet the electricity sector carbon caps defined in Section 4.1. Under both mitigation scenarios as well as the modeled sensitivities, wind and solar make up the majority of new capacity additions (see Figure 4-5). The model chooses a diverse mix of these resources – distributed solar, utility-scale solar, onshore wind, and offshore wind – given land constraints, transmission costs, and the economic and reliability value of having a geographically diverse set of resources.

In 2025, resource additions are driven by RPS targets and policy-driven distributed solar additions. The model assumes the New England Clean Energy Connect (NECEC) line from Canada to New England becomes

[o] Hourly load was simulated under 40 years of historic weather conditions from 1980-2019. The median annual peak across the 40 weather years is reported here. Details related to load shape development are available in Appendix 7.2.

operational with 1,200 MW nameplate capacity.[p] In subsequent years, new renewable capacity additions are driven by increasingly stringent carbon targets with renewable energy being the most economic option to meet those targets. Utility-scale solar is selected to serve local energy needs or fill up existing transmission headroom which does not incur more expensive 345 kV transmission upgrade costs.[q] Similarly, less expensive tranches of onshore and offshore wind that can utilize existing transmission headroom are also selected in earlier model years, with later builds requiring 345 kV transmission upgrades.[r] After the model exhausts the land-constrained, high quality, low transmission cost utility-scale renewable resources, distributed solar also plays a significant role. Finally, the model selects all available first-tier Quebec hydro (turbine upgrades) but does not select second-tier Quebec hydro (new impoundments) given the higher cost.

In addition to renewable resources, storage, nuclear, and gas provide both energy and capacity. Storage is primarily built with a four-hour duration which provides both energy arbitrage value as well as some incremental capacity value.[s] Notably, storage builds are somewhat smaller (relatively speaking) than regions with greater reliance on high quality solar, such as California; storage is a better complement to solar than the wind capacity that is more prevalent in New England due to the natural diurnal energy charge and discharge patterns. As existing nuclear licenses expire, replacement nuclear resources are selected up to an assumed constraint roughly equal to the total current size of the nuclear fleet (about 3.5 GW). While this is modeled as new advanced nuclear, it could reflect license extensions, repowering, or actual new builds. Finally, 3 to 10 GW of new natural gas capacity is built given its low costs and ability to provide firm, dispatchable capacity.

The resulting total portfolio of resources is shown in Figure 4-6. Total installed capacity in 2050 grows by about 80% in the High Fuels scenario, and about 130% in the High Electrification scenario, relative to the capacity in 2025. Most existing combustion-based resources are retained in the future to meet the region's capacity needs. This occurs because renewable resources and energy storage are only partly effective at meeting resource adequacy needs, and the portfolios therefore require additional backup capacity. Section 4.3 discusses the role of firm generation in developing a reliable electricity system in more detail.

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[p] All announced/planned fossil retirements are also incorporated (about 2,800 MW as of January 2020) but not shown in the figure. Nuclear units are assumed to retire at the end of existing licenses, but the model allows new nuclear builds – which could reflect license extensions, repowering, or actual new builds – but limits total nuclear capacity in the model to almost 3.5 GW, as discussed in the assumptions section.

[q] Note that all utility-scale renewable resource builds (solar, onshore wind, offshore wind) incur 230 kV interconnection costs.

[r] While evaluating the region's transmission requirements was not the primary focus of this study, it is clear that the region requires significant transmission builds. Overall, the model builds about 3,000 miles of 345 kV backbone transmission to integrate the region's renewables under the High Electrification scenario, assuming a single transmission line rating of 1,000 MW. Under a High Fuels scenario, the new transmission build is around half of that (1,500 miles). In both scenarios, about 600 miles of additional transmission is built to bring the hydro power (from less expensive turbine upgrades) from Quebec.

[s] Longer duration battery storage and other long-duration storage options remain too expensive to be valuable to the New England system.

Figure 4-5. Capacity Additions and Retirements

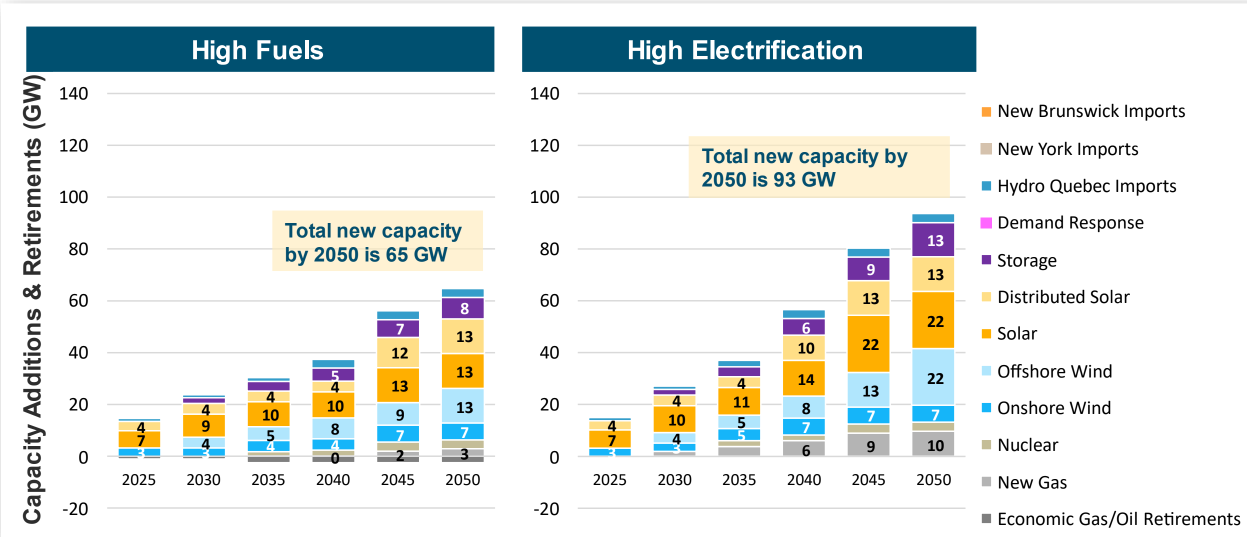


Figure 4-6. Total Resource Portfolio

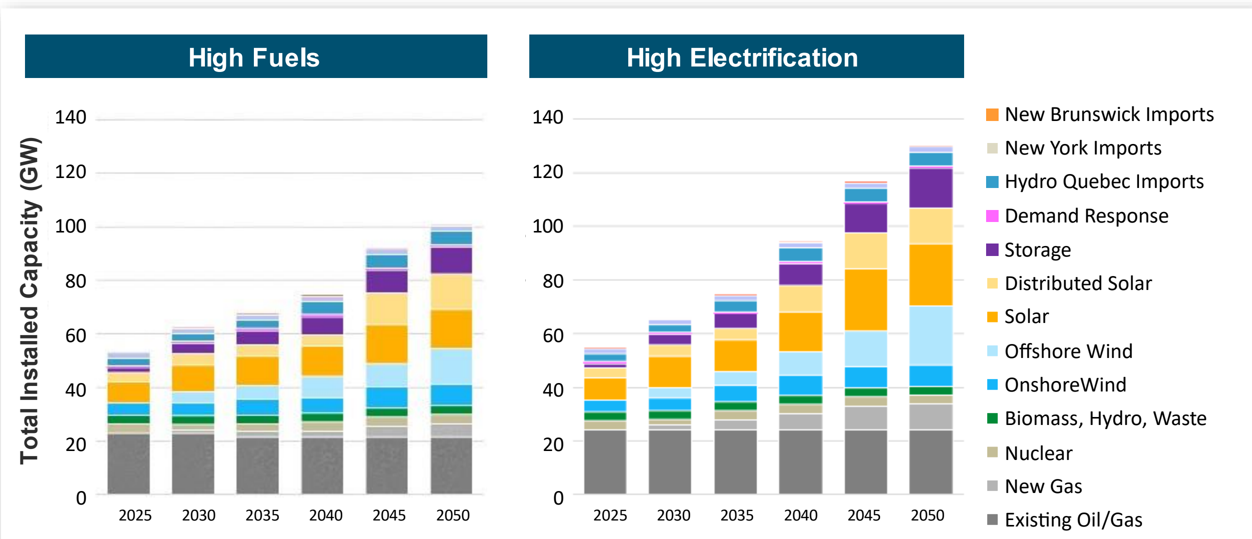
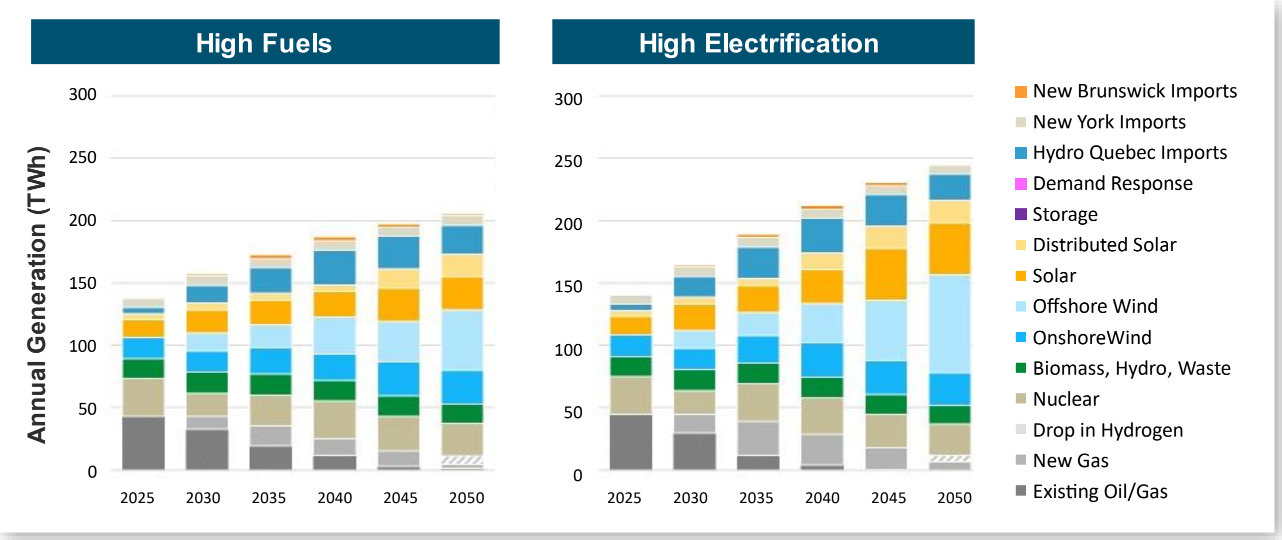


Figure 4-7 shows electricity generation by model year. By 2050, nearly all electricity generation is from zero-carbon resources, namely renewables, nuclear and imports (New York and Hydro Quebec). While combustion resources are retained for capacity, utilization of this fleet declines precipitously, and by 2050, these resources burn a mix of natural gas and hydrogen to meet emission targets.

Figure 4-7. Total Electricity Generation



4.3 Resource Adequacy Summary

4.3.1 Reliability in New England

The resource portfolios under both the High Electrification and High Fuels scenarios in 2050 are tested after the capacity expansion modeling to confirm they remain reliable. Using RECAP simulations, both portfolios were confirmed to be reliable, generating LOLE values less than 0.1 days/year.[t]

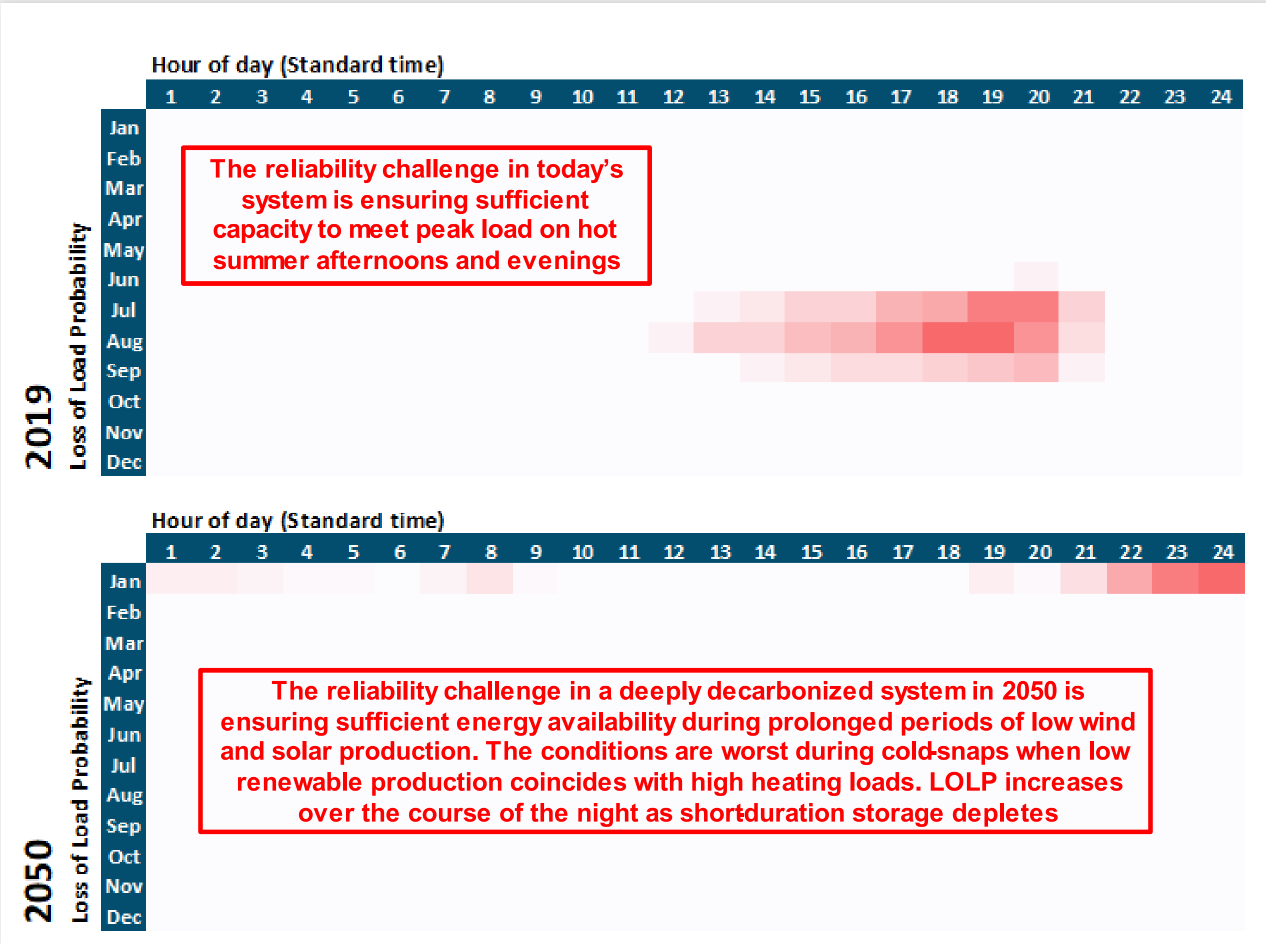
The nature of reliability challenges in 2050 is significantly different from current challenges. Because most existing generation capacity is dispatchable, the biggest reliability challenge is peak load events when there is the greatest probability that loads will exceed available generation. Presently, this typically occurs on hot summer afternoons (Figure 4-8). In the 2050 system where a significant amount of generation is variable or energy-limited, loss-of-load events do not necessarily occur in peak load hours but rather during extended periods where available generation is very low.

In the electricity system portfolios analyzed as part of this analysis, the biggest reliability challenge by 2050 is multi-day periods of low renewable energy production. When renewable energy production is low for only a short period of time (such as at summer nights when solar production is nil), existing energy storage technologies are capable of providing sufficient energy. However, when renewable production is low for a longer period of time (two or more days), limited-duration energy storage is insufficient to provide all required energy. Demand response resources can help mitigate the energy shortfall but

[t] The reliability target of 0.1 days/year for New England in 2050 translates to a target PRM of about 10.2% on an Unforced Capacity (UCAP) basis, which accounts for contributions from all resource types, including thermal, at their respective ELCCs. On an Installed Capacity (ICAP) basis, the target PRM is closer to 15%. The portfolios from both scenarios naturally satisfy the PRM requirement since the resulting LOLE is superior to the target.

practical limitations on magnitude and duration of response limit their contributions. For example, it would be unrealistic to expect a majority of buildings to reduce electricity use for heating during a prolonged cold snap. These prolonged periods of low renewable production are most likely to occur in winter when solar production is lowest, and at night when storage is most likely to become depleted (Figure 4-8).

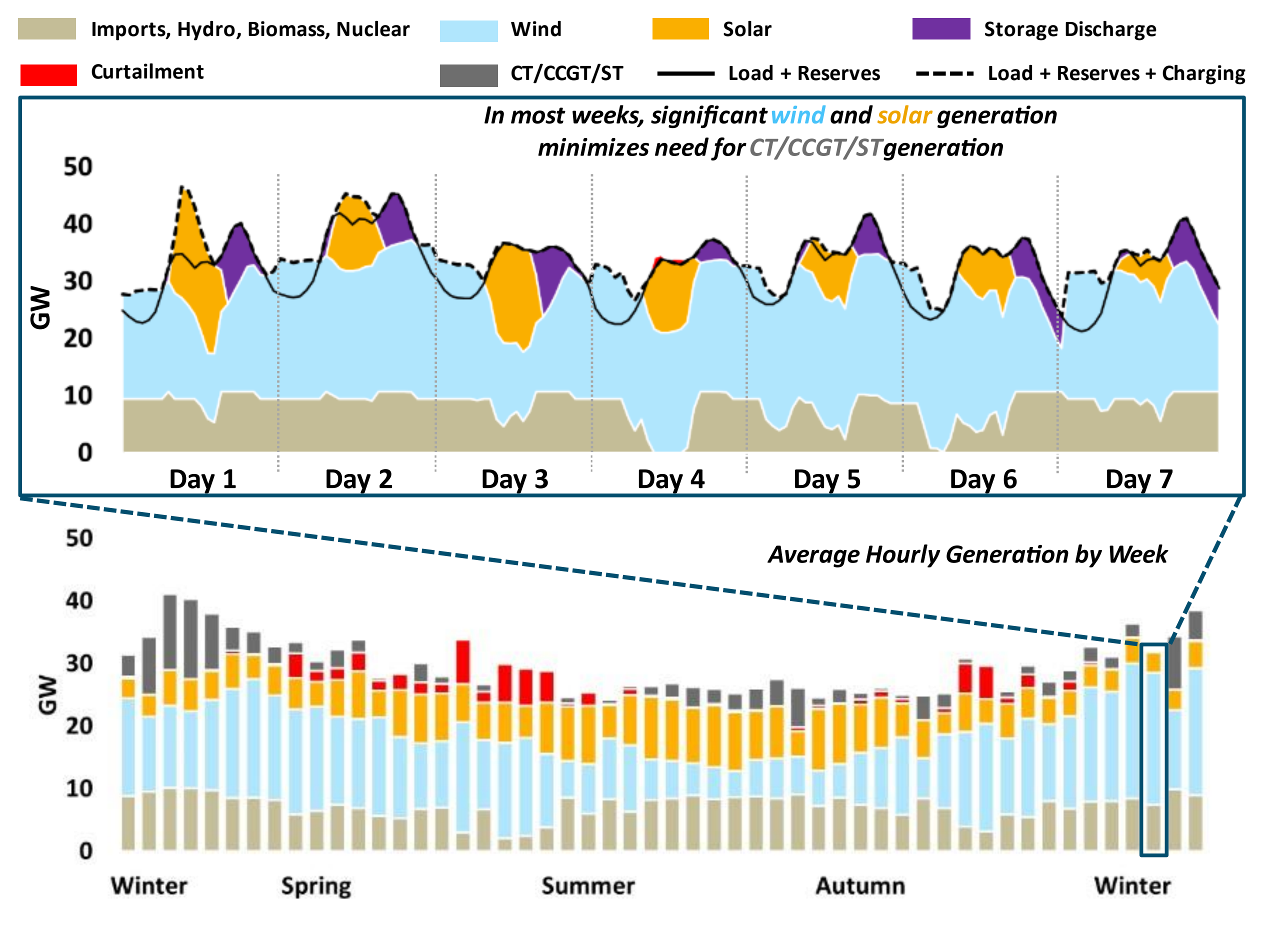
Figure 4-8. Loss-of-Load Probability Distribution by Month-Hour (High Electrification Scenario)



4.3.2 Role of Firm Generation

The portfolios developed in both the High Electrification and High Fuels scenarios contain a significant amount of new renewable capacity. In many weeks of the year when solar and wind are producing at average or above average output, the generation from these resources, in conjunction with the storage on the system, is sufficient to meet all energy needs as shown in Figure 4-9.

Figure 4-9. Illustrative Dispatch over a Typical Week in 2050[u] (High Electrification Scenario)



Note: CT/CCGT/ST could represent natural gas with or without CCS, hydrogen or other zero-carbon fuels burned in CT/CCGT, advanced nuclear or long duration storage.

However, during weeks with prolonged low solar and wind generation, it becomes necessary to dispatch firm resources as shown in Figure 4-10. As an example, the combined capacity factor of solar and wind generation is 6% in Day 5 of the sample week, leading to insufficient generation to either serve load or charge energy storage. Approximately one such equivalent day every year was identified in the historical solar and wind availability data sourced from NREL.[v] The additional solar, wind and storage that would need to be built to serve load in such instances would be significant and would also lead to significant renewable oversupply during average generation weeks. This outcome is shown in Figure 4-11.

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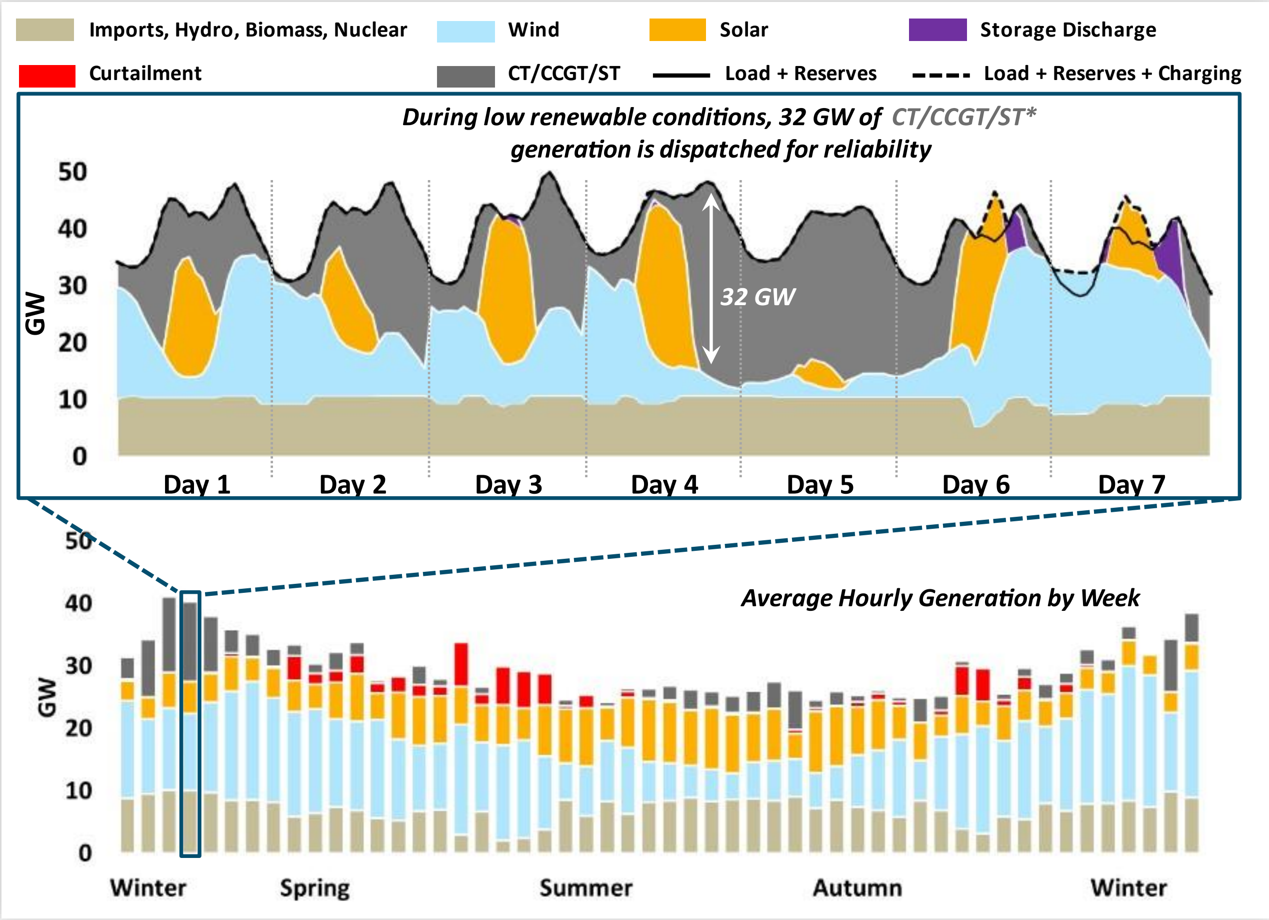
[u] The figure reflects one specific realization among several RECAP simulations of the year 2050 under different weather conditions, resource availability and outages.

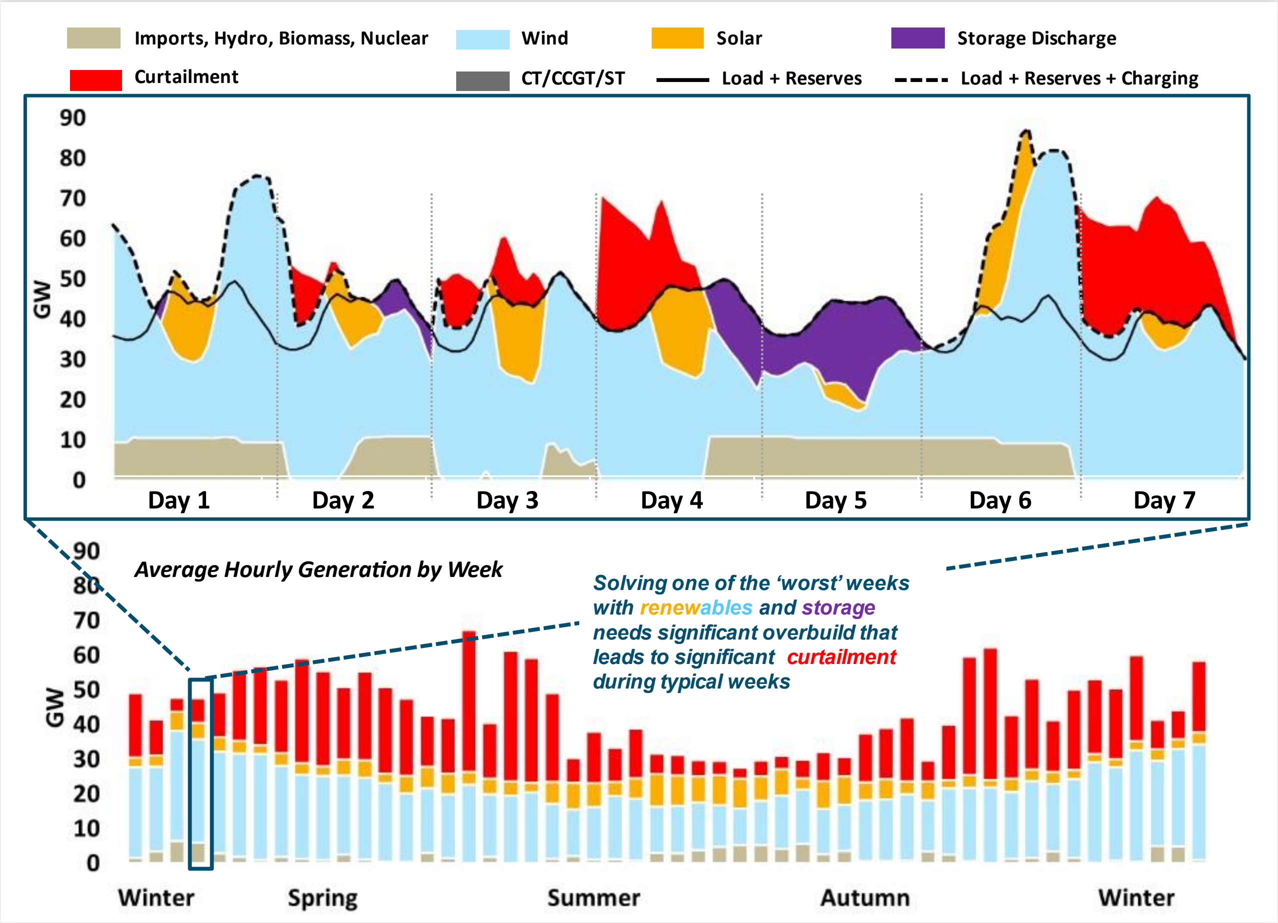
[v] Wind speed and solar insolation data were obtained from the NREL Wind Toolkit and the NREL Solar Prospector Database, respectively for 2007-2012. They were then transformed into hourly production profiles using the NREL System Advisor Model. Further details in Section 7.4.

Figure 4-10. Illustrative Dispatch over a Critical Week in 2050 (High Electrification Scenario)



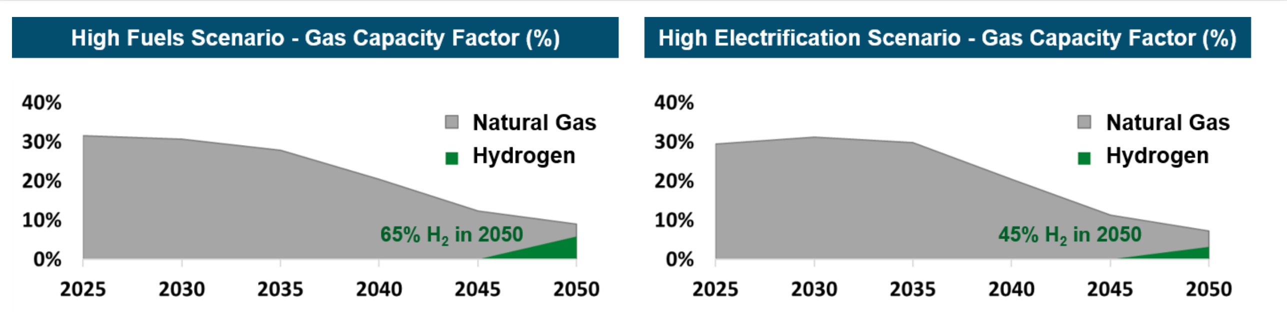
*Note: * CT/CCGT/ST could represent natural gas with or without CCS, hydrogen or other zero-carbon fuels burned in CT/CCGT, advanced nuclear or long duration storage.*

Figure 4-11. Illustrative Dispatch over a Critical Week in 2050 (No Combustion Resources with High Electrification Scenario)



Generation from natural gas combustion-based resources is relatively infrequent and, if based in part on carbon-free fuels, can still ensure compliance with stringent emission targets. As shown in Figure 4-12, the fleet-wide capacity factor of natural gas units reduces from about 30% in 2025 to 7-9% in 2050, with 45-65% of the fuel burned in 2050 being hydrogen, though this could be replaced with another zero-carbon drop-in fuel such as renewable natural gas. These combustion resources ensure that the system has sufficient firm capacity while meeting the electricity sector carbon target of 1.9-2.5 MMT/yr.

Figure 4-12. Gas Units (CC/CT) Capacity Factor Results



Taken together, a key finding of this study is that both retaining existing and building new natural gas capacity is consistent with deep decarbonization GHG targets as long as it is coupled with significant renewable resource additions, which provide the preponderance of energy generation.

4.3.3 ELCC Results

Effective load carrying capability (ELCC) is the quantity of "perfect capacity" that could be replaced or avoided with a resource while providing equivalent system reliability as described in Section 3.5.2. Figure 4-13 and Figure 4-14 show the ELCC provided by wind (offshore and onshore) and four-hour battery storage while also highlighting the significant diminishing marginal ELCC value at high penetrations of these resources. These diminishing returns for wind are due to saturation of production during high load hours and for battery storage are due to peak clipping that ultimately requires longer durations to continue to generate across all peak hours. These are well recognized phenomena within the industry.[w]

[w] See: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Figure 4-13. Wind ELCC in 2050 (High Electrification Scenario)

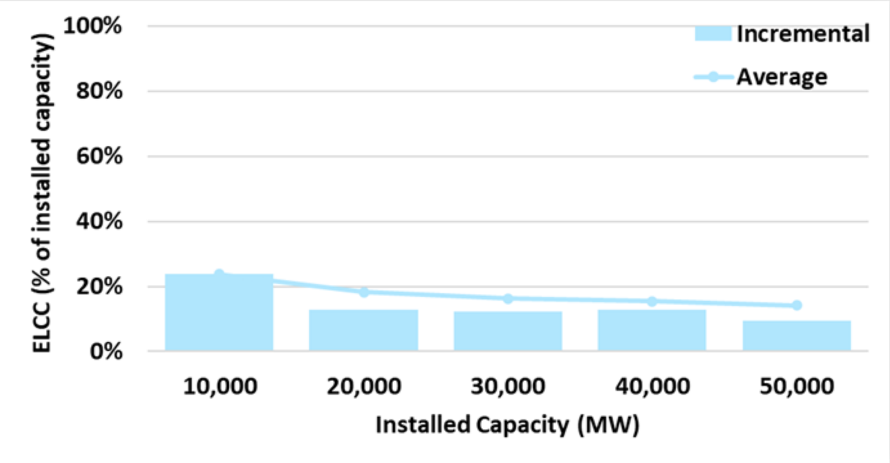
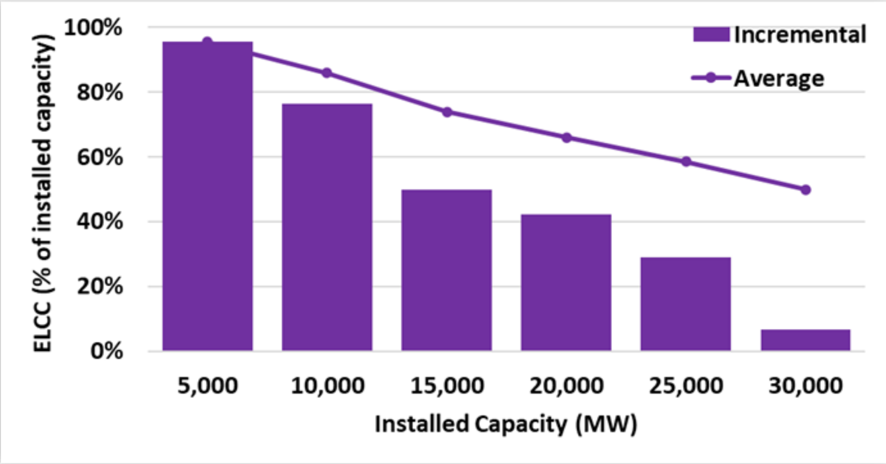
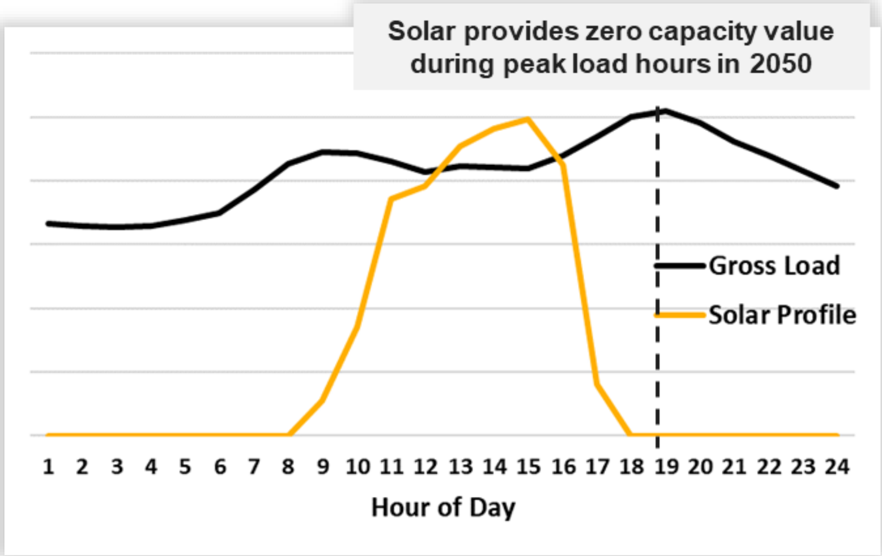


Figure 4-14. 4-hr Storage ELCC in 2050 (High Electrification Scenario)



In contrast, solar provides zero ELCC in 2050 due to its non-coincidence with peak load hours, as shown in Figure 4-15.

Figure 4-15. Non-Coincidence of Solar and Load in 2050



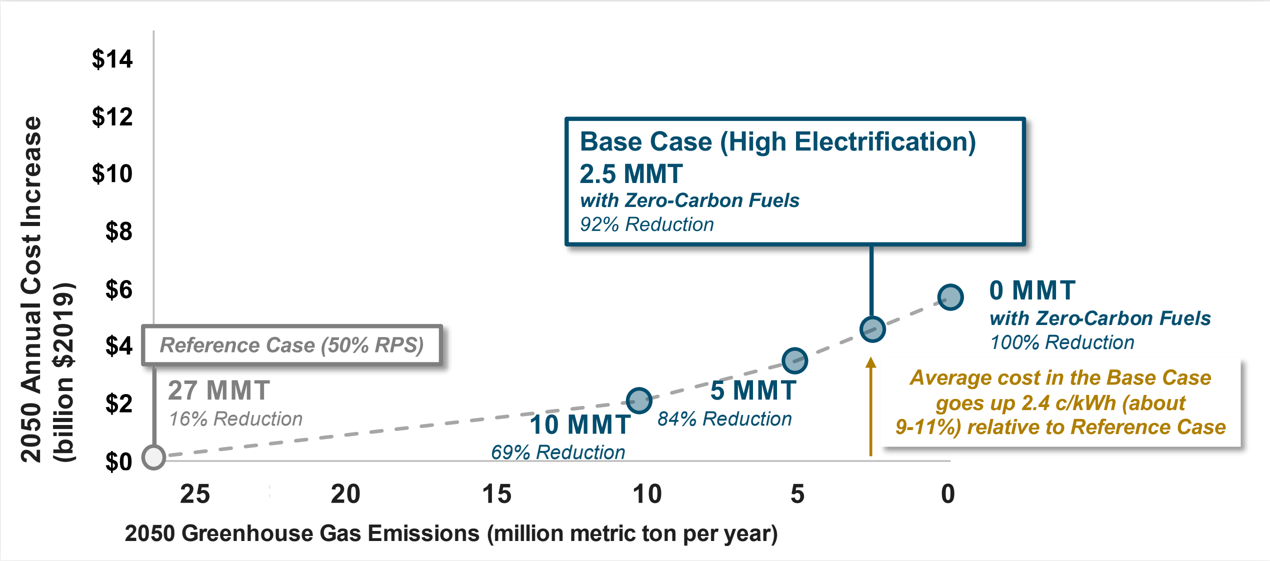
4.4 Electricity Sector Costs

This study calculates the cost to electricity consumers of the investments needed to meet increasing load and install sufficient clean energy generation capacity to achieve deep decarbonization targets.[x] RESOLVE minimizes the sum of generation-related new fixed costs and system operating costs. Fixed costs include investment in new generating resources and any associated transmission required to deliver clean energy to loads as well as fixed O&M costs. Fixed costs are reduced when existing resources are retired. Variable costs include fuel and variable O&M, which are reduced as incremental clean energy resources are added. Total costs in this study's scenarios increase over time, reflecting increasing load and investments in clean energy generation capacity and associated transmission.

While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is instructive to compare the total and average costs for each scenario to the Reference scenario and to each other to understand which factors are the largest drivers of ratepayer costs. Figure 4-16 shows the incremental cost of meeting increasingly stringent GHG targets, including the Base Case, relative to the Reference scenario, with numerical values provided in Table 4-7.

[x] The costs modeled in this study exclude other costs associated with economy-wide decarbonization that may be borne by the electricity sector, depending on future market, policy or regulatory structures. For example, this study excludes costs such as infrastructure and controls required to integrate distributed energy resources and vehicle charging; adding smart meters that are essential to implement time-of-use rates; and other auxiliary grid improvements to support a clean grid.

Figure 4-16. RESOLVE Modeled Costs Relative to Reference Case (High Electrification Loads)



*Notes: Cost increases are reported relative to a hypothetical Reference scenario that meets 50% RPS across New England. Emissions reductions are reported relative to a 2016 baseline of 32 MMT estimated based on EPA SIT database and import emissions. The average cost increase is calculated as the total increase in revenue requirement divided by assumed 2050 retail sales (including adjustments for losses and distributed PV). * The estimated average cost increase percentage includes an adjustment to RESOLVE modeled costs to reflect a proxy for non-modeled costs based on benchmarking to today's rates for non-modeled components. This proxy only affects the percent increase.*

Table 4-7. Key Electricity Sector Cost Results for Reference, Base, and Carbon Sensitivities (High Electrification)

Scenario	2050 Emissions (MMT)	Total 2050 RESOLVE Modeled Cost ($B/year)	Incremental 2050 Cost Relative to Reference ($B/year)	Average Cost Increase Relative to Reference (c/kWh)
Reference Case (50% RPS)	26.7	$20.7	--	--
Higher Carbon Target	10.0	$22.8	$2.1	1.2
Higher Carbon Target Case	5.0	$24.2	$3.5	1.8
Base Case	2.5	$25.3	$4.6	2.4
No Carbon Case	0.0	$26.4	$5.7	2.9

Notes: Total 2050 modeled costs include generation-related new fixed costs, associated new transmission costs, and total system operating costs. Increases are reported relative to Reference Case of 50% RPS. The average cost increase reflects the increase in total revenue requirement adjusted for sales (including adjustments for losses and distributed PV).

4.5 Sensitivity Results

The cost-optimal resource portfolio to achieve a deeply decarbonized GHG electricity system is affected by the available supply of existing clean energy technologies and the extent to which new and emerging technologies become commercially available over time. The sensitivity analysis conducted for the study analyzes both of these aspects by varying the land area available for onshore renewables and in some cases allowing new firm capacity candidate resources such as advanced nuclear and natural gas power plants with 90% carbon capture rate. All sensitivity analyses were conducted on the High Electrification scenario and listed in Table 4-8. Additionally, the study investigated the implications of disallowing new combustion-based resources and retiring all existing combustion-based resources. These are included in the table but evaluated in more detail in Section 4.6, which focuses on the role of firm capacity.

Table 4-8. Overview of Sensitivity Assumptions

Category	Sensitivity	Description
Land Area for Onshore Renewables	Land Constrained	Solar and onshore wind resource potential is limited to 50% of the base case
	Land Unconstrained	Solar and onshore wind resource potential is limited to the NREL technical potential (no land constraints imposed)
Firm Capacity Resources	Unlimited Advanced Nuclear	No limit on advanced nuclear build (Base Case is limited to 3.5 GW)
	Natural Gas with Carbon Capture & Sequestration	Gas turbine units (peakers and combined cycle) that capture 90% carbon emissions available for selection
	Advanced Nuclear + Natural Gas with Carbon Capture & Sequestration	Both advanced nuclear and natural gas with CCS are available for selection without limit
Combustion Generation (Section 4.6 Only)	No New Combustion Generation	No new combustion generation is allowed
	No Combustion Generation	No new combustion generation is allowed and all existing combustion generation is retired

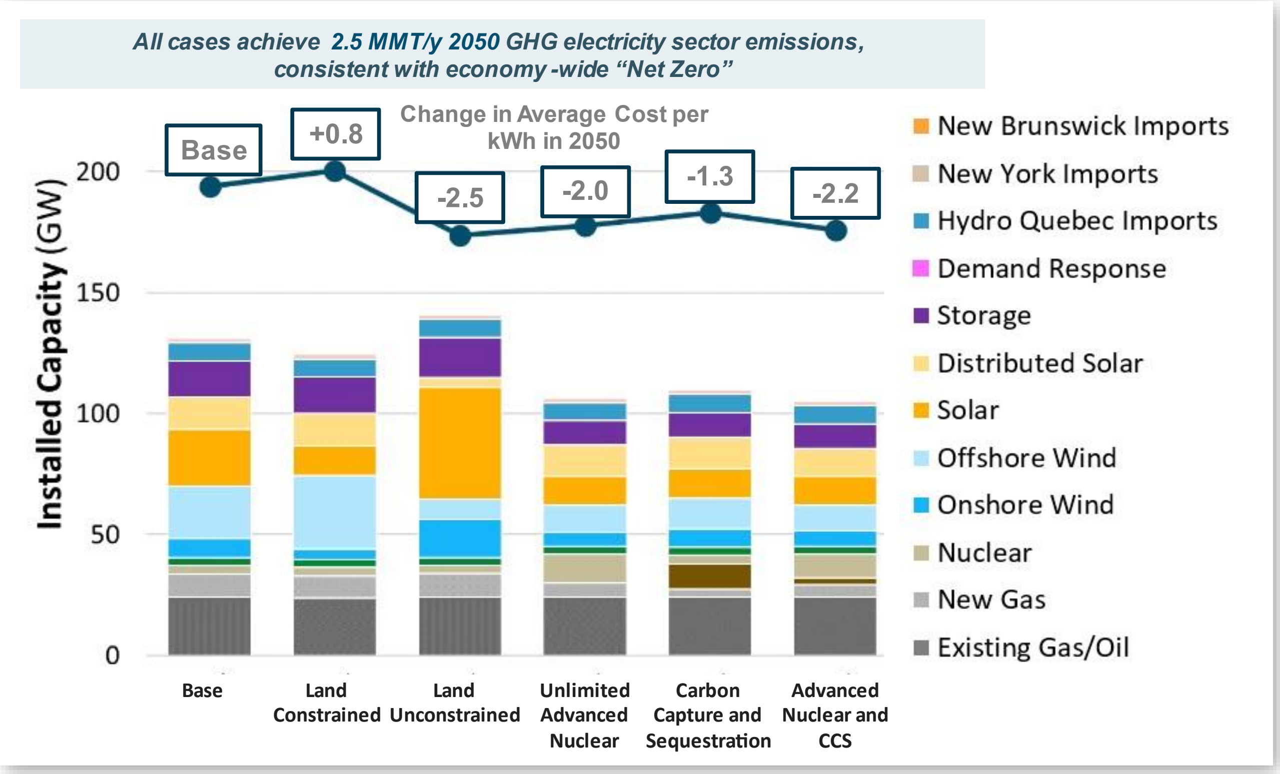
Figure 4-17 shows the total installed capacity in 2050 for the resource sensitivities alongside the Base Case High Electrification scenario portfolio. Each of the portfolios shown achieves the electric sector goal of 2.5 MMT CO_2e emissions by 2050. When onshore wind and solar are limited ('Land Constrained' sensitivity), more offshore wind is built but other firm generation is unchanged. When onshore wind and solar land constraints are removed ('Land Unconstrained' sensitivity), more of these resources are built with less offshore wind.[y]

When emerging firm generation capacity technologies (advanced nuclear and natural gas with 90% carbon capture rate) are available, they are selected in significant quantities. These technologies not only provide clean generation but are also available on a dependable and consistent basis and do not suffer from multi-

[y] In particular, only the portion of offshore wind that can be integrated on the system given existing transmission headroom is selected in this sensitivity.

day periods of low generation as wind and solar do. The total GW of installed capacity for these sensitivities is lower than in cases without these technologies because of their higher "effective capacity" relative to renewables and storage.

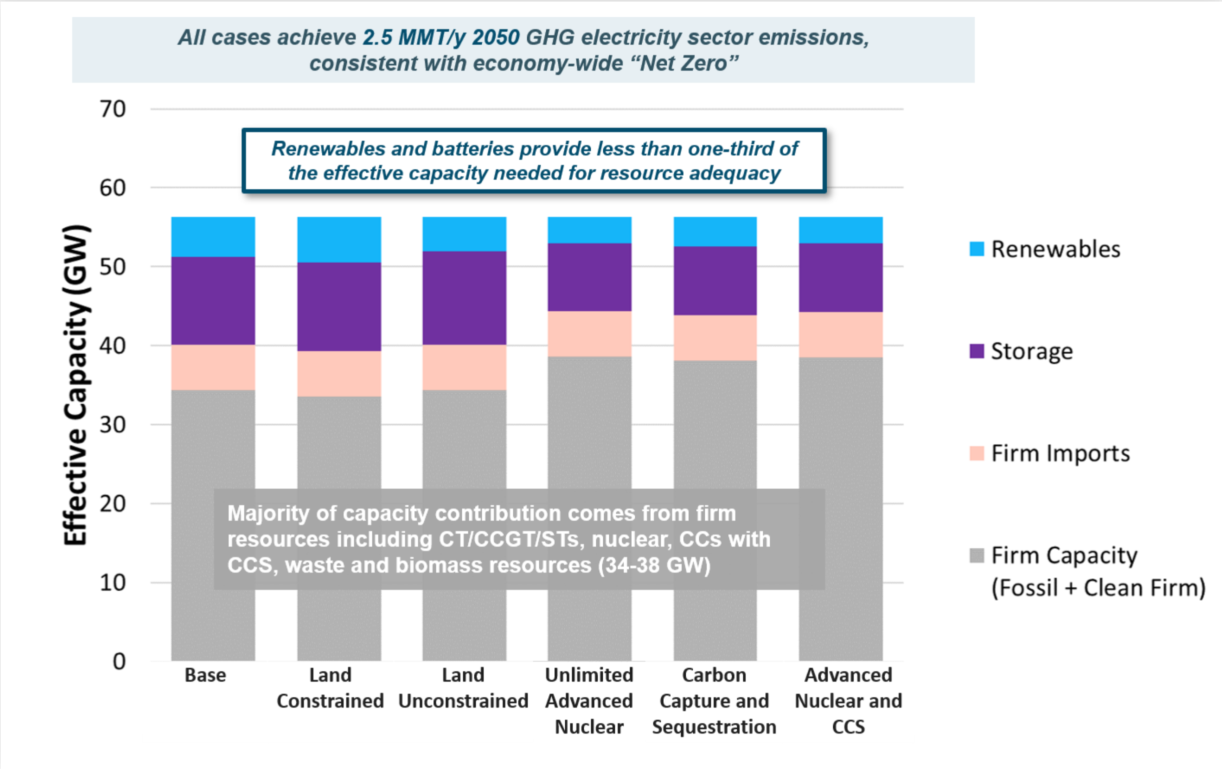
Figure 4-17. Sensitivity Results: Total Installed Capacity in 2050



Note: Average costs per kWh are compared to the Base Case estimated 2050 average cost of about 23.3-27.3 cents/kWh, which includes RESOLVE modeled costs plus a range of estimated non-modeled costs (proxy for non-modeled costs is based on benchmarking to today's rates and held constant across cases, thus does not affect deltas).

A resource's effective capacity is a measure of its contribution to the system's planning reserve margin requirement. The effective capacity of firm resources is measured using their 'unforced' capacity (UCAP), i.e capacity after simulation of forced outages, while the effective capacity of renewable energy and storage is measured using ELCC. Figure 4-18 shows that the majority of effective capacity in all scenarios comes from firm resources. Renewables and energy storage provide only about 12 to 17 GW of the system's effective capacity across the scenarios, despite nameplate capacity ratings of about 50 to 90 GW. The availability of clean firm resources like advanced nuclear and natural gas with carbon capture result in an even greater capacity contribution from firm resources.

Figure 4-18. Sensitivity Results: Effective Capacity in 2050



4.6 Effects of Limiting Natural Gas Capacity or Availability of Emerging Technologies

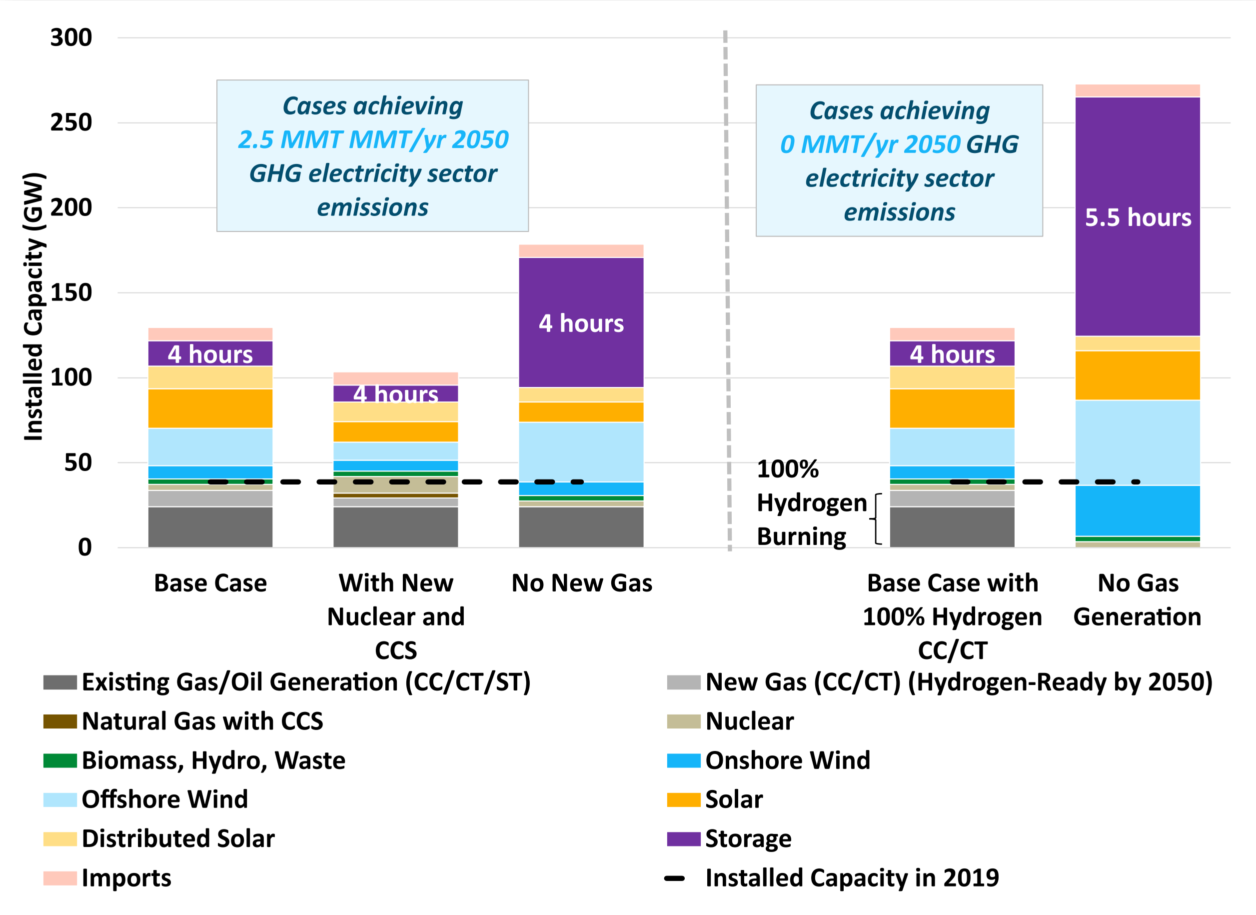
This study focuses on electricity sector reliability and the role of firm generation technologies under economy-wide net-zero emissions. Today, natural gas capacity (CTs and CCGTs) provides the most cost-effective source of firm capacity due to very low capital costs. A key finding of this study is that up to 10 GW of new natural gas generation may be needed in New England, even under scenarios in which CO_2 emissions are reduced to 2.5 MMT, in order to ensure reliability during extended periods of time in which wind and solar energy are not available. This is especially true under the High Electrification scenario, in which peak electricity demand increases to 51 GW by 2050 largely due to increased heating loads.

Nuclear also provides firm, zero-carbon capacity, but existing nuclear licenses will expire over the next 25 years and the cost declines and commercialization of advanced nuclear remains uncertain. Moreover, there are also siting and safety challenges to building new nuclear. As a result, our Base Case assumes total nuclear capacity cannot exceed 3.5 GW, reflecting either relicensing, repowering, or new builds at the same site; no additional new nuclear can be selected.

Figure 4-19 demonstrates how the 2050 resource portfolio would change under three sensitivities related to the availability of firm generation and the GHG emissions budget: 1) if advanced nuclear and carbon capture & sequestration technologies become available in the region; 2) if no new gas generating capacity is allowed; or 3) if all new and existing combustion-based (CCGT/CT/ST) capacity is forced to retire. Note that in the third sensitivity, the electricity system emissions would by design fall to zero, given the lack of any remaining fossil generation. For this reason, we also model a zero-carbon version of the Base Case, with combustion generation capacity available that can burn hydrogen (or other zero-carbon fuel) in 2050, to provide a relevant comparison.

If combustion technologies are limited or retired, replacing this capacity with additional intermittent renewables and storage requires overbuilding to ensure sufficiency during prolonged periods of low renewable generation. Overbuilding renewables entails significant renewable curtailment under normal conditions, while significantly increasing storage duration is prohibitively expensive given commercially available storage technology. As Figure 4-19 shows, eliminating combustion in New England would require 51 GW of renewables and 126 GW (710 GWh) of energy storage *incremental* to that in the Base Case.

Figure 4-19. Sensitivity Results Limiting/Expanding Firm Capacity Options: Total Installed Capacity in 2050 (High Electrification Scenario)



Notes: In the 0 MMT Base Case, all existing and new gas units, when dispatched, burn 100% hydrogen in 2050. In the 2.5 MMT model runs, hydrogen is available as a drop-in fuel and blended in at varying percentages with natural gas in order to meet the 2.5 MMT electricity sector target in 2050 only. The existing fossil capacity includes units burning natural gas, oil or coal today in combustion turbines (CT), combined cycles (CC) or steam turbines (ST), but only natural gas and hydrogen are burned by 2050. Annotations for storage represent average duration across the total installed capacity.

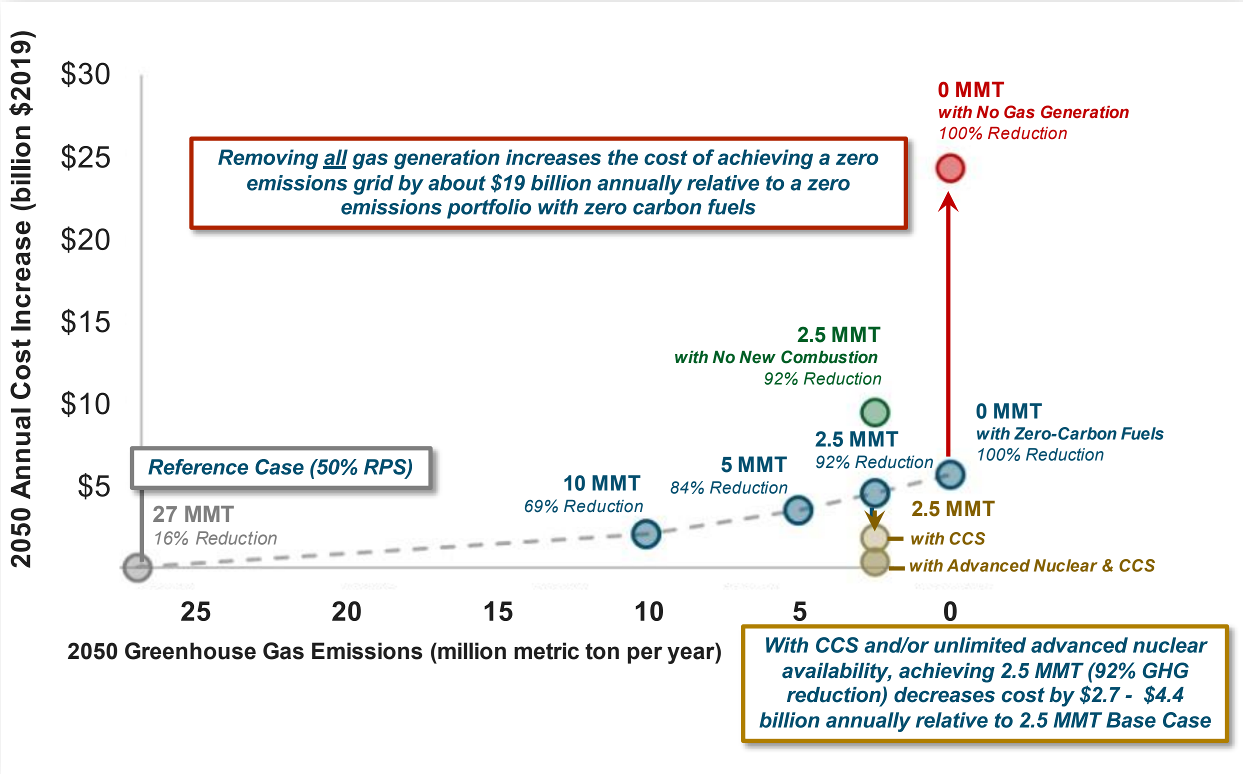
In Figure 4-20, we report the annual electricity costs and emissions reductions for these sensitivities, relative to a Reference Case.[z] The figure highlights the role of firm combustion-based capacity (CTs and CCGTs) in reducing the cost of decarbonization. When new combustion capacity is not allowed (shown in green), the incremental cost to achieve 2.5 MMT/yr more than doubles relative to a scenario in which new gas generation is allowed, to nearly $10 billion per year relative to a Reference (50% RPS) case. If all new and existing combustion capacity is retired (shown in red), the incremental cost of fully decarbonizing the

[z] The grey line shows how at deeper levels of decarbonization, the electricity sector costs increase steadily, reflecting the increasing challenge of decarbonization. The average cost of abatement ($/ton) is in Figure 4-21, and the associated $/ton marginal costs of GHG abatement are provided in Appendix Figure 7-18.

electricity sector is $24 billion/yr more than the Reference Case, more than four times higher than a scenario in which combustion of zero-carbon fuels is allowed. In Figure 4-21, we also provide the average cost of carbon abatement for these cases. The grey curve reflects our base set of assumptions under High Electrification loads, in which zero-carbon fuel (hydrogen) is available, while the green and red dots reflect the cases with no new combustion, and no new and existing combustion-based generation allowed.[aa]

While clean firm technologies are largely unproven at scale today, they offer a potential cost-effective approach to maintain reliability under deep decarbonization. Annual incremental cost to achieve 92% reduction in emissions under High Electrification scenario is cut by more than half when CCS technology is assumed to be developed at scale. When advanced nuclear is available at scale, the cost of decarbonization declines significantly (about $4.2 billion/year less relative to Base), and it falls even more when combined with CCS (about $4.4 billion/year less relative to Base).

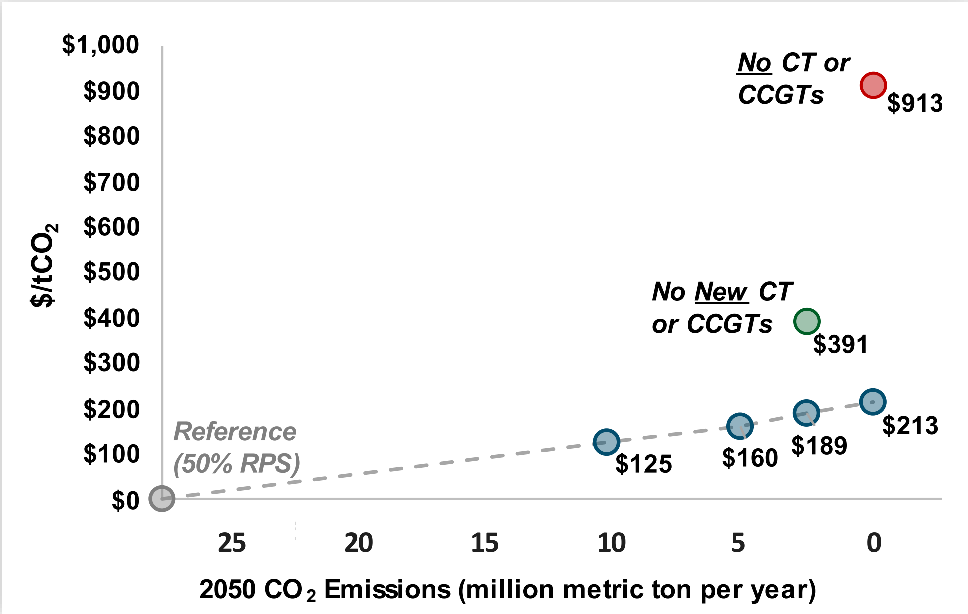
Figure 4-20. Increase in Electricity System Modeled Costs Relative to Reference Case, Including Limited/Expanded Firm Capacity Options Across Selected Set of Scenarios in 2050 (High Electrification)



Notes: Cost increases are reported relative to the hypothetical Reference Case (50% RPS), which has annual costs in 2050 of $20.7 billion. Emissions reductions relative to 2016 emissions of 32 MMT estimated based on EPA SIT database and import emissions for all New England States. The "No Gas Generation" Case removes all fossil and hydrogen/zero-carbon fuel generation (CC/CT/ST) from the portfolio.

[aa] Marginal costs of carbon abatement are provided in Appendix Section 7.6.

Figure 4-21. Average Cost of Carbon Abatement (High Electrification Loads)



The values above reflect the average costs of carbon abatement relative to the Reference Case (50% RPS).

4.7 Environmental Justice Implications of the Modeling Results

The rapid transformation of the energy economy has the potential for adverse equity and environmental justice impacts unless explicit policies are developed. The costs brought on by the electricity sector transformation and widespread technological change in end-use sectors envisioned by this report are material and will be more difficult to bear for low-income households, who already spend a higher-than-average proportion of income on energy and transportation. The region must pursue strategies that lower the expected costs of decarbonizing the power system, in part by making as many low-carbon firm generating technologies available by mid-century—through implementing policies like the Massachusetts clean energy standard, for example—and relying on existing energy infrastructure where compatible with long-term emissions reduction goals.

Cost recovery for legacy energy infrastructure can also create financial pressure on vulnerable populations. For example, those who are unable to afford heat pumps could be left paying for legacy infrastructure systems (e.g., natural gas distribution or heating oil delivery) the costs of which must be recovered from ever fewer customers, thereby driving up costs of delivered energy. Careful attention must be paid to managing the direct consumer costs of these energy infrastructure transitions.

Historically, emissions-generating infrastructure (e.g., power plants, industrial plants, major highways) has been disproportionately located in areas with high numbers of low-income and minority households. The modeling results suggest a continued critical role for existing fossil-fuel power plants, albeit operating at significantly lower capacity factors. The region must manage the impacts of past, present, and future power plant development to ensure an equitable and just energy transition. On a positive note, given the disproportionate impact of transportation on current local air quality, electrification of transportation as part of a comprehensive decarbonization strategy provides a unique opportunity to improve local air quality in low-income and minority communities.

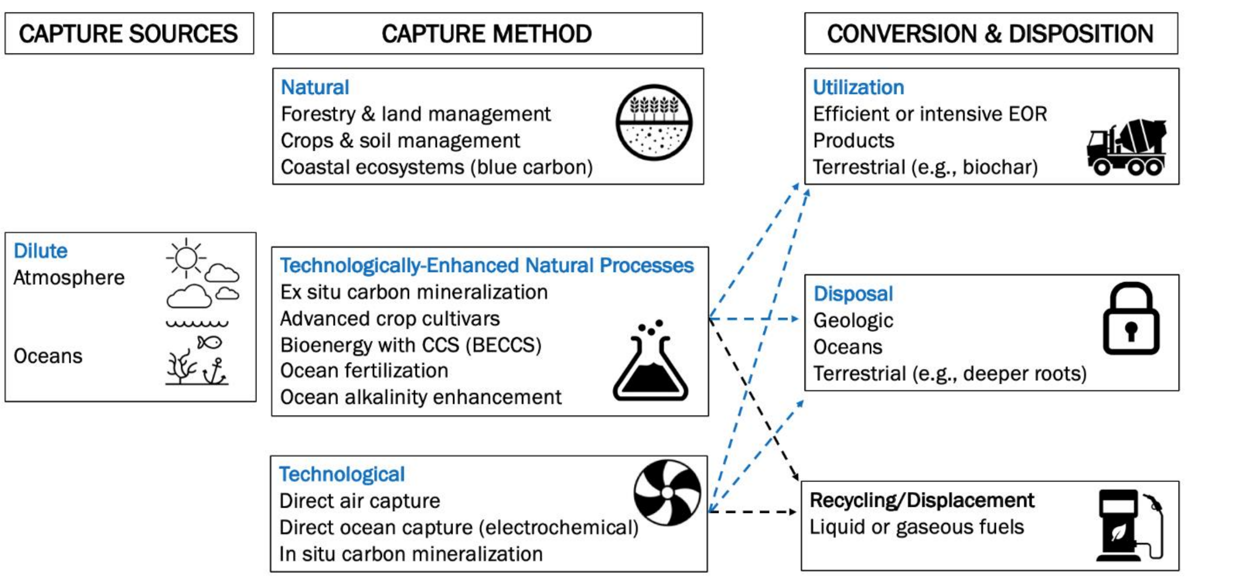
5.1 The Net-Zero Challenge

The economy-wide modeling in this study achieves 85% direct emission reductions. This reflects the assumption that certain subsectors of the economy will be difficult to decarbonize with current technology. This section explores two options for closing the gap to net-zero—carbon dioxide removal and technological innovation—and evaluates how these solutions can harness the region's existing strengths.

5.2 Carbon Dioxide Removal Potential in New England

Carbon dioxide removal (CDR) is a nascent yet rapidly emerging field that can help achieve GHG emissions reduction goals and will be especially important in the pursuit of net-zero climate targets. Although deep and sustained economy-wide mitigation efforts are the most cost-effective way to provide the vast majority of GHG reductions, it is highly likely that there will be residual emissions that prove extremely difficult and expensive to eliminate. The full suite of CDR opportunities could thus serve as a vital complement to mitigation efforts by compensating for residual emissions and, coupled with a dedicated clean energy innovation agenda more broadly—allow society to approach net-zero emissions by midcentury (Figure 5-1).

Figure 5-1. Opportunities for Carbon Dioxide Removal



There are a variety of natural, technologically enhanced natural processes, and technological approaches that can facilitate CDR.

To date, few attempts have been made to investigate region-specific applications of CDR technologies in the United States across the entire realm of options. This study uses a new analysis framework to identify the CDR approaches and potential for a given region. This framework draws on previous, including the report *Clearing the Air: A Federal RD&D Initiative and Management Plan for Carbon Dioxide Removal Technologies*,[42] as well as research done by other organizations, especially *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda,*[43] a report by the National Academies of Science, Engineering, and Medicine (NASEM). The framework has two steps:

- Narrowing the list of CDR approaches based on region-specific conditions, and;
- Evaluating the potential impact of those CDR approaches, as measured in annual negative GHG emissions.

There is a high degree of uncertainty regarding the costs and abatement potential of large-scale CDR deployment, and dimensions of CDR pathways, such as the monitoring, reporting, and verification, that require further development and standardization. As such, all estimates are presented as ranges to reflect this uncertainty. Technical, policy, and business model innovations have the potential to change the dynamics of CDR substantially, creating even greater opportunity on longer timescales.

5.2.1 CDR Suitability Analysis

The first step of this analysis framework involves identifying the most suitable CDR approaches for New England from across the spectrum of natural, technologically enhanced natural, and purely technological options. The framework considers general and region-specific factors such as the degree of technological readiness, permanence risks, geographic and land use needs, infrastructure needs, disposition potential, energy needs, and political concerns and compatibility. This suitability analysis is conducted with an eye toward multiple time scales, with the assumption that deployment readiness for all approaches will advance over time.

Among the spectrum of CDR approaches evaluated for suitability in the context of New England, several natural CDR approaches are the most imminently applicable:

- **Agricultural soil carbon.** This analysis focuses on a subset of approaches that increase the soil carbon in agricultural lands: no-till farming (which increases carbon storage by slowing the decay of organic matter) and organic soil amendments (which improve soil attributes and nutrient availability). Other soil carbon practices with near-term deployment suitability include the use of cover crops and grazing land management.
- **Reforestation/afforestation.** Reforestation and afforestation involve planting or facilitating the growth of trees in areas that have been in nonforest use, which increases both organic carbon and soil carbon stores.
- **Forest management.** Improved forest management practices for CDR generally aim to increase tree growth or preserve trees in already forested areas. The forest management approach includes accelerating regeneration in areas with disturbances, extending harvest rotations,

treating/preventing outbreaks of pests or diseases, and preventing unsustainable conditions by thinning or reintroducing endemic species.

+ **Coastal blue carbon**. Coastal blue carbon approaches involve the preservation, restoration, and expansion of coastal ecosystems, especially seagrass meadows, salt marshes, and (in other regions) mangrove forests. These ecosystems have a high rate of soil organic carbon storage and provide ancillary ecological and economic benefits.

The full results of this analysis can be found in Table 5-1. These natural approaches have low deployment costs, require little new infrastructure, and (with forestry approaches in particular) harness New England's existing strengths.

Table 5-1. Results of CDR Approach Suitability Analysis for New England

Category	Approach	2020–2030 Suitability	2030–2040 Suitability	2040–2050 Suitability
Natural	Afforestation/reforestation	High	High	High
	Blue carbon	High	High	High
	Engineered wood products	Moderate	High	High
	Forestry management	High	High	High
	Agricultural soil carbon	High	High	High
	Macroalgae cultivation	Moderate	Moderate	Moderate
Technologically Enhanced	Advanced crop cultivars	Low	Moderate	High
	Advanced landfilling	Moderate	High	High
	BECCS (fuels)	Moderate	Moderate	Moderate
	BECCS (electricity)	Moderate	Moderate	Moderate
	Biochar amendment	Low	Moderate	High
	Deep soil inversion	Low	Moderate	High
	Ex situ carbon mineralization	Moderate	Moderate	High
	Green-tree burial	Moderate	High	High
	Ocean alkalinity enhancement	Low	Low	Moderate
	Ocean iron fertilization	Low	Low	Moderate
Technological	Direct air capture	Low	Moderate	Moderate
	Direct ocean capture	Low	Low	Moderate
	In situ mineralization	Low	Moderate	High

In the context of longer-term emissions reduction goals, the majority of technologically enhanced and purely technological approaches will require further public and private investment to move closer to commercial readiness. Several of those approaches, however, will nonetheless face challenges in New England due to the lack of suitable geology for large-scale disposition (e.g., saline formations or oil and gas deposits). An expansive buildout of CO_2 pipeline infrastructure to suitable geologic sequestration locations is highly uncertain, would be very costly, and could take years or decades to fully deploy—presenting a challenge to both CDR and power plant or industrial carbon capture. While offshore geologic sequestration has been demonstrated elsewhere in the world, it has not been conducted in the United States and would pose a host of technical and regulatory challenges.

5.2.2 Deployment Potential Analysis for Natural CDR Approaches

The second step in the CDR evaluation framework blends top-down and bottom-up methods for estimating carbon removal potential (measured in mass of CO_2 removed annually) of the viable approaches identified in the suitability analysis.

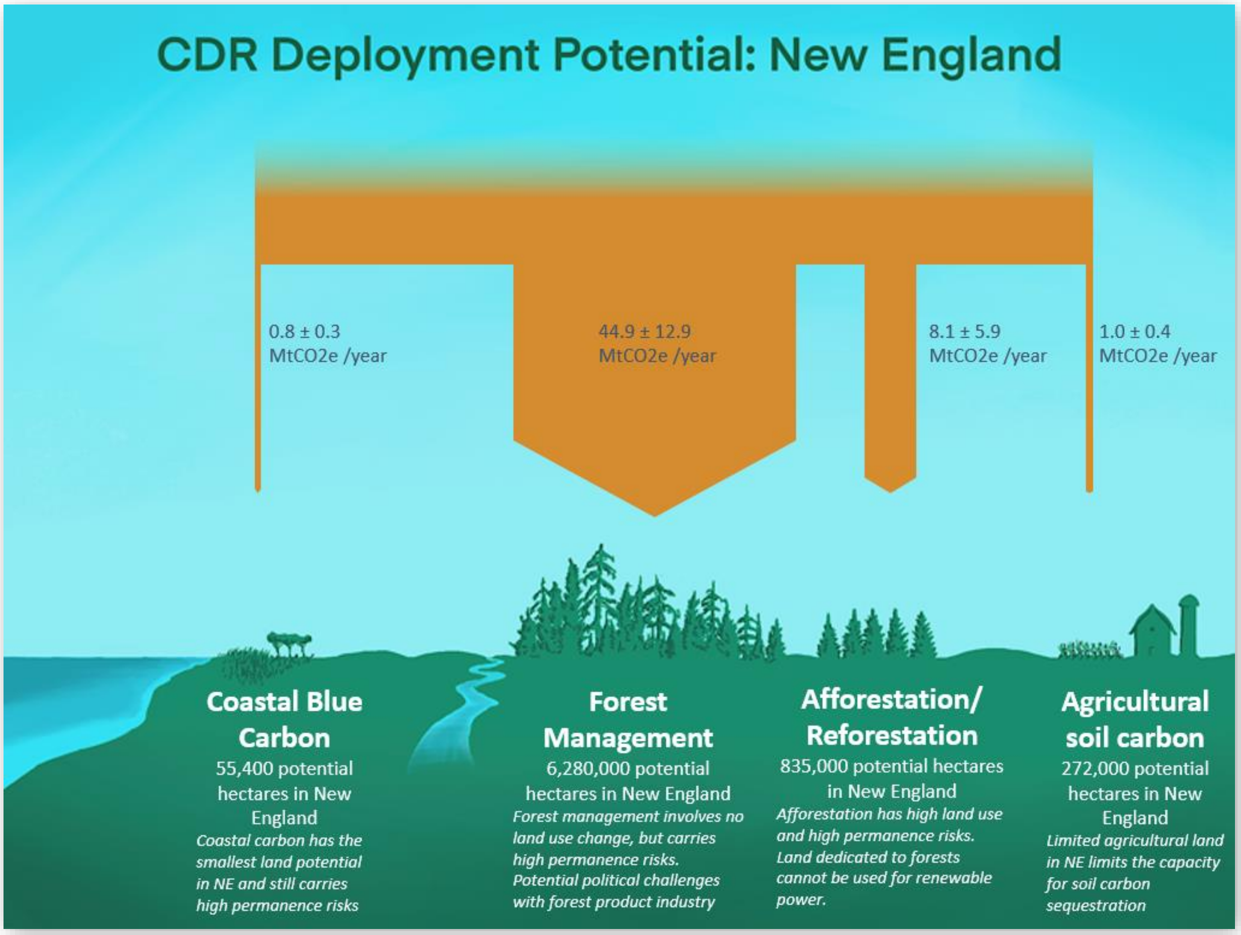
The bottom-up estimate of CDR potential for the four aforementioned natural methods are based on removal potentials, given in units of tCO_2 per hectare per annum, multiplied by the land area available for the given CDR approach in the selected region. The top-down estimate uses national-level potentials, scaled to the proportion of national land area available for that approach that is located in the selected region. These estimates are blended to give a final range. These estimates are not the full technical potential for the region; they use a restricted set of available land or CDR methods in order to approximate a more realistic potential given economic and social concerns. For example, the afforestation/reforestation approach assumes that an equivalent land area to forest cover lost in New England over the last two decades can be reforested.

The results of the deployment potential analysis demonstrate that forestry approaches have the highest potential in New England, with forest management potentially removing 32 to 58 MMT CO_2 per year and afforestation/reforestation 2 to 14 MMT CO_2 per year. Parts of New England are already heavily forested, and the region has strong forestry industries, especially in Maine. Though coastal blue carbon and agricultural soil show less overall potential, providing about 1 MMT CO_2 per year each, they still merit investment, as they can be inexpensive parts of a CDR portfolio and have numerous co-benefits. Cumulatively, the identified CDR potential is equivalent to 21 to 43% of New England's 2016 GHG emissions.

The high variability in potential for the forestry approaches is mostly attributable to uncertainty about the amount of land that would be practically available for these CDR approaches, rather than doubts about their ability to achieve carbon removal (which has been well documented over decades of deployment). With sufficient ambition, however, these estimates indicate that CDR (and forestry approaches in particular) could make significant progress toward achieving net-zero emissions in New England.

The predominance of forestry approaches in this analysis also highlights a major data gap when discussing New England's emissions: the *current* carbon flux of the region's forested areas is not known. Most of the region's emissions inventories do not include the Land Use, Land Use Change, and Forestry inventory sector. Those that do (Massachusetts and Vermont) do not include it in their emissions totals; in Vermont's case, including it would reduce the state's total emissions by about half.[44] The exclusion of this category is attributable to a lack of reliable data or methodology for estimating it; according to the Rhode Island Inventory: "The SIT [EPA State Inventory Tool] has been unreliable for estimating emissions and/or sequestration of emission for this sector and no alternative methodology has been developed."[45] An important part of any policy effort in New England to promote CDR should include a component devoted to measurement, to better understand both the baseline of negative emissions in the region and the impact of natural CDR approaches as they are deployed.

Figure 5-2. Ranges for Natural CDR Potential in New England



5.3 A New England Innovation Agenda

This report's modeling identifies how New England can achieve deep reductions in direct greenhouse gas emissions using technologies that are currently available or will soon become so. However, a wide variety of innovations—currently the subjects of lab research or early commercialization efforts—could offer new, potentially less costly options to reaching the region's climate goals. These innovative technologies, processes, and business models could reduce the costs of direct mitigation, offer ways to extend direct mitigation to address a greater share of current emissions, and offer improved CDR systems to compensate for whatever emissions remain. The increased optionality that innovation provides can only increase the likelihood that New England achieves carbon neutrality by 2050.

Further technology development is essential to realize the scenarios modeled in this report. The projected cost reductions in solar panels, grid batteries, electric vehicles, and other existing technologies assume continuing design and manufacturing optimizations. Breakthrough innovation can also fulfill the promise of technologies in early stages of commercialization today (e.g., hydrogen systems and small modular reactors), provide energy system cost reductions beyond those in this report's best-case scenarios, provide new options to achieve those scenarios, and address the emissions not covered in the economy-wide modeling.

Since innovation assets and needs vary across the country, a regional innovation strategy is an essential component of a larger plan for decarbonization. This section analyzes breakthrough innovation that could address key issues for New England highlighted elsewhere in the report, as well as existing areas of strength for the region, and combines those analyses to identify priority areas for an innovation agenda.

This analysis has identified four areas for innovation that can help New England address key issues:

+ As this report's electricity sector modeling found, if **dispatchable low-carbon resources** are available, they tend to complement intermittent renewable resources and energy storage in a least-cost low-carbon energy system. Such resources can ensure grid stability during cold snaps, prolonged periods of low wind and sun, and other emergencies, offering a service that only an unrealistic amount of wind and solar could provide. Innovation could increase dispatchable low or zero carbon generation options beyond those that exist today. Long-duration storage could also fill a similar niche in providing low-carbon dispatchable power.

+ All scenarios modeled in this report depend to some extent on **low-carbon fuels**, including biofuels and hydrogen. Innovation is necessary to decrease the cost of those fuels but could also introduce new fuel options. Low-carbon fuel innovation could also abate some emissions from "difficult to decarbonize" subsectors like aviation and long-distance road transport where liquid fuels' energy density is currently essential. Renewable fuels--including hydrogen, biofuels, ammonia, and power-to-gas/power-to-liquids--are a promising set of tools to address these use cases. Cost-effective production is the most critical area of research for all of these fuels, though adaptation of end-use devices and distribution systems will also be necessary.

+ Other **hard-to-abate** emissions come from high-temperature industrial heating and industrial processes like cement production, pulp and paper production, and chemicals manufacturing. Innovation in a variety of areas—including carbon capture and low-carbon fuels—is necessary to abate these emissions, as many of them cannot be addressed by electrification.

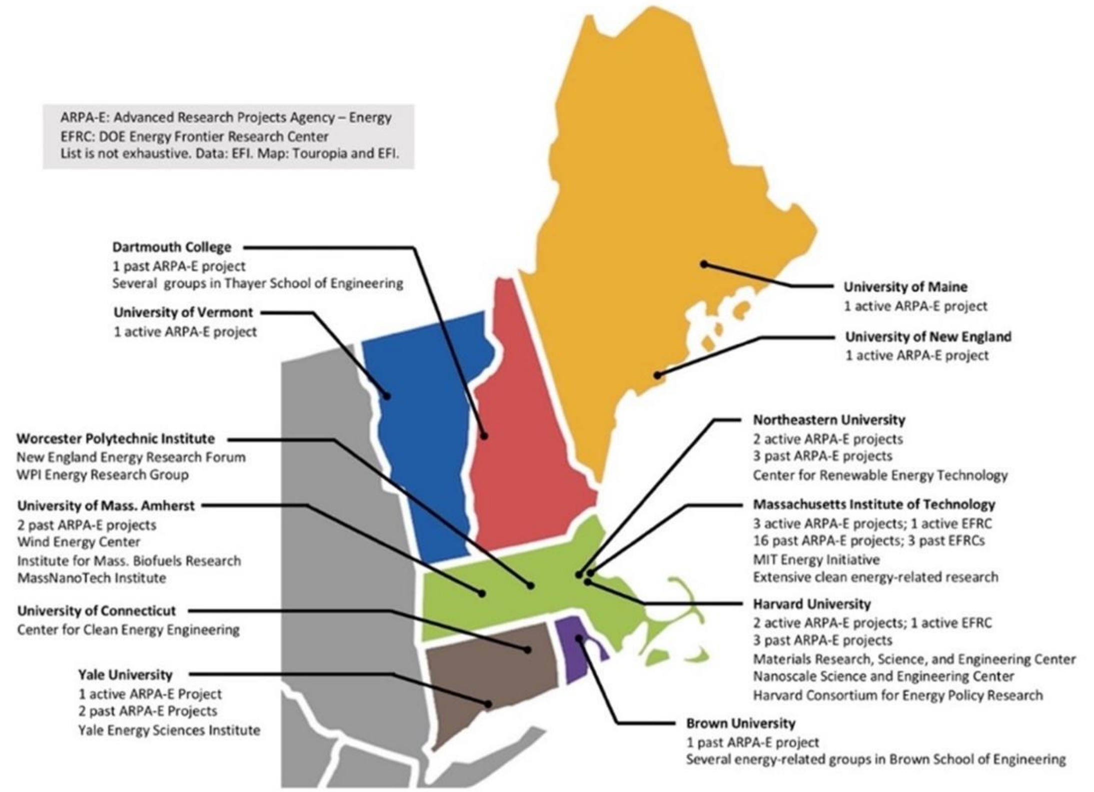
+ **CDR** could become a key tool for achieving carbon neutrality, and there are CDR approaches that can be deployed at scale in New England today. Innovation can make those approaches both more efficient and open up new possibilities for CDR. This optionality could bring down the cost of CDR, as well as mitigate concerns with natural approaches, such as land use and threat of reversal.

5.3.1 New England's Innovation Assets

New England's greatest strengths in energy innovation lie in its universities and its cleantech companies. These assets, matched to the region's particular needs, can help shape a regionally tailored low-carbon innovation portfolio. Though the region hosts activity in almost every subsector of clean energy, R&D in hydrogen, biofuels, and energy storage are especially strong suits. In addition to technology development, the region has capacity for continued policy innovation.[bb] Few regions worldwide can rival New England's density of world-class universities and research institutions. Academic research funding from the Department of Energy, illustrated in Figure 5-3, gives a sense of the volume of cutting-edge projects under way.[46] Universities host several of the Department of Energy's Energy Frontier Research Centers, many ARPA-E (Advanced Research Projects – Energy) grantees, and numerous other energy-related labs.[47,48] These schools contribute not only by developing novel technologies but also by creating a workforce of engineers, scientists, and other innovators who can apply their talents in the private sector.

[bb] New England states have also been policy innovators in many respects. Connecticut was the first state in the U.S. to have a Green Bank, which specifically provides clean energy financing to homeowners, businesses, other institutions. Connecticut was also among the first states to enact a policy specifically recognizing the zero carbon power generated by nuclear power plants by allowing local nuclear generators to qualify for carbon-free power contracts in the state's procurement process. Massachusetts is the first in the nation to pass a Clean Peak Standard that provides enhanced incentives for energy storage and renewable resources to provide power during power system peak hours.

Figure 5-3. DOE Grantees and Clean Energy Research Centers in New England



New England's universities are home to numerous Department of Energy grantees and research centers, as well as to many interdisciplinary hubs for energy-related research.

Private sector innovation in New England involves both startups and existing players in the clean energy space. The region has a strong population of early-stage startups, established startups, and multinational firms with offices and R&D presences. Though much activity centers around urban hubs like New Haven, Providence, and Boston, private sector innovation exists in numerous cities in each of New England's states.[49] Companies at all stages of development have also received funding from ARPA-E and other government programs to sponsor their research.[50]

Appendix 7.7 discusses key academic and private-sector innovation assets in New England within each breakthrough area.

5.4 Regional Innovation Priorities

Table 5-2 summarizes several key areas in which advances could reduce the cost and increase the functionality of New England's low-carbon energy systems. The breakthrough areas listed above are divided into specific innovation priorities. Where relevant in-region expertise intersects with local innovation needs, New England can invest directly in continued focus on critical issues. Research funding and grants for first-of-a-kind demonstrations can help support this work. In other situations, cutting-edge research in a field critical to New England's decarbonization may take place elsewhere. For instance, the small modular reactors that are closest to market were developed in the Pacific Northwest, and industrial electrification hinges on multinational equipment companies' product offerings. In these cases, New England can adopt policies to create demand for distant companies' low-carbon products.

The technologies discussed below are at various stages of the innovation process. Even if technological hurdles can be overcome, challenges may remain in regulation, siting, feedstock availability, and public acceptance. Innovations in policy and business models are also likely prerequisites to deployment. The table's final column addresses those issues.

Table 5-2. Summary of Innovation Assets in Key Areas

Breakthrough Area	Sub-Areas of Strength for New England	Academic Innovation Assets	Private Sector Innovation Assets	Barriers to Deployment
Dispatchable Low-Carbon Electricity	Baseload zero-carbon generation: advanced uclear	MIT Nuclear Science & Engineering department	Commonwealth Fusion, Yellowstone Energy	Slow pace of product development; Siting constraints; NIMBYism and public doubt about nuclear.
	Long-duration energy storage: flow batteries, thermal energy storage	University materials science and chemistry departments; various labs spread across different schools.	Many startups; Form Energy and Brayton Energy especially promising.	Difficult to value long-duration storage in current electricity markets, especially until fossil plants can no longer backstop the grid. Cost requirements are very strict.
Low-Carbon Fuels	Hydrogen: fuel cells, electrolyzers	University materials science and chemistry departments; various labs spread across different schools.	Multiple global companies incl. Doosan Fuel Cell America, FuelCell Energy, and Proton OnSite	Cost of hydrogen production, "chicken and egg" scaling problems throughout value chain, incompatibility with current gas-driven equipment, pipeline infrastructure
	Biofuels: cellulosic biofuels, biological fuel upgrading, ocean-derived biofuels	Universities including Harvard, MIT, & UMass Amherst; UMaine Forest Bioproducts Research Institute; Woods Hole Oceanographic Institute	Many startups, incl. some developing biological upgraders; Biofine is developing a pilot cellulosic biofuel plant in Maine.	Cost of advanced biofuel production, need for low-cost feedstocks at scale, environmental/land use impacts
	Power-to-X: reactor design, biological fuel upgrading	Research teams at UMass Amherst, Harvard, and MIT working on biological upgrading.	Startups developing power-to-methanol and power-to-ammonia devices. Others developing biological methanation and upgrading reactors.	CO_2 and H_2 must be available inexpensively as feedstocks; limited demand; lower bounds on power-to-fuel costs are well above fossil fuel costs

Hard-to-Decarbonize Sectors	CO_2 abatement, industrial CCS and advanced electrification, low carbon fuels	Some research on alternative fuels (see above) and CCS; little otherwise	Few active now; Existing industrial and engineering companies can integrate zero-emission industrial equipment if it becomes available.	Extremely diverse energy end uses & devices requiring adaptation; unavoidable need for energy-dense liquid fuels in certain use cases; unavoidable process emissions
Carbon Dioxide Removal	Technologically enhanced natural CDR, policy and business model innovation	University earth and environmental science departments; Woods Hole Oceanographic Institute & Bigelow Laboratory for Ocean Sciences	Strong private forestry and marine industries; Harvard faculty cofounded Canada-based Carbon Engineering	Difficult of quantifying negative emissions from some tech-enhanced natural CDR; expense of technological CDR; lack of demand

More details on each of these regional innovation priority areas is available in Appendix 7.7.

6 Conclusions

The New England states are pursuing a range of ambitious and challenging economy-wide GHG reduction goals. The electricity system will play a key role in achieving New England's climate goals through near-complete decarbonization of electricity supply and supporting the electrification of transportation, buildings, and industry.

Reliable electricity supplies are critical to the functioning of the modern economy and for the health and safety of people everywhere. This will increasingly be true in an electrified future in which New Englanders rely at least in part on electricity for heating and mobility on the coldest winter days. At the same time, decarbonizing the electricity system will require New England to deploy significant quantities of wind, solar, and energy storage resources. While these intermittent and/or energy-limited resources can make significant contributions to reliable electric system operations, numerous studies in other regions have demonstrated that complementary resources will continue to be needed to provide essential grid services and to generate electricity during extended periods of low wind and solar generation.

The following key findings provide new insight into how the New England electricity system can reliably accommodate this dual challenge of growing electricity demand—increasingly characterized by peak winter heating demand—and reducing emissions to nearly zero.

1. **Decarbonizing New England requires transformational change in all energy end-use sectors.** New England has long been an environmental policy leader, with progress in recent decades aided by the region's transition from oil and coal to natural gas. Today, direct energy use for transportation and buildings makes up two-thirds of the region's emissions. Key strategies for mitigating economy-wide greenhouse gas emissions are: (1) aggressive deployment of energy efficiency; (2) widespread electrification of end uses in the building, transportation and industrial sectors; (3) development of low-carbon fuels; and (4) deep decarbonization of electricity supplies.

2. **Electricity demand will increase significantly in New England over the next three decades under the net-zero scenarios studied.** In the two primary bookend scenarios, annual electricity demand grows by 70 to 110 Terawatt-hours (TWh), roughly 60 to 90% from today. Electric peak demand reaches 42 to 51 Gigawatts (GW) as the system shifts from summer to winter peaking in the 2030s. This demand growth is primarily due to electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. This large increase in electricity demand occurs despite significant energy efficiency included in the scenarios. Absent energy efficiency, demand growth would be even higher.

3. **Renewable electricity generation will play a major role in providing zero-carbon energy to the region.** The Base Case scenarios select a diverse mix of 47 to 64 GW of new renewable generation capacity by 2050, including land-based solar and wind, offshore wind, and distributed solar, along with 3.5 GW of incremental Canadian hydro. Renewable generation is needed to displace fossil fuel generation in the electricity system and to provide zero-carbon energy for vehicles, buildings and industry. Greenfield development will be required to reach adequate scale, even if opportunities to develop brownfield sites, rooftops, and marginal lands are maximized, notwithstanding the region's

limited availability of land for renewable energy development. New England's constrained geography, slow pace of electric transmission planning, and historical difficulty siting new infrastructure are significant challenges that the region must overcome.

4. **A cost-effective, reliable, and decarbonized grid requires firm generating capacity.** Firm capacity is capacity that can provide electricity on demand and operate for as long as needed; today, natural gas and nuclear generation are the primary sources of firm capacity in the region. While today's renewable generation and battery storage technologies will play large roles in the future New England system, relying on these resources alone would require very large quantities of renewables and storage and would be extremely costly. In practice, as much as 46 GW of firm capacity could be needed in 2050 to ensure resource adequacy; our Base Case includes about 34 GW of gas generation, 3.5 GW of nuclear, 8 GW of imports and 1 GW of biomass and waste (under High Electrification loads). Significant gas capacity is retained even though the gas plants operate far fewer hours and contribute less energy (and emissions) to the region than today. New resources may be developed and deployed in the future to provide low-carbon firm capacity such as advanced nuclear, natural gas plants with carbon capture and sequestration (CCS), long duration energy storage, or generation from carbon-neutral fuels such as hydrogen. These resources would require significant investments in supporting infrastructure; for example, natural gas with CCS or hydrogen would require dedicated pipeline infrastructure connecting New England to regions with suitable geology for carbon sequestration or hydrogen storage. Until one or more of these technologies is widely and commercially available, natural gas generation is the most cost-effective source of firm capacity, and some reliance on gas generation for resource adequacy is consistent with achieving a 95% carbon-free electricity grid in 2050 as long as the generation operates at a suitably low capacity factor.

5. **A broader range of technology choices lowers costs and technology risks.** The availability of low-carbon firm generation technologies – such as advanced nuclear or natural gas with CCS – could provide significant cost savings and reduce the pressure of renewable development on New England's lands and coastal waters. The 2050 incremental cost to achieve an electricity sector target of 2.5 MMT CO_2e relative to a Reference Case (50% renewables) falls roughly in half when natural gas with CCS is made available, assuming technology cost declines are achieved. When advanced nuclear technology is also available at scale, the cost of decarbonization declines further. In addition to reducing direct costs, a portfolio approach for ensuring the availability of low-carbon firm generation resources mitigates the risks associated with the possibility that one or more technology options does not materialize as expected. Issues including uncertain innovation time horizons, difficulty building supporting infrastructure, incompatibility with other policy goals, or alignment with the decisions of neighboring regions may limit the role of some technologies in helping meet New England's climate goals.

6. **Achieving net-zero GHGs requires carbon dioxide removal (CDR), and New England's extensive stock of healthy forests and local forest management expertise provide an ideal local opportunity for CDR.** While CDR alone will not be enough to achieve economy-wide decarbonization or meet the region's policy targets, it supports achieving full carbon neutrality and potentially net-negative emissions in New England and beyond. The lack of suitable geology for carbon sequestration make

direct air capture and bioenergy with carbon capture and storage poorly suited to the region, but a large stock of forests provides a good opportunity for in-region CDR. A more purposeful and explicit consideration of the carbon sequestration potential of New England's forests would help the region better manage tradeoffs between preserving forest land and new greenfield renewable energy development. Policymakers should consider incorporating practices that promote CDR across its forest lands, as well as other natural CDR options, which are the best candidates for near-term deployment.

7. **Achieving the commercialization of emerging technologies can be aided by leveraging regional innovation capacity.** New England's innovation ecosystem is one of the most robust in the world. Local policymakers can increase the likelihood of commercializing emerging technologies by orienting the homegrown efforts of private, public, and academic researchers already developing science and business innovations relevant to decarbonization. Specifically, advanced nuclear, long-duration storage, and renewable fuels are innovation areas that have tremendous regional potential and could play a role in supporting a low-carbon power sector, especially when local innovation efforts are coordinated with federally-funded programs.

7.1 Detailed PATHWAYS Assumptions

As discussed in the main body of the report, this study relied on E3's PATHWAYS model for the New England region. Below we provide detailed study assumptions used as part of this analysis.

7.1.1.1 Base year energy demand benchmarking

The New England PATHWAYS model includes a representation of energy demand in the commercial, residential, transportation, and industrial sectors. To further disaggregate energy demand into subsectors, we use a variety of data, sourced primarily from federal data sets and surveys such as the EIA National Energy Modeling System (NEMS); the Residential Energy Consumption Survey (RECS); the Commercial Buildings Energy Consumption Survey (CBECS); the State Energy Data System (SEDS); and Department of Transportation (DOT) data on vehicle mileage. See Table 7-1, Table 7-2, and Table 7-3 below for further details on representation of energy demand within the buildings, transportation, and industrial sectors in the PATHWAYS modeling for 2015, the first simulated year.

In calculating energy demands, E3 benchmarked energy consumption within each state to state level data from the EIA SEDS, which reports fuel consumption by economic sector and fuel in each state. E3 performed a bottom-up based accounting of the appliances and vehicles in the region, and relied on a variety of federal data on appliance and vehicle efficiencies, as well as usage patterns, to benchmark residential, commercial, and transportation energy demands within the region.

E3 used two modeling approaches to analyze energy demand in each sector: (1) stock rollover, in which an explicit accounting of rollover appliances and equipment were calculated and used to account for energy and GHG emissions; or (2) total energy by fuel, in which the total energy consumption was directly modeled. The stock rollover approach was used when infrastructure data were available from public data sources; when only limited or poor quality data on stock existed, E3 used a total energy approach.

Table 7-1. Representation of 2015 New England Energy Demand by Subsector in Buildings

Sector	Subsector	Modeling approach used	Energy use in 2015 (Tbtu)	Percent energy use in sector in 2015 (%)
Commercial	Air Conditioning	Stock rollover	13,847	3%
	Cooking	Stock rollover	18,032	4%
	General Service Lighting	Stock rollover	13,383	3%
	High Intensity Discharge Lighting	Stock rollover	1,904	0%
	Linear Fluorescent Lighting	Stock rollover	13,888	3%
	Other*	Total energy by fuel	97,822	23%
	Refrigeration	Stock rollover	41,655	10%
	Space Heating	Stock rollover	185,868	43%
	Ventilation	Stock rollover	27,066	6%
	Water Heating	Stock rollover	17,139	4%
Residential	Building Shell	Stock rollover	N/A**	0%
	Central Air Conditioning	Stock rollover	3,688	1%
	Clothes Drying	Stock rollover	9,122	1%
	Clothes Washing	Stock rollover	833	0%
	Cooking	Stock rollover	8,387	1%
	Dishwashing	Stock rollover	3,781	1%
	Exterior Lighting	Stock rollover	2,117	0%
	Freezing	Stock rollover	2,165	0%
	General Service Lighting	Stock rollover	12,885	2%
	Linear Fluorescent Lighting	Stock rollover	2,186	0%
	Multifamily residence space heating	Stock rollover	165,054	23%
	Other*	Total energy by fuel	58,148	8%
	Reflector Lighting	Stock rollover	2,933	0%
	Refrigeration	Stock rollover	14,251	2%
	Room Air Conditioning	Stock rollover	5,600	1%
	Single family residence space heating	Stock rollover	324,886	46%
	Water Heating	Stock rollover	92,031	13%

**Residential and commercial other includes all other energy categorized as "Residential" or "Commercial" within the SEDS, but which we have no stock rollover data available: these include, but are not limited to, devices such as furnace fans, plug loads (e.g., computers, phones, speakers, printers), secondary heating, fireplaces, and outdoor grills.*

***The building shell subsector does not demand energy, but affects the demand for space conditioning; an efficient building shell reduces energy demand for space heating and air conditioning relative to a non-efficient reference shell.*

Table 7-2. Representation of 2015 New England Energy Consumption by Subsector in Transportation

Sector	Subsector	Modeling approach used	Energy use in 2015 (Tbtu)	Percent energy use in sector in 2015 (%)
Transportation	Light Duty Vehicles (Auto)	Stock rollover	524,532	51%
	Light Duty Vehicles (Trucks)	Stock rollover	182,987	18%
	Buses	Stock rollover	537	<1%
	Heavy Duty Vehicles	Stock rollover	125,166	12%
	Medium Duty Vehicles	Stock rollover	61,462	6%
	Aviation	Total energy by fuel	84,915	8%
	Other	Total energy by fuel	54,546	5%

Table 7-3. Representation of 2015 New England Energy Consumption in Industry

Sector	Subsector	Modeling approach used	Energy use in 2015 (Tbtu)	Percent energy use in sector in 2015 (%)
Industry	Not disaggregated for this study	Total energy by fuel	309,689	100%

7.1.1.2 Forecasting energy demand in future years

Demands for energy services in PATHWAYS are driven by forecasts of population, building square footage, vehicle miles traveled, and other drivers of energy services. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs. PATHWAYS calculates energy demand, GHG emissions, and the portfolio of technology stocks in selected sectors, on an annual basis through 2050. When forecasting energy use, E3 used a variety of sources including EIA and NREL forecasts of appliance efficiencies and vehicle efficiencies, in conjunction with underlying macroeconomic drivers derived from the Annual Energy Outlook (AEO).

Table 7-4. Key Drivers of Energy Services Demand by PATHWAYS Sector

Sector	Key Driver	Compound annual growth rate [%]	Data Source
Residential	Population	0.3%	US Census Bureau, Population Division 2019
Commercial	Commercial square feet	0.5%	Downscale of US AEO nationwide commercial growth relative to regional population growth
Industry	Energy growth	Varies by fuel	EIA AEO
On Road Transportation	Vehicle-miles traveled (VMT)	0.5% LDV 1.3% MDV 1.2% HDV	EIA AEO
Off Road Transportation	Energy growth	Varies by fuel	EIA AEO
Electricity Generation	Electric load growth	Varies by scenario	Built up from energy demands in Buildings, Industry, Transportation

7.1.1.3 Electric load forecast

Since the PATHWAYS model is based on a bottom-up forecast of technology stock changes across the economy, the model does not use a single load forecast or energy efficiency savings forecast as a model input. The electric load forecast is an outcome of the stock change and efficiency improvements embedded in each scenario; these modeling assumptions may not reflect specific future energy efficiency programs or activities, but are meant to produce loads consistent with a range of approaches to achieving carbon neutrality across the economy.

7.1.1.4 Electric load shaping

To maintain electric system reliability, it is important to match the temporal supply and demand of electricity. The mitigation scenarios characterized in this study include adoption of electric vehicles and building electrification, which can significantly change the historical relationship between temperature conditions and electric load. To capture this dynamic, this study scaled historical system load shapes to future years to form the basis of the hourly load forecast, and adjusted this projected hourly load forecast by accounting for simulated end-use load shapes for light duty transportation and electric heat pumps.

E3 used its proprietary load-shaping tools to simulate load shapes for light duty transportation and electric space heating. Given its importance for this study, these tools are described in detail in Section 7.2.

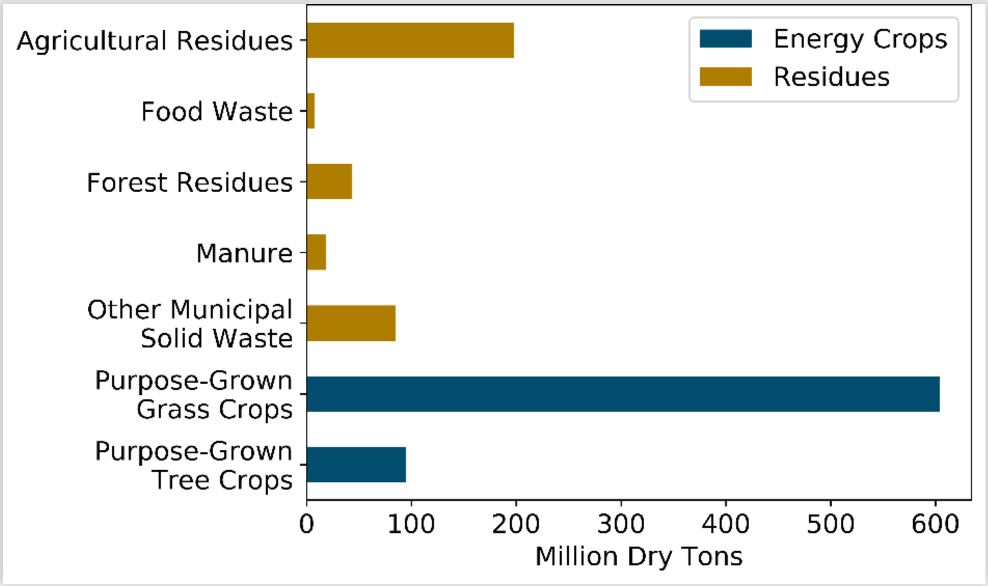
7.1.1.5 Low-carbon fuels

To decarbonize under a High Fuels scenario, we assumed the usage of advanced renewable biofuels and hydrogen as low-carbon fuel options. To analyze availability of low-carbon biofuels feedstock, E3 relied on a U.S. Department of Energy report on biomass availability within the United States, the *2016 Billion-Ton Report.* This report provides county-level estimates of sustainable potential biomass production for a variety of feedstocks, including agricultural, forestry, and waste streams.

Figure 7-1 the national estimated biomass feedstock supply. The "Residues" category includes agricultural residues, food waste, forest residues, municipal solid waste, and manure – feedstocks that typically have fewer concerns about land-use constraints and competition with food crops. For this reason we limited biomass feedstocks to residues, excluding purpose-grown energy crops.[cc]

To determine available sustainable biomass supply through our study period, we assumed that New England would have access to its population-weighted share of the total national feedstock supply, which is about 4% of the total U.S. supply of non-purpose-grown feedstocks. This approach assumes that all U.S. states begin to transition to developing advanced biofuels with these resources, such that a robust market emerges.

Figure 7-1. United States Projected National Biomass Feedstock Supply in 2050



Notes: For this study, E3 relied on the residues only, and assumed New England had access to about 4% of total U.S. supply.

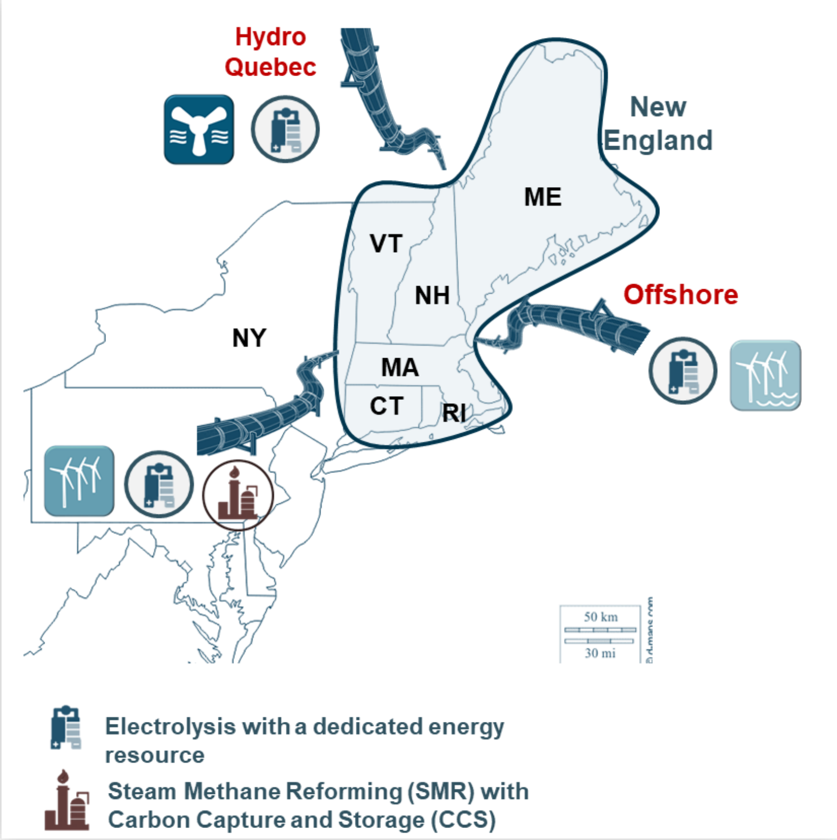
To calculate the optimal portfolio of biofuels, E3 has developed a model which generates biofuel supply curves that determine the availability and cost of renewable liquid and gaseous fuels. The model optimizes the selection of combinations of feedstocks and conversion pathways. The model adds preparation, process, transportation, and delivery costs to Billion Ton Report feedstock cost curves to achieve supply curves by feedstock and conversion pathway.

In addition to advanced biofuels, another low-carbon fuel option used in this study is hydrogen. While the current dominant source of hydrogen in the United States is steam methane reformation of natural gas, an emissions-intensive process, future sources of carbon-free hydrogen include electrolysis with a dedicated

[cc] We note that purpose-grown crops are excluded from the entire analysis, both for the U.S. and New England.

zero-carbon electricity source or SMR with carbon capture and sequestration. The future cost of this zero-carbon fuel is highly uncertain today. For this analysis, E3 assessed that hydrogen was unlikely to be produced and stored within the region, given lack of underground geologic storage options. Instead, we identified multiple potential hydrogen production approaches and locations that could be used to produce hydrogen for use in New England: Pennsylvania onshore wind, Canadian hydro, and offshore wind. In all cases, we assume a dedicated pipeline would transport hydrogen to New England from its origin.

Figure 7-2. Potential Hydrogen Production Sources for New England (Not Exhaustive)



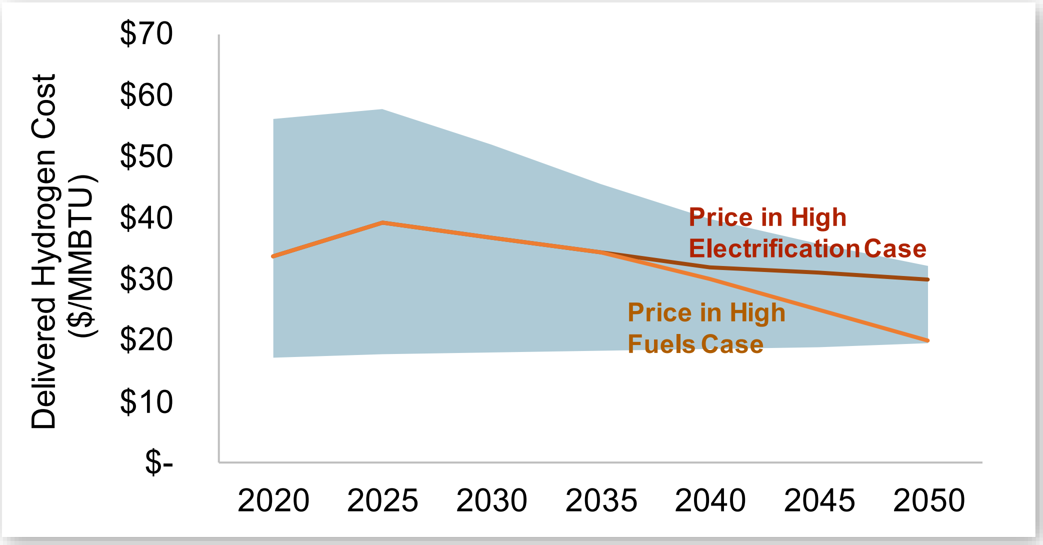
Based on an internal analysis of hydrogen production costs that reflect currently available technologies, projected market development for future production pathways, and delivery and storage costs, E3 estimated a range of delivered hydrogen costs for the New England region. This range in costs can be seen in Figure 7-3 below.

By 2050, the lower bound is an optimistic projection of alkaline electrolyzer costs (based on learning curves developed by the Advanced Power and Energy Program at the University of California at Irvine for previous E3 work)[dd], assuming hydrogen production is powered by onshore wind in Pennsylvania and stored in the

[dd] Developed as part of E3's study for the California Energy Commission, "Natural Gas Distribution in California's Low-Carbon Future", available here: https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html

region before being delivered to New England through a 400-mile dedicated hydrogen pipeline. The upper bound is a more conservative estimate of alkaline electrolyzer costs assuming conservative learning rates, powered by offshore wind to produce hydrogen and deliver to New England through a dedicated hydrogen pipeline about 100 miles long.[ee] In the near term, we assume the costs reflect approximately the median cost of delivering hydrogen within our range. However, assuming that a more robust economy-wide hydrogen market occurs in the High Fuels scenario, we assume that by 2035, costs begin to diverge, with the High Fuels scenario cost approaching the low end of the range ($20/mmBtu in 2050), and the High Electrification scenario cost near the top end of the range ($30/mmBtu in 2050).

Figure 7-3. Hydrogen Delivery Cost Range ($/MMBTU)



In terms of the modeling, hydrogen was used as an energy source in fuel cell vehicles in both mitigation scenarios; blended into the natural gas pipeline in the High Fuels scenario; and available as a power generation resource for the electric sector in both scenarios.

7.2 Load Shape Development

E3 developed normalized hourly load shapes for two particularly important sources of electrification, residential space heating and light duty vehicle transportation. The E3 RESHAPE model is used to develop residential space heating load shapes that reflect weather, technology characteristics and household behavior. Similarly, E3 utilized its model, EVGRID-EVLST for light duty vehicle transportation patterns. The rest of New England's electric load is assumed to follow the existing system-wide load shape. The load shape development and the models used are described in the following sections.

[ee] Options for producing and transporting hydrogen from Canada were excluded from the range (and Figure 7-3), after the initial assessment suggested that, given currently available cost information, this option was unlikely to be part of the realistic range of options given our current assessment of the cost trajectory.

7.2.1 RESHAPE: Residential Space Heating Load Shape Development

Residential and commercial space heating in New England is currently dominated by oil-, natural gas-, and wood-burning furnaces and boilers. Displacing or supplementing these appliances with electric heat pumps is a key measure to decarbonize space heating. Unlike other appliances, which produce heat through combustion or by converting electricity to heat, heat pumps work by transferring heat from outside the building to inside the building. The basic process is the opposite of what takes place in an air conditioner or refrigerator.

There are a number of different types of heat pumps used for space heating. A heat pump that draws heat from outdoor air is called an "air-source heat pump" (ASHP), whereas a heat pump that draws heat from pipes buried underground is a "ground-source heat pump" (GSHP, also called a "geothermal heat pump"). Heat pumps can also be distinguished by how they deliver heat: they may deliver hot air for use in a ducted heating system ("air-to-air" or "ground-to-air" heat pump), or they may deliver hot water for use in a hydronic heating system ("air-to-water" or "ground-to-water" heat pump). The heat source (air vs. ground) is important to this analysis, as using outdoor air vs a ground loop as the heat source results in dramatically different heat pump performance characteristics. The home heating system (ducted vs hydronic) is not directly considered, as it does not have a large impact on heat pump performance.

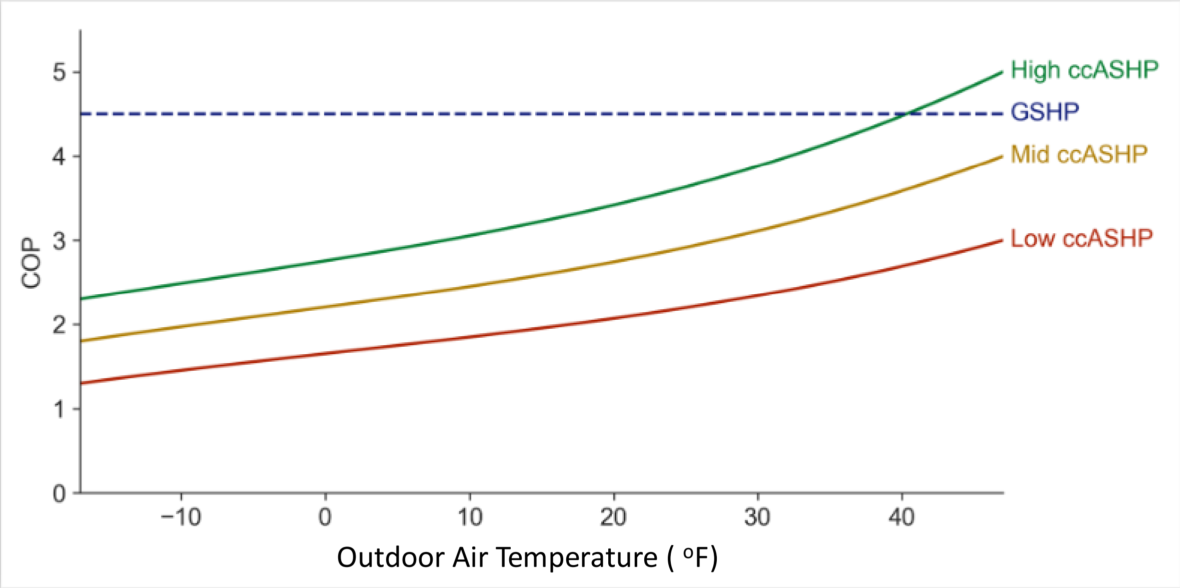
Because heat pumps harness the thermal energy in outdoor air or the ground, they can run at significantly higher efficiencies than other heating appliances that generate heat through combustion. Whereas an efficient furnace may operate at 95% efficiency (i.e. deliver 95% of the available thermal energy in natural gas) and an electric resistance heater operates at nearly 100% efficiency, heat pumps can operate at efficiencies well above 100% and up to 500% or even higher. The efficiency of a heat pump is generally described by the unitized Coefficient of Performance (COP), where a COP of 2 describes a heat pump that requires 1 kWh of electricity to deliver 2 kWh of heat.

In general, the COP of a heat pump in heating mode declines as the temperature of the heat source falls. For ground-source heat pumps, the buried ground loop is approximately the same temperature year-round, so the COP is roughly constant throughout the year. However, air-source heat pumps have a COP that declines as outdoor air temperatures fall.

In this analysis, E3 considered three different ASHP technologies and one GSHP technology. Specifications for the ASHP technologies are based on the cold-climate ASHP (ccASHP) specification and product list from NEEP (the Northeast Energy Efficiency Partnership). The four technologies considered are described below and their COPs are illustrated in Figure 7-4.

+ "Low ccASHP" -- refers to the minimum product specification for NEEP's ccASHP standard. It is important to note that this still describes a high-end appliance in today's marketplace
+ "Mid ccASHP" -- refers to a midrange ccASHP from the NEEP product list
+ "High ccASHP" -- refers to the best ccASHP technologies in the NEEP product list
+ "GSHP" -- refers to a ground-source heat pump with a COP that is independent of outdoor air temperature

Figure 7-4. COP as a Function of Outdoor Air Temperature for the Four Heat Pump Technologies Considered in this Study



The maximum capacity of an air-source heat pump, i.e. the amount of heat it can produce, also declines as outdoor temperatures fall. ASHPs are generally sized to meet a building's heat demands in most hours of the year but may require supplemental heat in the very coldest hours. This supplemental heat (or "backup heat") can be provided by different heat sources and the details may have a large impact on winter peak loads. As New England's electric system shifts to become winter-peaking, the details of supplemental heating in the coldest hours of the year will impact the overall system peak load.

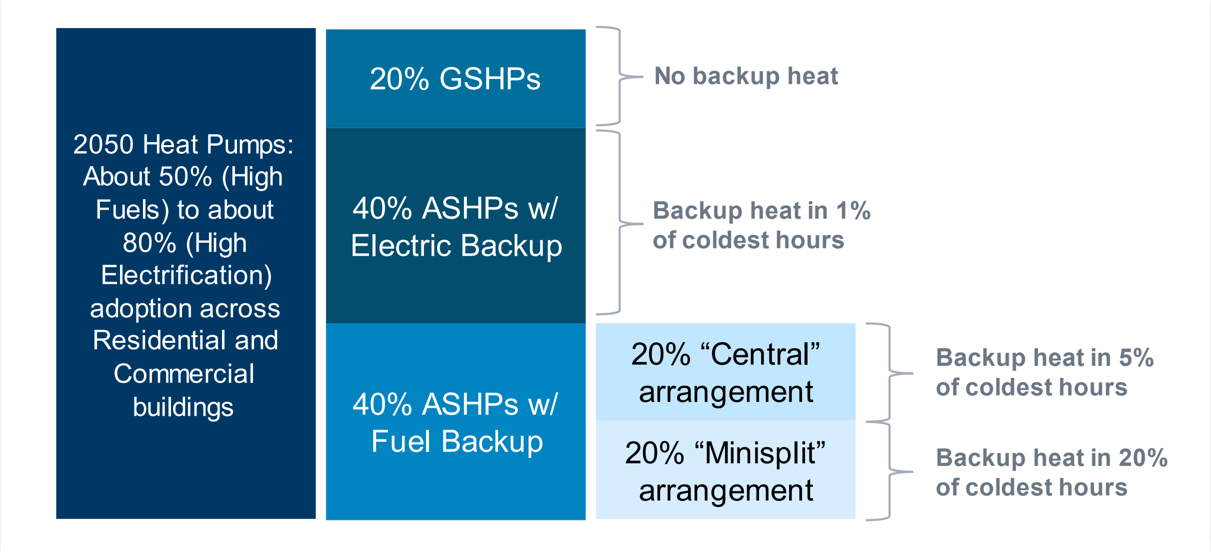
This supplemental heat (or "backup heat") can be provided by different heat sources. In an ASHP with electric resistance backup, the heat pump includes an electric resistance heating element that activates automatically below a certain outdoor temperature. Alternatively, an ASHP with fuel backup describes an ASHP that is paired with a new or existing fuel-based appliance (this is also called a "hybrid heat pump" or a "dual-fuel system"). In a ducted central heating system, if an ASHP is installed in-line with a furnace, the two appliances will not operate simultaneously: in the coldest hours, the ASHP will shut off and all heating demands will be served by the backup heater. Conversely, if the ASHP is installed independent of the fuel-based heater, for example as a packaged terminal ("minisplit") heater, then the ASHP and the fuel backup heater can run simultaneously.

From a system planning perspective, there will be a large incentive to reduce system peak load, and this goal will favor certain technology options. For example, GSHPs would be favored as they run at a high COP in cold hours, leading to relatively small peak impacts. For ASHPS, sizing larger heat pumps would reduce the amount of supplemental heat required in cold hours. Finally, fuel backup systems would reduce peak loads relative to ASHPs with electric resistance backup.

However, if electric rates do not reflect the system value of peak reduction, customers may face a completely different set of incentives. GSHPs have a large upfront cost and may not be widely installed without incentives or customer education on the potential bill savings. Sizing decisions for ASHPs may be made by contractors hoping to reduce upfront cost, with little consideration of the costs of supplemental heat. The choice between electric resistance and fuel-based supplemental heat may depend on whether the customer has a functional fuel-based heater already installed. For customers with fuel backup, the choice of what hours to use the fuel backup may be tied to customer rates rather that a consideration of peak impacts.

Given the large amount of uncertainty, a scenario was designed assuming that a diverse mix of heat pump technologies is ultimately installed in buildings. As illustrated in Figure 7-5, in the High Electrification case, about 80% of buildings see the adoption of heat pump space heaters by 2050. Of these heat pumps, 20% are GSHPs. The remaining 80% are ASHPs, equally split between ASHPs with electric resistance backup and ASHPs with fuel backup. The ASHPs with electric resistance backup are sized to only need backup heat in the coldest 1% of hours. The ASHPs with fuel backup are split into two groups: half installed in a “central” ducted arrangement, which cannot run simultaneously with the fuel backup, and half installed in a standalone “minisplit” arrangement, which *can* run simultaneously with the fuel heater.

Figure 7-5. Heat Pump Technologies Adopted for Residential and Commercial Space Heating



E3's RESHAPE model is used to generate space heating load shapes for use in the RESOLVE and RECAP models. RESHAPE combines a set of characteristic buildings, many years of historical weather, and a physical model of heat pump operation. Building data comes from EIA's RECS and CBECS surveys and weather data comes from NOAA's North American Regional Reanalysis. A description of the RESHAPE model follows.

The first step in the RESHAPE model is developing a geographic sample of representative buildings. The model starts with a database of buildings from the EIA RECS and CBECS surveys, which includes ~1000 residential buildings and ~250 commercial buildings in New England. Next, the model creates a geographic sample of these buildings across the different counties in New England, preserving the appropriate climate zone for each building and using census division data on the representation of different heating fuels in each county to inform the sample.

The second step in the RESHAPE model is using historical weather data to simulate hourly heating demands for each building. Weather data from 1979-2019 is derived from NOAA's North American Regional Reanalysis and is sampled at the county level, enabling a representation of the diversity in weather conditions that may occur across New England. The weather data is combined with data from the building surveys to simulate 41 years of hourly heating for each building in the sample.

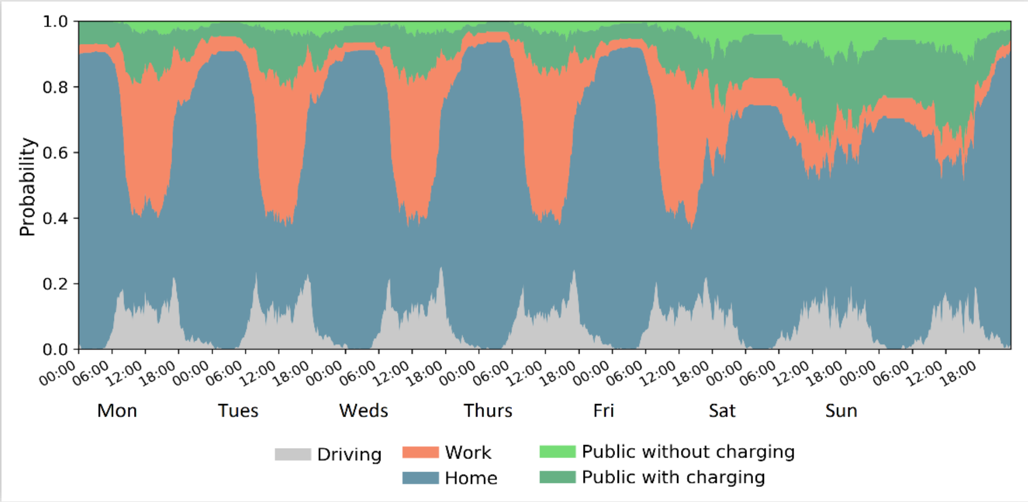
The third step in RESHAPE incorporates the heat pump technologies chosen in the adoption scenario and simulates heat pump operation for each building. As described above, a set of different heat pump technologies are adopted in residential and commercial buildings. These technologies are sampled into the different households in RESHAPE. Next, RESHAPE simulates the operation of these heat pumps (as well as supplemental heat) in order to calculate hourly space heating loads for each building. Finally, these loads are summed up to system-wide hourly space heating loads.

RESOLVE and RECAP use distinct outputs from RESHAPE. RESOLVE uses space heating load shapes for the specific historical days that are represented in the RESOLVE model. These shapes are scaled by annual heat pump loads from PATHWAYS and used to build up system load shapes. In contrast, RECAP uses hourly space heating loads corresponding to all 41 years of weather data (1979-2019) as part of the probabilistic simulations used to calculate ELCCs and target PRM.

7.2.2 EV Load Shape Tool: Transportation Load Shape Development

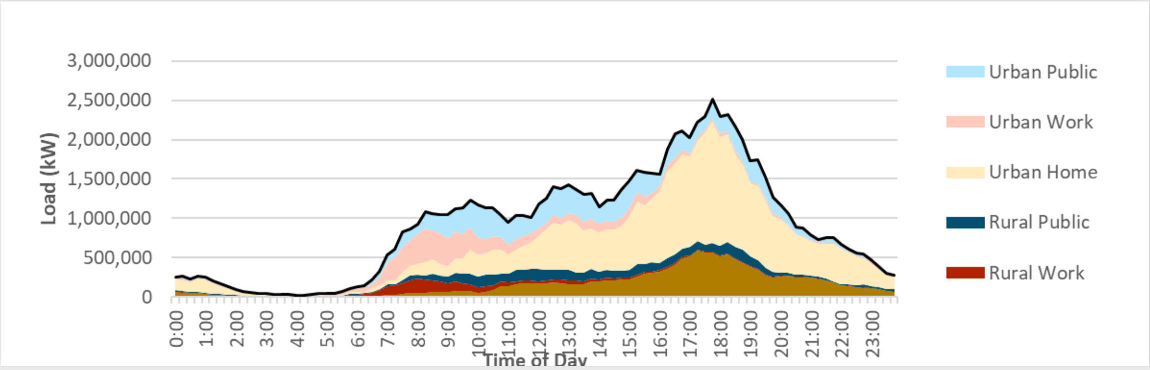
E3's EV Load Shape Tool (EVLST) uses light duty vehicle transportation patterns drawn from the 2017 National Household Travel Survey to simulate EV transportation behaviors and associated charging loads. The dataset is cleaned and filtered for the New England region before it is run through a Markov-Chain Monte Carlo simulation to generate a representative driver sample.

Figure 7-6. Illustrative Weekly Driving Profile Generated for Representative Set of LDV Drivers using the Markov Chain Methodology



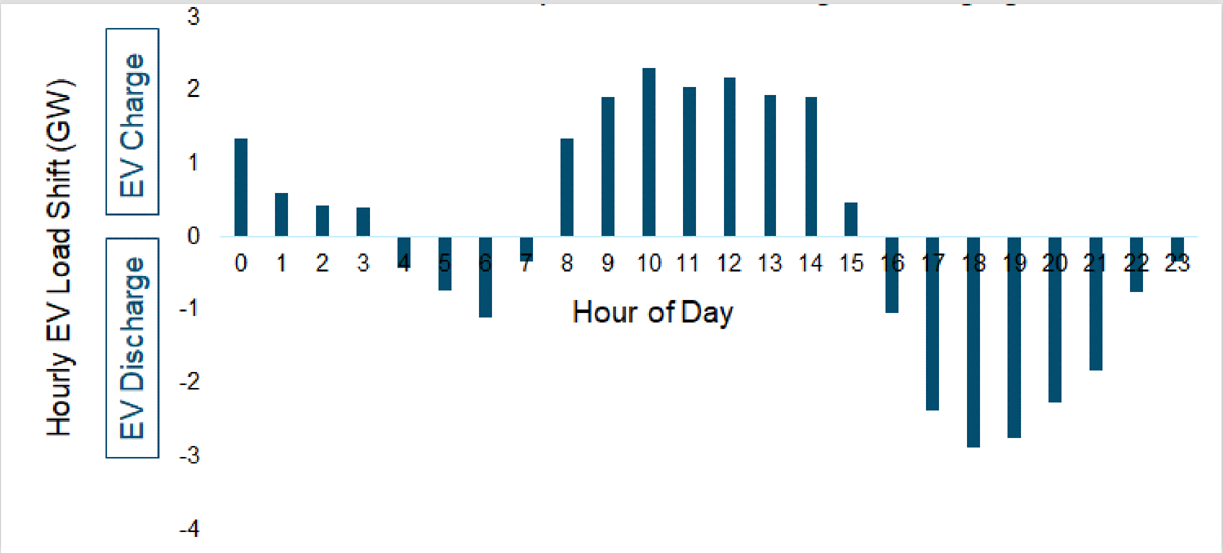
As part of the process to convert driving patterns to charging loads, E3 makes assumptions on the development of charging access and EVSE infrastructure. For this analysis, E3 assumes that by 2050 78% of EV drivers will have access to 6.6 kW Level 2 home charging, while 68% of EV drivers have access to L2 workplace charging. In addition to the high penetration of L2 home / workplace charging, battery electric vehicles will have access to 150 kW public DC Fast Charging. The combination of charging access and high charging powers leads to a world with different combination of driving profiles. These charging access assumptions allows E to generate *unmanaged* charging load profiles, where drivers charge immediately upon arrival at a location where they have access to EV charging infrastructure. These are then adjusted to reflect potential *manag*ed charging profiles.

Figure 7-7. Representative Unmanaged Personal Light-Duty EV Load Shape for New England



E3 has developed a framework to infer a proportion of the transportation load that can be flexible without interfering with a driver's transportation needs. By comparing driving needs, unmanaged load shapes, and the length of time that a driver would spend at a given location, E3 is able to produce an amount of shiftable load per day and a maximum amount of shiftable load in a given hour. Once these parameters are identified, unmanaged EV load is shifted in order to meet RESOLVE's optimal generation profile. Typically, this will mean that in each model day, the shiftable transportation load will move from hours of peak to hours with high wind/solar generation and relatively lower load (and thus low prices). This shifting assumes that by 2050, utilities design rates to encourage charging when energy is the cheapest.

Figure 7-8. Impacts of EV Load Shifting from Managed Charging in 2040



7.2.3 Existing System-Wide Load Shape Development

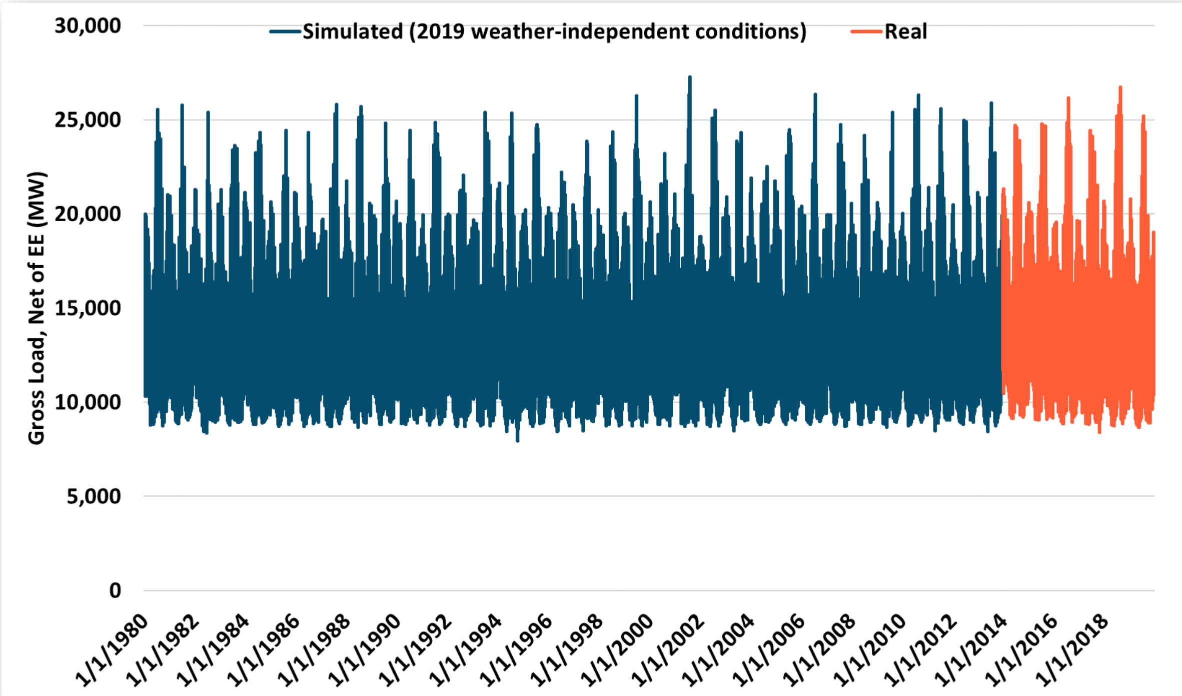
E3 modeled existing (under 2019 weather-independent conditions) hourly load for New England across the weather years 1980- 2019 using a neural network regression model. E3 used hourly load data from 2014-

2019, publicly made available by ISO-NE, to train and test the model. This model captures the relationship between recent daily load and the following independent variables:

- Max and min daily temperature (including one and two-day lag)
- Month (+/- 15 calendar days)
- Day-type (weekday/weekend/holiday)
- Day index for economic growth or other linear factor when using multiple years of historical data to train the model

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1980-2019) under current economic conditions. The final steps convert these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (2014-2019) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh. This hourly load profile for the weather years 1980-2019 is then scaled to match the sum of annual load forecasts for all but the space heating, water heating and light-duty EV loads in future years. The annual load forecasts for all end-uses are outputs from PATHWAYS. Figure 7-9 shows the real and simulated system-wide load. The system-wide load is net of energy efficiency (EE) but grossed up for BTM PV generation since the former is treated as a demand modifier while the latter is treated as a resource in both RESOLVE and RECAP.

Figure 7-9. Real and Simulated New England System Load

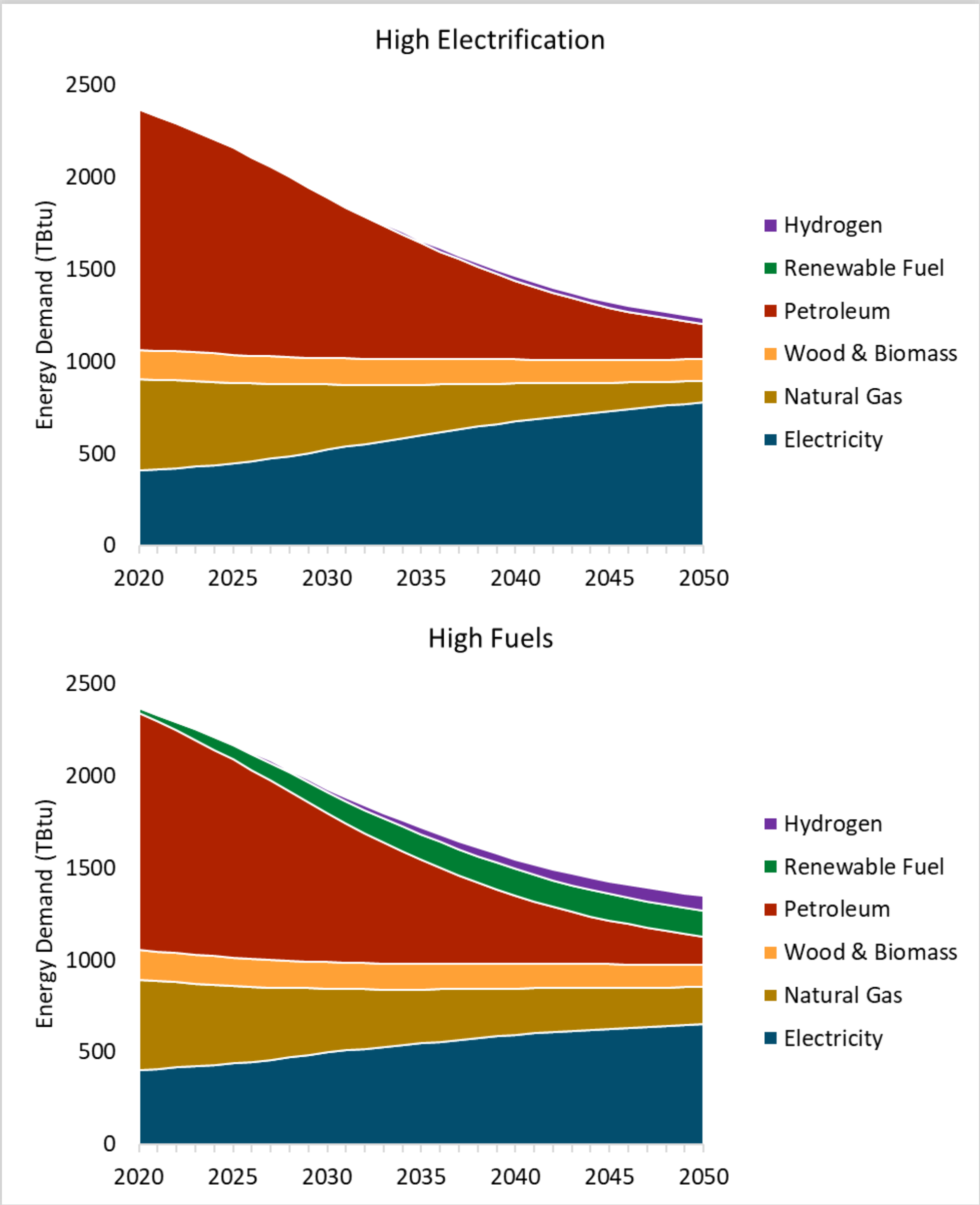


7.3 Additional Economy-wide PATHWAYS Results

Below we provide additional information regarding the results of our economy-wide decarbonization scenarios, including the change in final energy use over time and illustrations of the assumed stock rollover.

As Figure 7-10 shows, by 2030 significant reductions in total energy demand are realized as significant energy efficiency measures and highly efficient technologies are used. By 2050, this trend has accelerated, with total energy demand almost half that of energy demand in 2015. At the same time, a significant increase in decarbonized fuel is assumed: electricity, renewable fuels, and hydrogen use experience significant growth, and conventional petroleum fuel consumption falls considerably. In residential and commercial buildings, both scenarios see increased sales of energy efficient appliances along with behavioral conservation and reductions in heating demand due to deep home retrofits and weatherization measures. The High Fuels scenarios maintains some stock of natural gas heaters, with the use of biofuels and hydrogen in the pipeline to reduce the carbon intensity of heat production, while the High Electrification scenario achieves greater reductions in final energy consumption due to a greater degree of switching from natural gas and oil to electric heat pumps.

Figure 7-10. Final Energy Use by Scenario, 2020-2050[ff]



[ff] This figure shows final energy demand. For electricity consuming devices, this means the figure includes electricity consumed by the device at the plug, but does not include energy consumed by generators to produce electricity (e.g., the natural gas or hydrogen combusted by electricity-producing turbines).

7.3.1 Stock Rollover

Figure 7-11 illustrates the PATHWAYS modeling assumptions utilized for the adoption of LDVs over time, and Figure 7-12 illustrates the modeling assumptions regarding heat pumps over time.

Figure 7-11. Assumed New Light Duty Vehicle Share of Sales (left) and Resulting Stocks (right), High Electrification and High Fuels Scenarios (Both)

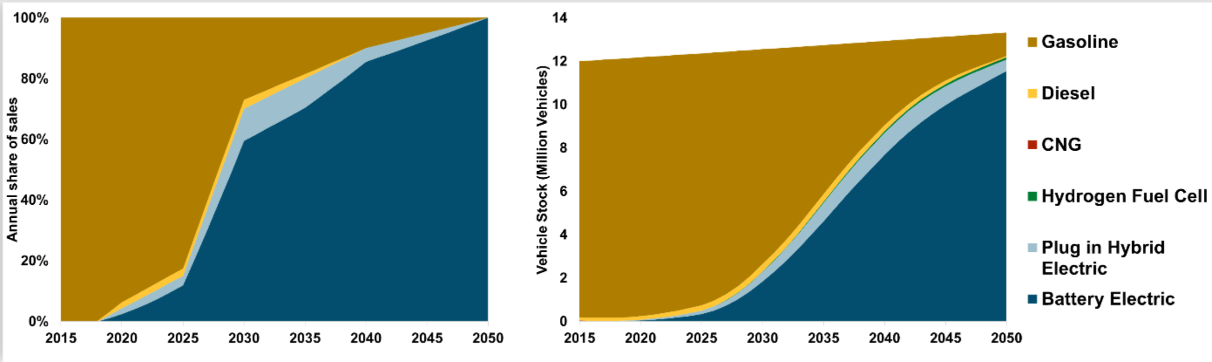
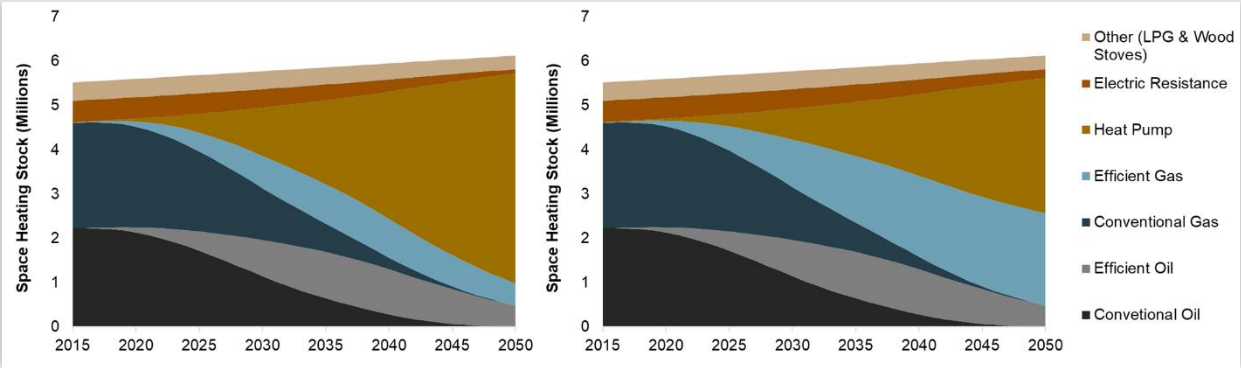


Figure 7-12. Residential Space Heating Stocks in High Electrification (left), High Fuels (right) Scenarios



7.4 New England Reliability (RECAP) Model Assumptions

The following are key assumptions utilized in the RECAP modeling for this study.

7.4.1.1 Load Profiles

E3 modeled existing (under 2019 economic conditions) hourly load for New England across the weather years 1980 – 2019 using a neural network regression model. E3 used hourly load data from 2014-2019, publicly made available by ISO-NE, to train and test the model. This analysis produces expected load profiles in New England under a variety of weather years in today's economic conditions, but does not capture how load profiles might change in the future due to new load types such as electric vehicles or building space and water heating. To capture all of these future load components, E3 paired the neural network model outputs with electric vehicle load modifiers (developed by E3 used its EV Load Shaping Tool, EVLST) and building space and water heating load modifiers (developed by E3 using its RESHAPE model). These profiles were scaled to match annual load forecasts output by PATHWAYS and were combined while maintaining weather correlations. More details on load shape development can be found in Section 7.2.

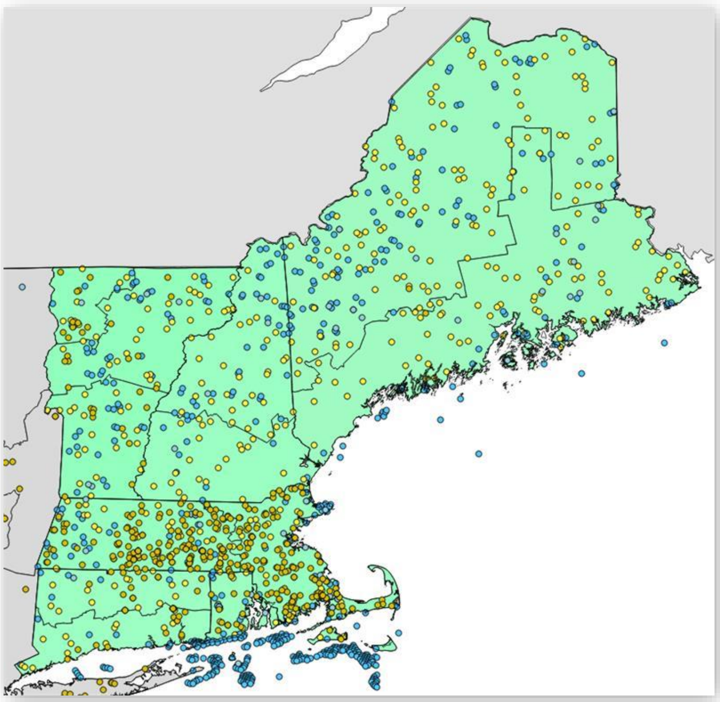
7.4.1.2 Operating Reserves

E3 assumed that the electricity system must hold 3% of the median annual peak load in real-time operating reserves in each hour. To the extent that the system is not able to maintain sufficient operating reserves, the system operator will shed load in order to prevent potentially more catastrophic consequences.

7.4.1.3 Wind and Solar Profiles

Hourly onshore wind and solar profiles were simulated at different sites (shown in Figure 7-13) across New England and hourly offshore wind profiles were similarly simulated within New England's maritime boundaries. The aggregate profiles were aggregated from 300 individual onshore wind sites (representing 4 GW capacity), 400 utility-scale solar sites (representing 4 GW capacity), and 300 offshore wind sites (representing approximately 5 GW capacity). Wind speed and solar insolation data was obtained from the NREL Wind Toolkit and the NREL Solar Prospector Database, respectively. They were then transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2018. Only the coincident period was used to accurately capture correlations.

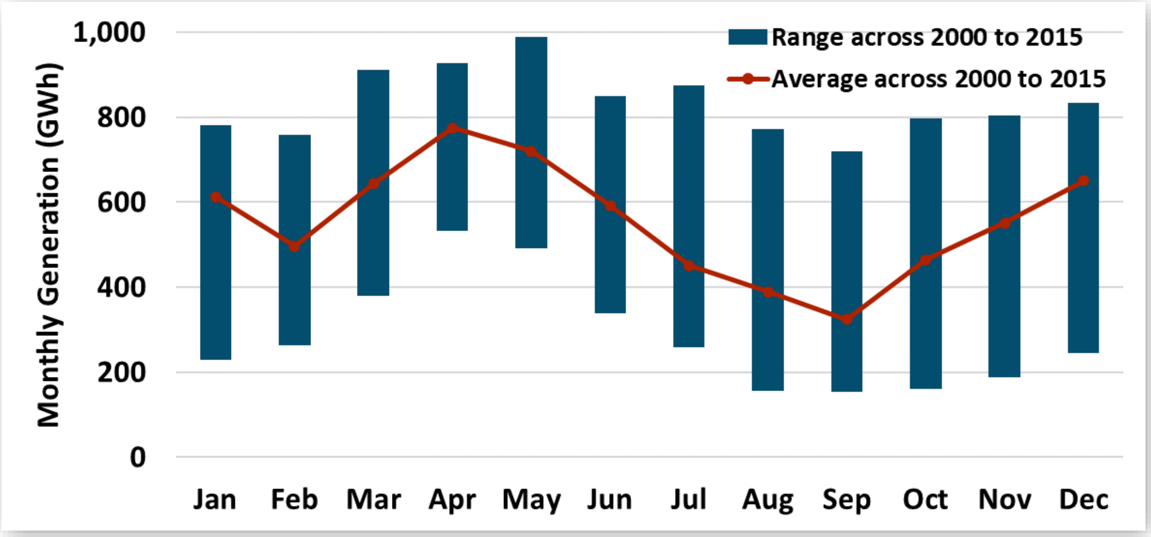
Figure 7-13. Solar (yellow dots) and Wind (blue dots) Sites used to Generate Hourly Generation Profiles



7.4.1.4 Hydro

Hydro is a resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. To determine hydro availability, the model uses a historical record of hydro production data (2000-2015) made publicly available by ISO-NE. One of these "hydro-years" is chosen stochastically to be applicable to a simulated year in RECAP. No correlation between temperature, load, or renewable generation and hydro availability is assumed due to significant lag between weather conditions and hydro availability (i.e., a very snowy December may yield ample hydro availability in April). Choice of a hydro-year determines the hydro energy MWh budget for each month in that year. Hydro is then dispatched based on net load such that higher net load hours have higher hydro generation. Dispatch is further constrained by max/min output.

Figure 7-14. Historical Hydro Generation by Month. Includes Generation from Run-of-River, Pondage and Reservoir Hydro



7.4.1.5 Dispatchable Thermal Generation

Available generation is calculated stochastically in RECAP using forced outage factors (FOF) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states. Over many simulated years, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOF) times the Seasonal Claimed Capability/Nameplate. The MTTR is assumed to be 24 hours and the FOF by generator type is presented in Table 7-5.

Table 7-5. Generator Outage Characteristics

Generator Type	Forced Outage Factor
Gas Combined Cycle/Combustion Turbine	8.6%
Gas Steam Turbine/Internal Combustion	10.0%
Dual Gas-Oil Combined Cycle/Combustion Turbine/Steam Turbine/Internal Combustion	20.2%
Oil Combustion Turbine/Steam Turbine/Internal Combustion	9.2%
Coal Steam Turbine	12.4%
Nuclear Steam Turbine	4.6%
Biomass/Waste	8.6%

7.4.1.6 Imports

Existing firm imports (subject to no generator or transmission outages) from New York, Quebec and New Brunswick were assumed to be 368 MW, 1104 MW and 508 MW, respectively. This is based on ISO-NE's estimation of the tie benefits on external interface connections in 2019. The NECEC line is expected to be in service in 2022, and is attributed with 1090 MW of firm capacity. Any additional external resource/transmission chosen by RESOLVE (if any) is modelled with its respective characteristics, including weather dependence, FOF, and Seasonal Claimed Capability as applicable.

7.4.1.7 Energy Storage

The model dispatches energy storage if there is insufficient generating capacity to meet load and reserves. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. Furthermore, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.

7.4.1.8 Demand Response

The model dispatches demand response if there is insufficient energy storage to meet load and reserve requirements. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

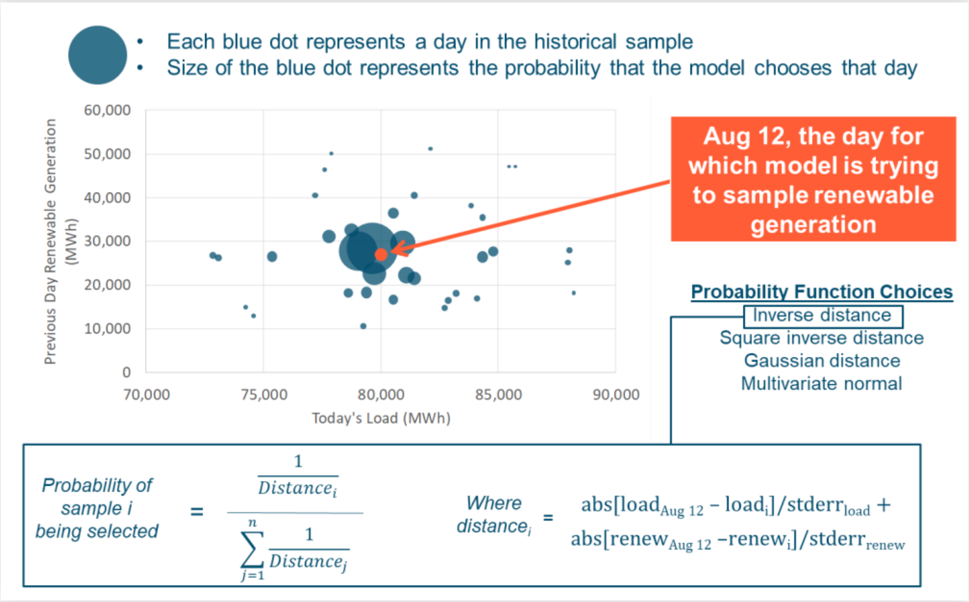
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data (i.e., years with available renewable data). For each day in the historical weather-informed load profile (1980-2019), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

- Season (+/- 15 days) - Probability is 1 inside this range and 0 outside of this range.

- Load - In summer peaking systems, high load days tend to have high solar output while in winter peaking systems, the opposite can be true.
- Previous Day's Renewable Generation - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 7-15.

Figure 7-15. Renewable Generation Profile Selection Process



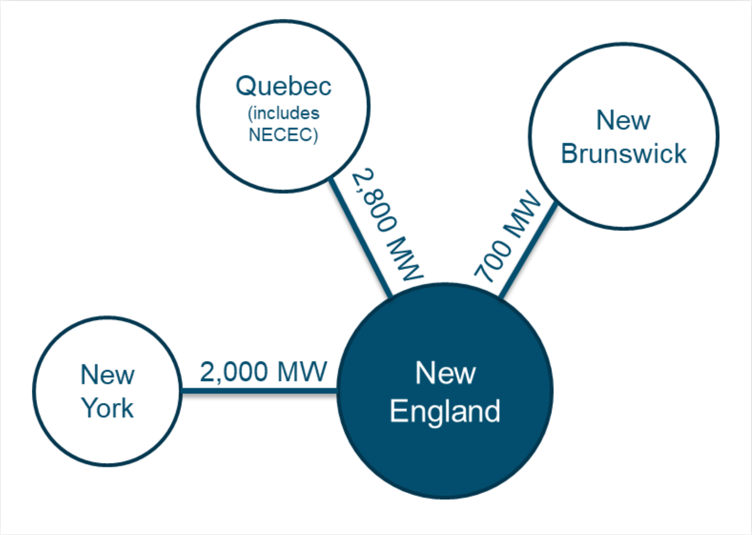
7.5 New England Capacity Expansion (RESOLVE) Model Assumptions

The following section describes certain additional components of RESOLVE methodology in greater detail and lists the technical assumptions used in the study (in addition to the information in Section 3.4).

7.5.1.1 Imports

The New England electricity system is modeled as a single load zone with electric transmission access to three external zones – New York, Quebec, and New Brunswick. This topology, shown in Figure 7-16, represents the major transmission connections into New England today. The line rating of these import/export lines is taken from the results of ISO-NE's latest forward capacity auction (for 2023-24 capacity commitment period). In addition, 1,200 MW of additional transmission to Quebec is added to reflect the New England Clean Energy Connect (NECEC), which is expected to come online in 2022 (1,090 MW of the total 1,200 MW is assumed firm for RECAP, as noted above).

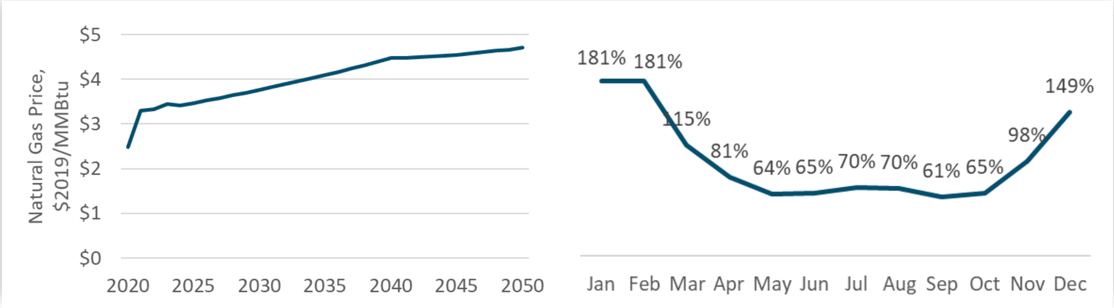
Figure 7-16. New England Baseline Transmission Topology in RESOLVE



7.5.1.2 Fuel Prices

Natural gas in New England has historically been priced via Algonquin gas pipeline and this trend is assumed to continue. The Algonquin hub natural gas price is based on future contracts in the short term (2021 - 30) and gas commodity projections by EIA in the long term (2040 – 50), linearly interpolating in the interim years. New England's winter gas pipeline constraints are reflected using higher natural gas prices in the winter months. Both of these trends are shown in Figure 7-17.

Figure 7-17. Assumed Natural Gas Price Forecast - Annual (left) and Monthly (right)



Data source: Algonquin natural gas future contracts (2021-30), EIA projections (2040 – 50), with linear interpolation for interim years.

Other fuels, such as coal, oil, and uranium are based on EIA commodity projections in both the short and long term. The cost of hydrogen is developed as described in Section 7.1.

7.5.1.3 Resource Potential

To meet the region's energy and capacity needs, RESOLVE selects from a range of resource options (Table 7-6). While some resources such as simple cycle gas turbines, combined cycle gas turbines, and lithium batteries are allowed to be built indefinitely (without a limit), there is a limit to solar, wind, hydro and nuclear additions (Table 7-6). These limits reflect both technical and practical considerations. As discussed in the main report body, solar is limited to the equivalent of 4% of farmland, and onshore wind is limited to the equivalent of 2% of forests and farmland. This results in 22 GW of solar potential and 10 GW of onshore wind potential in the region in the Base Case (though this assumption is relaxed in certain sensitivities). Further, the model can build up to 27 GW of distributed solar generation, which is based on the assumption that half of NREL's technical potential is available.

New England's 3.3 GW of nuclear capacity is currently its largest source of carbon-free power, producing over seven times as much carbon-free electricity as all the region's wind and solar combined. All nuclear generation in the region is set to retire during the analysis period. Total nuclear build (or license extensions or nuclear repowering) is limited to about 3.5 GW, roughly commensurate with today's nuclear capacity in the region.

Demand response provides up to 4.4 GW of daily flexible load in all hours in 2050. This represents EV charging load that can be shifted within the day. In addition, 740 MW of shed demand response is modeled for all years where load is curtailed during peak demand, reflecting ISO-NE near-term projections in the latest CELT report.

Table 7-6. Base Case Resource Availability for RESOLVE Candidate Resources

Candidate Resource Option	Resource Availability in RESOLVE Base Case	Description
Simple Cycle Gas Turbines	No limit	
Combined Cycle Gas Turbines	No limit	
Distributed Solar PV	27 GW	50% of NREL technical potential
Utility-Scale Solar PV	22 GW	Limited to 4% of farmland
Onshore Wind	10 GW	Limited to 2% of farm + forest land
Offshore Wind	280 GW	NREL technical potential
Li-ion Storage (4+ hour)	No limit	
Canadian Hydro Upgrades (Tier 1)	2.25 GW	Based on a Hydro-Quebec exploration study[gg]
Canadian Hydro New Impoundments (Tier 2)	2.25 GW	
Canadian Onshore Wind	4.5 GW	
Advanced Nuclear	3.5 GW	Limited to current nuclear capacity, which is expected to retire fully
Carbon Capture and Sequestration (CCS)	0 GW	No CCS is allowed in the base case but is addressed through sensitivity analysis

Note: Sensitivities on the above Base Case are provided in several sensitivities (e.g., relaxing/restricting land use and resource availability constraints).

7.5.1.4 Resource Costs

Most resource costs are obtained from public sources such as the NREL Annual Technology Baseline (2018 and 2019) and Lazard Levelized Cost of Storage (Version 5.0) for Lithium-ion storage. Canadian hydro costs are derived from empirical costs of past hydro projects. Annualized capital costs and levelized costs (Table 7-7) used in the analysis are obtained from a regional proforma model that accounts for project finance, tax payments, and regional labor and production factors.

The levelized costs of renewable resources shown in Table 7-7 are average values, shown for illustrative purposes. Renewable resources are represented in RESOLVE using a more detailed supply curve (Figure 3-7), which accounts for different qualities and interconnection costs of solar and wind sites. The renewable supply curve, an aggregation of hundreds of sites, is obtained from NREL's Regional Energy Deployment System (ReEDS) model.

[gg] New England's share is assumed to be 50% of total available resource to northeast US from Deep decarbonization in the Northeastern US and expanded coordination with Hydro-Quebec study. Available here

Table 7-7. Capital and Levelized Costs of RESOLVE Candidate Resources

Candidate Resources	Capital Cost ($2019/kW)		LCOE ($2019/MWh)		Source
	2020	2050	2020	2050	
Onshore Wind	$1,964	$1,282	$60	$41	NREL ATB 2018 w/ regional factors
Offshore Wind – Fixed	$3,604	$1,645	$86	$48	NREL ATB 2018 w/ regional factors
Offshore Wind – Floating	$4,964	$1,820	$129	$72	NREL ATB 2018 w/ regional factors
Solar PV	$1,468	$938	$52	$46	NREL ATB 2018 w/ regional factors
Distributed PV – Res	$3,286	$1,490	$137	$74	NREL ATB 2019 w/ regional factors
Distributed PV – Com	$2,283	$1,411	$94	$72	NREL ATB 2019 w/ regional factors
Canadian Wind	$1,964	$1,282	$65	$47	NREL ATB 2018 w/ regional factors
Canadian Hydro (tier 1)	$846	$846	n/a	n/a	Empirical Canadian hydro cost data
Canadian Hydro (tier 2)	$5,422	$5,422	n/a	n/a	Empirical Canadian hydro cost data
Li-ion Storage (energy) $/kWh	$251	$93	n/a	n/a	Lazard LCOS v5.0 study
Li-ion Storage (capacity)	$172	$64	n/a	n/a	Lazard LCOS v5.0 study
Natural Gas CC	$1,351	$1,192	n/a	n/a	NREL ATB 2019 w/ regional factors
Natural Gas CT (Peaker)	$927	$803	n/a	n/a	NREL ATB 2019 w/ regional factors
Gas CC w/ CCS (90% capture rate)	$2,573	$1,999	n/a	n/a	NREL ATB 2019 w/ regional factors, plus costs for transportation and storage based on E3 research
Advanced Nuclear	$7,414	$6,211	n/a	n/a	NREL ATB 2019 w/ regional factors

Note: The levelized costs shown for renewable resources are average values, with a more detailed supply curve accounting for different qualities and interconnection costs of solar and wind sites actually utilized within the model.

7.5.1.5 Additional Information on Transmission Requirements and Costs

Integrating significant quantities of new resources will require investments in new transmission. The model makes several assumptions regarding when and where new transmission will be required. These transmission assumptions are summarized in Table 7-8. As noted in the table, all new renewable projects require interconnection/spur line costs. We then model network upgrade costs once certain headroom thresholds are exceeded, with headroom available as follows:

- Local headroom is available for utility-scale solar up to 50% of 2050 peak (by state)
- Interstate headroom is available for onshore wind or utility-scale solar up to state-specific thresholds (see Table 7-8)
- Offshore wind is able to access up to 8 GW of existing headroom

Once headroom availability is used up, the model will require 345 kV lines. We note that the modeling assumes that co-locating storage resources at renewable project sites reduces the amount of new 345 kV backbone transmission capacity required to integrate onshore renewables. For every MW of onshore renewable resource (once headroom is exhausted), 0.6 MW of new 345 kV transmission is assumed. Offshore wind, however, has no transmission synergies with other resources and requires a MW of new transmission for every MW of new offshore wind. For distributed solar, no new transmission is assumed to be necessary to integrate the first 13.5 GW of distributed solar ("tier 1") resources. However, the second tier (the remaining potential of 13.5 GW) of distributed solar projects require additional 115 kV transmission.

Firm resources, such as gas turbines and energy storage resources, are assumed to not incur any additional transmission costs. The citing flexibility for these non-renewable resources enables efficient usage of existing and future transmission headroom resulting from resource retirements.

Table 7-8. Transmission Modeling for Renewable Integration in RESOLVE

Transmission voltage level	Qualified renewables	Details
Interconnection (spur line) – 230 kV	All renewable projects incur a spur line cost	Assumes distance from site to nearest bulk grid component, with incremental builds in a given location requiring transmission to further bulk grid locations
Network upgrade (backbone) – 345 kV	Required once local-serving renewable build threshold exceeded (50% of 2050 peak for utility-scale solar) and once remaining available interstate headroom is exhausted (utility-scale solar and onshore wind). Interstate headroom: - 800 MW for NH + VT - 4,000 MW each for CT, MA, RI - 8,000 MW for offshore wind	Interstate headroom based on Advisory Group input and historic flows on major pathways in New England as reported by ISO-NE. Cost based on interstate transmission distance to load center (Boston).
Distributed solar interconnection – 115 kV	Tier 2 distributed solar projects (triggered after 13.5 GW are built without transmission costs) incur 115 kV transmission costs	Fixed distance of 50 miles assumed

Table 7-9. Transmission Costs in RESOLVE

Transmission voltage level	Cost ($/MW-mile)	Source
Regional network upgrade (backbone) – 345 kV	$9,003	ISO-NE regional transmission studies[hh]
Quebec network upgrade (backbone) – 345 kV	$6,553	Average of Northern Pass and NECEC transmission projects[ii]
Interconnection (spur line) – 230 kV	Varies	Renewables in NREL ReEDS database have site-specific transmission costs[jj]
Distributed solar interconnection – 115 kV	$15,000	Estimates from MISO transmission costs[kk]

7.6 Detailed RESOLVE Results

7.6.1 Capacity and Generation by Model Year

The following tables provide detailed RESOLVE installed capacity and annual generation results for the modeled years over the analysis period (2025 – 50).

[hh] Taken from ISO-NE's system planning document on transmission development costs to integrate Maine wind here

[ii] NECEC and Northern Pass costs taken from MIT-CEEPR's Deep Decarbonization of the Northeastern US and the Role of Canadian Hydropower paper available here

[jj] jj NREL ReEDS documentation on how resource specific spur line costs are developed is available here

[kk] Transmission cost estimate guide for MISO is available here

Table 7-10. High Electrification Scenario Results: Total Installed Capacity

Total Installed Capacity (MW)	2025	2030	2035	2040	2045	2050
Existing Fossil	24,017	24,017	24,107	24,107	24,107	24,107
New CC/CT	-	1,879	3,781	6,033	8,966	9,713
Nuclear	3,472	2,163	3,472	3,472	3,472	3,472
Hydro	2,011	2,011	2,011	2,011	2,011	2,011
Biomass	702	702	702	702	702	702
Waste	541	541	541	541	541	541
Onshore Wind	4,544	4,544	6,058	7,879	7,879	7,879
Offshore Wind	-	4,138	5,200	8,446	13,386	21,863
Solar	8,202	11,535	11,866	14,958	23,263	23,263
Distributed Solar	3,577	4,150	4,150	9,825	13,350	13,350
Storage	1,795	3,991	5,648	8,159	10,919	15,017
DR	740	740	740	740	740	740
HQ Imports	2,800	2,800	4,064	5,050	5,050	5,050
NY Imports	2,000	2,000	2,000	2,000	2,000	2,000
NB Imports	700	700	700	700	700	700

Table 7-11. High Electrification Scenario Results: Annual Generation

Annual Generation (GWh)	2025	2030	2035	2040	2045	2050
Existing Fossil	44,481	29,673	11,820	3,637	329	5
New CC/CT	-	14,909	26,943	24,944	17,336	6,533
Nuclear	30,415	18,948	30,414	29,395	26,998	25,172
Hydro	5,242	6,019	5,808	5,594	5,530	5,364
Biomass	6,148	6,150	6,150	6,088	5,922	5,436
Waste	4,671	4,739	4,739	4,661	4,541	4,168
Onshore Wind	17,097	17,097	21,845	27,841	26,930	25,859
Offshore Wind	-	14,289	18,504	31,375	48,466	78,992
Solar	15,059	21,016	21,607	26,984	41,650	41,650
Distributed Solar	4,778	5,545	5,545	13,375	17,930	17,930
Storage	(1,332)	(711)	(960)	(596)	(1,334)	(1,551)
HQ Imports	4,965	16,897	25,560	27,894	25,386	21,021
NY Imports	7,343	7,343	7,343	7,343	7,343	7,343
NB Imports	1,116	1,753	2,821	2,949	2,410	1,139
Drop in Hydrogen	-	-	-	-	-	5,156
Generation	139,983	163,666	188,138	211,485	229,439	244,217

Table 7-12. High Fuels Scenario Results: Total Installed Capacity

Total Installed Capacity (MW)	2025	2030	2035	2040	2045	2050
Existing Fossil	22,919	22,919	21,563	21,563	21,563	21,563
New CC/CT	-	-	105	105	1,993	2,873
Nuclear	3,472	2,163	2,857	3,472	3,472	3,472
Hydro	2,011	2,011	2,011	2,011	2,011	2,011
Biomass	702	702	702	702	702	702
Waste	541	541	541	541	541	541
Onshore Wind	4,544	4,544	5,791	5,791	7,879	7,879
Offshore Wind	-	4,138	5,200	8,000	8,699	13,321
Solar	7,838	10,082	10,886	11,266	14,699	14,699
Distributed Solar	3,577	4,150	4,150	4,150	11,689	13,350
Storage	1,795	3,983	5,512	6,842	8,636	10,017
DR	740	740	740	740	740	740
HQ Imports	2,800	2,800	3,012	4,926	5,050	5,050
NY Imports	2,000	2,000	2,000	2,000	2,000	2,000
NB Imports	700	700	700	700	700	700

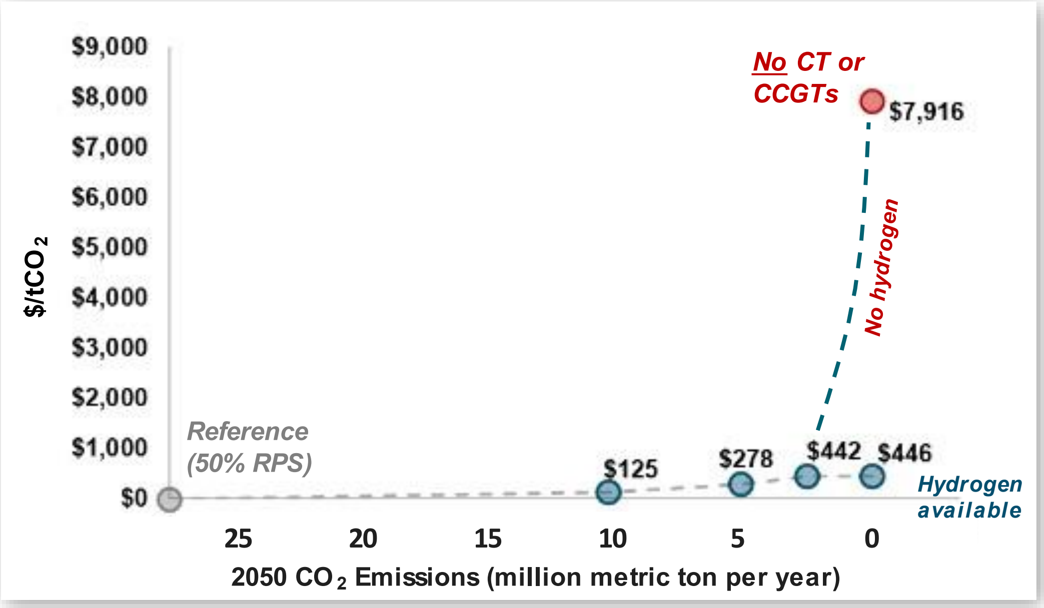
Table 7-13. High Fuels Scenario Results: Annual Generation

Annual Generation (GWh)	2025	2030	2035	2040	2045	2050
Existing Fossil	42,853	32,818	19,627	11,510	3,096	1,227
New CC/CT	-	9,910	15,851	13,524	12,152	2,981
Nuclear	30,415	18,948	25,028	30,415	27,945	26,323
Hydro	5,130	5,994	5,822	5,607	5,441	5,287
Biomass	6,141	6,150	6,150	6,150	5,995	5,689
Waste	4,672	4,739	4,739	4,739	4,609	4,360
Onshore Wind	17,097	17,097	20,964	20,964	27,638	27,324
Offshore Wind	-	14,289	18,504	29,612	32,230	48,518
Solar	14,406	18,424	19,856	20,544	26,519	26,519
Distributed Solar	4,778	5,545	5,545	5,545	15,784	17,930
Storage	(1,399)	(610)	(985)	(818)	(667)	(654)
HQ Imports	4,764	14,133	20,335	27,813	25,997	23,414
NY Imports	7,343	7,343	7,343	7,343	7,343	7,343
NB Imports	1,100	1,668	3,090	2,959	2,472	1,906
Drop in Hydrogen	-	-	-	-	-	6,872
Generation	137,301	156,446	171,509	185,906	196,552	205,038

7.6.2 Marginal Cost of Carbon Abatement

The following figure provides marginal costs of carbon abatement under the High Electrification scenarios for this study. The grey curve reflects our base set of assumptions under High Electrification loads, in which zero-carbon fuel (hydrogen) is available. The red dot, alternately, reflects the case with no combustion-based generation is allowed. With hydrogen available, the marginal abatement costs in blue flatten out in the $440s, reflecting the switch from burning a MWh of natural gas to one of hydrogen. The red dot, alternately, reflects abating the remaining 2.5 tons using all renewables (i.e., no combustion-based generation burning hydrogen).

Figure 7-18. Marginal Carbon Abatement Costs ($/ton) (High Electrification Loads)



7.7 Additional Detail on Regional Innovation Priority Areas and Assets

7.7.1 Dispatchable Low-Carbon Electricity

7.7.1.1 Natural Gas-Fired Generation with Carbon Capture

Post-combustion carbon capture and sequestration on natural gas combined cycle plants (NGCC-CCS) is approaching commercial readiness, but ongoing innovation—in both the technology and business models—will help drive projects into deployment. Several successful megawatt-scale tests have taken place. Research continues on improved CO_2-absorbing solvents, construction methods, and alternatives to amine scrubbing such as CO_2 separation with membranes. Designing plants to use modular parts, open designs, and interoperable solvents can also foster greater competition in engineering, procurement, and construction, allowing for reductions in plant cost.[51] New England would also have to deal with finding disposition options for the captured CO_2, as the geology for carbon sequestration (e.g., oil and gas wells, saline formations) is not present in the region.

In the longer term, designing power plants from the ground up for carbon capture can create more efficient and cost-effective designs that integrate capture and generation. New fossil and renewable gas-driven thermal power cycles—such as combustion of gas in a pure oxygen environment (oxycombustion) and use of supercritical CO_2 as a working fluid—can offer significant reductions in capital cost and parasitic load associated with carbon capture systems while increasing plant flexibility.

7.7.1.2 Modular and Advanced Nuclear Reactors

Advanced nuclear reactors encompass a wide range of devices, of which small modular reactors (NSMRs) are closest to commercialization and are the most likely candidates for New England by midcentury. NSMRs are miniaturized light-water fission reactors designed for off-site manufacturing and rapid assembly into arrays at a power plant site. NSMR designers hope to build reactors in factories, leveraging economies of scale in manufacturing rather than in power plant size. Final construction would involve installing multiple containment vessels that come with both the reactors and shielding pre-installed, simplifying engineering and execution. NSMRs can be valuable for electrical generation, cogeneration, or providing purely thermal loads (e.g. for hydrogen production or industry). Demonstration-scale reactors are already under construction.

Governments and private companies have also invested significant resources into the development of radically new reactor types, moving beyond the light-water reactors used today. Key research goals include passive safety features, lower nuclear waste production, and reduced capital costs. Molten salt reactors, high-temperature gas reactors, pebble bed reactors, and liquid metal-cooled reactors are some posited designs in various stages of R&D and small-scale demonstration.[52] Nuclear fusion remains a perennial hope for clean power, though net energy gains remain elusive and commercial power generation is decades away at best. Fusion research takes place both in startups and in government-funded "big science" projects around the world.[53,54]

7.7.1.3 Innovation Assets: Firm Low-Carbon Generation

Despite its strength in energy storage and hydrogen research, New England has relatively few firms and laboratories studying low-carbon fossil generation. Federally funded academic research includes several projects that could increase the efficiency of fossil-fired plants by allowing higher operating temperatures and more efficient heat exchange.[55] MIT conducts some research on carbon capture, use, and storage.[56] MIT spinoff Infinite Cooling has technology that radically decreases the water consumption for all steam-driven power plants, a technology that could be valuable for low-carbon generation.[57]

New England has several assets related to advanced nuclear development. MIT, home to a world-class nuclear engineering department, operates a 6-MW fission test reactor and an experimental "Tokamak" fusion device in Cambridge.[58] The department has also received ARPA-E funding for research on materials for advanced reactors. Worcester Polytechnic Institute has also received research funding from the Nuclear Regulatory Commission and offers a certificate in nuclear engineering.[59] A few nuclear energy startups are based in the Boston area, including Commonwealth Fusion Systems, and Yellowstone Energy.

7.7.1.4 Long-Duration Energy Storage

Long-duration energy storage (LDES) encompasses a broad range of technologies that vary by mechanism, cost, discharge duration, and maturity. While there is no technical definition of "long duration," a key distinction is whether a technology is best suited to shifting loads within a day or to managing day or week-long imbalances between energy supply and demand. The physical assets providing storage capacity can take the form of tanks for liquids, injectable subsurface geologic formations for storing gases, dammed reservoirs for water, and masses of earth for thermal storage. ARPA-E[ll] defines long-duration storage as technologies that can discharge for between 10 and 100 hours at their maximum rated power. To achieve seasonal energy storage, even longer discharge durations would be required.

Many technologies with numerous variations have potential for long-duration energy storage. Flow batteries are a broad class of devices that shuttle fluids between reservoirs by way of a chemical reactor. A reversible electrochemical reaction of these fluids in the reactor charges or discharges the battery. Variants use zinc, vanadium, sulfur, and other chemicals. Several American companies are developing flow batteries, including a Boston-based firm that plans to demonstrate a 1MW, 150-hour prototype in Minnesota by 2023.[60,61]

Compressed air energy storage (CAES) forces pressurized air into an underground aquifer, salt formation, or mined cavern, then releases it through turbines or turboexpanders to generate electricity. In the two existing full-scale CAES plants, compressed air is fed directly into a gas-fired combustion turbine in order to boost the turbine output, storing energy but still generating carbon emissions.[62] Zero-emission "isothermal" CAES plants are also under development using air-only turboexpanders instead of combustion turbines. The Department of Energy funded an isothermal CAES pilot in New Hampshire from 2011 to 2015.[63] In areas like New England with limited subsurface formations suitable for CAES, liquid air storage presents an alternative. A 50MW liquid air pilot project in Vermont was announced in 2019 with a claimed 70% round-trip efficiency.[64] That project has only 8 hours' discharge at full capacity, but longer durations are possible.

Thermal storage systems use heat pumps or resistance to heat a large thermal mass, such as graphite, molten salt, or a section of ground, then convert the heat to electricity to discharge. High-temperature thermal storage's end-to-end efficiency is currently too low for standalone electricity storage, though the technology finds use in concentrated solar power plants. Several startups aim to address this issue; none have yet advanced beyond the R&D stage.[65,66] Low-temperature thermal storage uses the ground as a thermal mass. A German company has piloted a 600°C "hot rock" storage system with 45% charge-discharge efficiency.[67] A Danish company is demonstrating a 1MW, 24-hour storage system collocated with a wind farm.[68] These low-temperature storage systems offer efficiencies above 90% when directly supplying thermal loads for space heating or industry.

Hydrogen can also function as a long-duration energy storage medium. H_2 generated from electrolysis in times of low electricity prices could be consumed in a fuel cell or turbine in times of high electricity prices.

[ll] ARPA-E (Advanced Research Projects Agency – Energy) is a division of the US Department of Energy that funds research, development, and demonstration work on emerging energy technologies in both academia and the private sector.

Where geological formations that can store hydrogen exist, standalone hydrogen-based electricity storage facilities are a possibility. At least two developers in Utah are exploring this possibility.[69,70] However, no such formations exist in New England. This means that while hydrogen could well be combusted to provide load-following electricity in New England, it is unlikely that electrolysis and storage would be collocated with generators in standalone energy storage units. Hydrogen-related technologies are discussed further in the "Renewable Fuels" section below.

7.7.1.5 Innovation Assets: Long-Duration Energy Storage

New England has significant innovation resources relevant to long-duration storage. For example, one of the MIT Energy Initiative's Low-Carbon Energy Centers focuses on energy storage and MIT is part of the Joint Center for Energy Storage Research (JCESR), a DOE Innovation Hub based at Argonne National Laboratory.[71,72] New England is also home to many companies in the energy storage space, each with its own research and development capabilities. These include large multinationals like MA-based General Electric and CT-based Praxair, mid-sized companies like MA-based battery firm NEC, and numerous startups.[73]

In 2020 there were 15 ARPA-E grantees conducting energy storage research in New England.[74] Many study long-duration electricity storage. Somerville, MA-based Form Energy has developed a flow battery for multi-day energy storage. The technology, which could offer installed capital costs below $20/kWh of capacity, will be demonstrated by 2023 in a configuration with 150-hour maximum discharge capacity.[75] Hampton, NH-based Brayton Energy is developing a thermal energy storage system that uses both molten salt and chilled hydrocarbons. The academic research on which their project is based projected marginal costs of storage capacity between $10 and $15 per kWh.[76] ARPA-E grantees at Harvard and at the United Technologies Research Center are developing other flow battery designs.

Electric utilities in New England are also on the cutting edge of storage deployment, with first-of-a-kind programs for deployment of utility-owned distributed storage being undertaken by Green Mountain Power in Vermont and Liberty Utilities in New Hampshire.[77] New England's policy environment is encouraging for storage innovation, with storage-related policies in five of the six states (all except Rhode Island).[78] Massachusetts leads the way, with a 1-GW procurement mandate by 2025, a "Clean Peak Standard" introduced in 2020, and the Massachusetts Energy Storage Initiative within the state Department of Energy Resources.[79,80] Market innovation, however, will be needed alongside technological innovation, since electricity markets may under-value long-term storage.[81]

New England has already deployed some demonstrations of new long-duration storage technologies. SustainX (now defunct) operated a 1.5MW CAES pilot in New Hampshire from 2013 to 2015.[82] There are some installed thermal storage projects in New England. Most use produce ice or heat ceramic bricks as the storage medium.[83] However, these projects are small (under 1 MW) and not configured for long-duration storage. Highview Power Storage is developing a 50MW/400MWh (8 hour) liquid air energy storage system in Vermont.[84]

7.7.2 Renewable Fuels

Renewable fuels are chemical fuels, some with the same composition as fossil fuels, that are generated with clean electricity or from other low-carbon sources. Fuels can be stored inexpensively in bulk, making them suitable for long-duration energy storage, backup generation, space heating backup, and other applications that enhance energy system reliability. Fuels are also well-suited to applications in industrial process heat and weight-sensitive transport that are difficult to electrify. This report's high-fuels modeling scenario quantifies the role that these fuels could play in New England's future energy system. Despite this promise, renewable fuels value chains are in very early stages of development. Challenges include costs, feedstock availability, and availability of compatible end-use devices.

The fuel types discussed below – hydrogen, biofuels, and renewably synthesized hydrocarbon fuels – are best suited to slightly different applications. Hydrogen could serve as a cost-effective grid energy storage medium, transport fuel, or industrial fuel. However, it is incompatible with existing end-use machinery like industrial furnaces and jet engines. In contrast, methane and liquid fuels synthesized from green hydrogen and captured carbon are entirely compatible with existing machinery. However, their higher cost and energy-intensive production relative to hydrogen may limit them to applications like aviation where the properties of fossil fuels appear indispensable. Biofuels can fill either niche: more expensive "drop-in" liquid fuels could provide carbon-neutral alternatives to gasoline, jet fuel, and fuel oil, while waste biomass-derived fuels like landfill methane could be inexpensive enough for use in power generation. The pace of innovation and cost reduction in each area (both in fuel production and end-use machinery) will determine which fuels eventually dominate which applications.

7.7.2.1 Biofuels

Biofuels refer to chemical fuels derived from plant matter and organic wastes. Since all the carbon contained in biomass feedstocks originated in the atmosphere, use of biofuels is typically considered carbon neutral, though combustion can still produce other pollutants and the energy required for fertilizer, harvesting and other ancillary processes has non-zero emissions. Some biofuels can be mixed in limited quantities into conventional fossil fuels; other "drop-in" fuels are entirely compatible with existing engines and other end-use devices.

The main objective of biofuels research is the production of cost-effective drop-in liquid fuels from low-cost feedstocks. Oil majors, national labs, startups, and universities are among those researching numerous biofuel production pathways.[85] Cellulosic biofuels (derived from stalks, leaves, and wood) and algae-derived biofuels are two major areas of research. Pilot-scale biorefineries, many supported by the Department of Energy, have produced heating oil, gasoline, diesel, kerosene, and jet fuel from these sources, but prices are still high.[86]

7.7.2.2 Innovation Assets: Biofuels

Biofuels are an exciting area of research in New England, with Massachusetts and Maine seeing the most activity. Innovation begins in the region's universities, many of which have strong biology and bioengineering departments. Scientists at UMass Amherst are developing special strains of drought-tolerant crops optimized for biofuel production.[87] Teams at Harvard, MIT, and UMass Amherst are working on bioreactors that can convert hydrogen and CO_2 into fuels.[88,89] Teams at the Woods Hole Oceanographic Institution in MA and at the University of New England in ME have received ARPA-E funding to design ocean-based seaweed farms for biofuel production.[90] The University of Maine's Forest Bioproducts Research Institute, discussed below, has conducted decades of research on producing fuels from the pulp and lumber industries' waste streams. Teams at UMass Lowell have recently worked on converting wet biowaste and sawdust into liquid fuels.[91,92]

Biofuel startups are a subset of a vibrant biotech ecosystem in the region and especially near Boston. Agrivida, a Boston-based company, develops enzymes that can break down cellulosic biomass for fuel production.[93] Ginkgo Bioworks and GreenLight Biosciences, both based in Boston, is working on bioreactors for upgrading methane into liquid fuels.[94,95] Several other startups in Massachusetts over the past 15 years have attempted to bring advanced biofuels to market at scale, though none have yet succeeded.[96,97]

Maine has already seen several efforts to develop cellulosic biofuels from woody feedstocks, including academic research, private-sector demonstrations, and government support for innovation. Following the closure of many pulp mills in the state, companies and policymakers have recognized a need to diversify the state's forest products industry.[98] Old Town, ME, has seen over a decade's worth of public-private collaboration on biofuels. In 2007, faculty at the University of Maine and mill owner Red Shield Environmental secured funding from the Department of Energy to build a biofuel demonstration system in Old Town, ME.[99] The funding also helped construct a multipurpose testbed for biofuel production technologies, where corporate and academic researchers could test their ideas on shared equipment.[100]

Red Shield Environmental ended its commercialization trial in 2012 and sold the Old Town plant in 2015.[101,102] Massachusetts-based Biofine, another company interested in biofuel production, purchased the plant and the pilot equipment. A partnership between Biofine and the University of Maine's Forest Bioproducts Research Institute (FBRI), which had worked on the original Old Town testbed, helped to create the new University of Maine Technology Research Center on Old Town plant site. The center has allowed the FBRI to conduct numerous research projects since 2017, expanding knowledge on biofuel production from woody materials.[103] Recent work has moved beyond ethanol and butanol to produce crude oil from woody biomass.[104] Through collaboration with FBRI, Biofine has developed a forest product-based heating oil substitute. The company received $750,000 from the Maine Technology Institute in 2019, becoming one of two grantees in a government program to diversify the state's forest products industry.[105] The money will go towards construction of a larger biorefinery in Bucksport, ME to produce renewable heating oil.

7.7.2.3 Hydrogen

Hydrogen is an appealing low-carbon fuel because it has a high energy content on a mass basis, releases no CO_2 when combusted, and can be produced with only water and electricity. It is potentially relevant in the power sector, for peaking electricity; in the transport sector, for long-distance and weight-critical applications; and in the industrial sector, for high-temperature process heat. Despite this promise, innovation is critical across all levels of the hydrogen value chain – production, transport, and consumption – to make hydrogen a functional and cost-effective energy carrier.

Priority innovation areas for hydrogen include:

- Application of CCS to steam methane reforming
- Lower cost electrolyzer production
- Integration of hydrogen production with low-cost renewables or nuclear power
- Long-distance bulk transportation
- Lower-cost fuel cells
- Specialized turbines for hydrogen-fueled power production

7.7.2.4 Innovation Assets: Hydrogen

New England has strong fuel cell-related innovation capacity, with Connecticut a particular hotspot. The Department of Energy's 2016 *State of the States: Fuel Cells in America* report listed Connecticut as one of the "Top 3 Fuel Cell States" in the country, alongside the much larger and populous New York and California.[106] Connecticut ranked third in the nation for fuel cell-related patents between 2002 and 2015, and in 2016 roughly 30% of the United States' fuel cell-related jobs were located there.[107] Most companies currently focus on natural gas or propane fuel cells. Doosan Fuel Cell America, a subsidiary of a South Korean conglomerate, has its headquarters, R&D center, and fuel cell factory in Windsor. Among its projects is a 20MW backup system for a data center in New Britain, CT, which will be one of the world's largest fuel cell microgrids when completed.[108] FuelCell Energy, based in Danbury, CT, has developed fuel cell power systems as far afield as California and Korea. Other significant fuel cell companies based in the state include Proton Onsite and Infinity Fuel Cell and Hydrogen.

Connecticut has supported its home-grown fuel cell industry in several ways, resulting in various natural gas and propane fuel cell installations. Between 2013 and 2017, the state Department of Energy and Environmental Protection (DEEP) administered a microgrid grant and loan program, enabling the installation of fuel cells at police stations, fire stations, schools, and other public facilities in the towns of Parkville and Woodbridge, as well as at the University of Bridgeport.[109] In 2018 DEEP launched a grant program for offshore wind, fuel cell, and anaerobic digestion projects in support of the state's clean energy goals. Winners included four fuel cell projects totaling 52MW.[110] All stationary fuel cell installations are valued in the state's renewable portfolio standard, with credit values dependent on the fuel used.[111]

The region also has some innovation capacity in other steps of the hydrogen value chain. Proton OnSite is a globally competitive PEM electrolyzer manufacturer. In 2015 the company offered the world's first megawatt-scale PEM device; it also supplied electrolyzers for a hydrogen bus network in China.[112] Formerly named Proton Energy Systems, in 2017 the firm's industrial and utility-scale division merged with NEL Hydrogen.[113] Proton OnSite and its associated R&D capacity remain in Wallingford, CT. Giner Inc. of Newton, MA, also produces electrolyzers, though they are currently marketed for laboratories, defense, and other specialized applications.[114] General Electric is headquartered in Boston, but its turbine research campus (where its hydrogen turbines are developed) is in upstate New York.[115]

7.7.2.5 Power-to-X for Drop-In Fuels

Power-to-X refers to any system that generates hydrogen or hydrocarbon fuels from renewable electricity and feedstocks. Green hydrogen, discussed in the previous section, is an example. Combining electrolyzed hydrogen and captured carbon dioxide can, in principle, generate hydrocarbon fuels like crude oil, gasoline, and natural gas. The advantage of such fuels is that their production is carbon-neutral and they are compatible with existing transmission, distribution, and consumption systems. However, production of hydrocarbons from CO_2 and H_2 is energy-intensive, and costs are currently far too high to compete with fossil fuels. Affordable hydrogen electrolysis and carbon capture—neither of which is yet a reality—are prerequisites for cost-competitive synthetic fuels of this kind.

Current research, which has reached the demonstration stage, has mostly focused on power-to-methane. Synthesis of more complex hydrocarbon fuels is also a possibility, though costs would be higher and conversion efficiencies lower. Still, the technology might be relevant to applications like aviation where energy-dense liquid fuels are likely to be irreplaceable. While technically feasible, power-to-liquids technology is very far from commercial readiness and the potential for increased electricity demands may prove challenging in the context of such demand increases from other sectors of the economy modeled in this study.

7.7.2.6 Innovation Assets: Power-to-X

Research activity on power-to-methane and power-to-liquids is relatively sparse in New England. No commercial-scale private-sector projects have taken place in the New England to date.[116] Since hydrogen is a feedstock for all other power-to-X fuels, New England companies' research on PEM electrolyzers and other hydrogen systems (discussed above) is valuable in this area as well. Universities' bioengineering and chemical engineering departments could be valuable assets in a future research push.

Some academic labs and startups in the region have begun to explore this space. Hartford-based Skyre Inc. develops devices to produce methanol, an alternative (non-drop-in) liquid fuel, from captured carbon dioxide.[117] Danbury, CT-based FuelCell Energy and Waltham, MA-based Giner Inc. are both developing power-to-ammonia systems.[118] Ammonia, while not a drop-in fuel, is an energy-dense liquid with applications to grid storage and possibly maritime transport. Insofar as ammonia is used in chemical production, carbon-neutral ammonia could also help address a hard-to-abate sector. Giner is developing an electrolytic ammonia production system, while FuelCell Energy is building a reversible electrolyzer/fuel cell device.

Several groups, including researchers at UMass Amherst, Harvard, and MIT are also investigating biological pathways for upgrading methane and hydrogen to liquid fuels.[119,120] At least two companies are working to commercialize biological methane upgraders.[121,122] Though these systems are biofuels in the sense of using microorganisms to perform chemical reactions, they could use synthetic methane, electrolyzed hydrogen, and/or captured CO_2 as feedstocks.

7.7.3 Hard-to-Decarbonize Sectors

7.7.3.1 Non-CO_2 Emissions: Methane and Substitutes for Ozone-Depleting Substances

Substitutes for ozone-depleting substances—used across all economic sectors for refrigeration, air conditioning, aerosols, and solvents—make up the majority of non-energy emissions in the region but have few avenues for decarbonization. ODS substitutes can have over 1,000 times the global warming potential of carbon dioxide over a 100-year period.[123] In Massachusetts in 2017, ODS substitutes accounted for 4.4% of the state's emissions.[124] Though some low-GWP refrigerants exist, including ammonia, CO_2, and some hydrocarbons, all have drawbacks like lower efficiency, toxicity, or flammability.[125] The development of low-GWP ODS substitutes is a priority for the Department of Energy and a subject of research in universities, national labs, and industry.

Another significant component of non-combustion emissions in New England is methane, mostly leaks from natural gas infrastructure, but also from other sources such as landfills, wastewater treatment plants, and livestock. The methods for methane abatement vary by source (leak detection and repair for natural gas systems; waste diversion for landfills; capture or combustion for wastewater treatment), and innovation is likely happen in regions with larger hydrocarbon production or agriculture sectors. New England can be proactive, however, about implementing the solutions that already exist and driving demand for innovation elsewhere.

7.7.3.2 Carbon Capture and Sequestration

Several cross-cutting tools, each the subject of current innovation, could find use across multiple hard-to-decarbonize sectors. CCS can allow the decarbonization of stationary sources without modifications to end use devices or fuel consumption. CCS via amine scrubbing has been demonstrated at scale by multiple companies, though cost reductions through optimization and alternate technologies are both possible.[126] In industries—such as cement, pulp and paper, or chemical manufacturing—that emit CO_2 from non-combustion chemical processes that are essential to manufacturing a product, CCS may be the only practical option. As mentioned above, however, sequestration may prove difficult given New England's unsuitable geology.

7.7.3.3 Difficult-to-Electrify Sectors

Emissions abatement will also be difficult to achieve in industries that require high-temperature process heat. More efficient high-temperature industrial heat pumps, which deliver 2-4 times as much thermal energy to a given process as they consume in electricity, could also lower the cost of process heat electrification. Offering high efficiencies at temperatures above 100°C, which would allow the generation of low-pressure steam, is a principal objective of industrial heat pump research.[127]

Renewable fuels, discussed in the previous section, could be useful in these industrial sectors, as for building heating in rural areas and those requiring backup heat, and in segments of the transportation sector (e.g., aviation, maritime transport, and long-haul trucking).

7.7.3.4 Innovation Assets: Hard-to-Decarbonize Sectors

Since industries (and other hard-to-abate sectors) in New England use equipment sourced from around the world, innovation beyond the region's borders is essential. Actors in New England have several options to support this work. They can continue to support the development of cross-cutting technologies like alternative fuels by New England-based researchers. They can enact policies that generate demand for low-emission equipment, driving distant companies to invest in product development. They can also support the site-specific engineering work required to reconfigure fossil-fueled industrial systems into zero-emission ones.

7.7.4 Carbon Dioxide Removal

7.7.4.1 Technology Innovation

CDR solutions can be deployed immediately and can make significant progress towards meeting net-zero goals. Innovation, however, could increase the options for CDR as the region approaches midcentury, reducing costs and mitigating concerns about land use.

Two of the most prominent CDR approaches which require innovation, direct air capture (DAC) and bioenergy with CCS (BECCS), present problems for New England due to the lack of CO_2 sequestration options. They do provide many benefits in terms of scalability; BECCS, in particular, appeals in New England because of the existing combustion of biomass in industries like pulp and paper. Other innovative CDR approaches could take advantage of New England's existing strengths and make natural approaches more efficient or scalable. New forestry techniques, for example, could include genetically engineered trees with greater carbon removal abilities, green tree burial that prevents decomposition, or the use of wood to create new long-lived products such as buildings. The nascent field of ocean-based CDR, which includes techniques to capture CO_2 from seawater as well as boost the massive natural CDR capabilities of the oceans, could also be a good fit with New England's historical strengths in both private marine industries and maritime research.

7.7.4.2 Innovation Assets: CDR

Since carbon dioxide removal is a young area of research with limited near-term business prospects, innovation assets are sparser than in more developed fields. Few, if any, of the handful of companies exploring the space are based in New England. Nonetheless, scientists at New England's universities and other research institutes have expertise relevant to developing and assessing novel CDR technologies, and some are already conducting relevant research. With appropriate funding, more resources from earth science and engineering departments and laboratories could be mobilized to create better CDR pathways.

New England has several institutions with expertise in oceans' role in the carbon cycle, including university earth science departments and dedicated oceanographic institutions. Some have studied ocean-based paths to carbon dioxide removal. Researchers at the Bigelow Laboratory in Maine have studied carbon sequestration by phytoplankton.[128] A professor at Dartmouth recently received a Guggenheim fellowship to study ocean fertilization for CO_2 removal.[129] MIT has also studied ocean fertilization.[130] These technologies are in very early stages of development, in New England and elsewhere. Work to date in New England has focused on modeling and feasibility assessment, not demonstration.

Though New England has strong research capabilities in bioengineering, they have not yet been applied to carbon dioxide removal. None of the grantees for ARPA-E's ROOTS program, which aims to develop carbon sequestering crop cultivars, are in New England. Nonetheless, Massachusetts in particular is a hotbed for biotech development, including various agriculture startups.[131,132] Academic and private-sector expertise in technologies like gene editing could also prove useful for crop-based CDR research.

The main technological limitation on bioenergy with carbon capture is the readiness of cost-effective carbon capture technology. Despite some relevant research at New England's universities (e.g. MIT), CCS innovation is dominated by global heavy equipment firms. The lack of easy carbon sequestration sites in New England makes it a poor site for first-of-a-kind BECCS demonstration facilities.

The direct air capture space is currently very small, with no companies based in New England. The founder of Carbon Engineering, a Canada-based DAC company, is a professor of applied physics at Harvard.[133] MIT also conducts some basic research on DAC.[134]

New England's universities also have the resources to support much more research into carbon dioxide removal. For artificially enhanced natural CDR, earth sciences departments will be valuable assets; for technological CDR, engineering departments. Key topics of research include developing the required technology (e.g. for DAC) and assessing whether known technologies are actually effective (e.g. for ocean based CDR, green log burial, deep soil inversion, and others). This research on effectiveness is essential before non-mechanical CDR pathways' contributions can be quantified, valued by policies, and applied to New England's emissions targets.

7.7.4.3 Policy and Business Model Innovation

Despite the potential for CDR in New England, the region will face numerous challenges to deployment. Most (if not all) pathways will require a comprehensive policy and regulatory framework to maximize the potential for CDR and provide greater certainty to investors and project developers that CDR presents a viable opportunity in New England. This will include the need for standardized protocols to measure and verify carbon storage and permanence, especially for natural CDR techniques. State governments in New England will need to clarify whether (and which types of) CDR can be pursued to help the region meet its climate targets. Policy and business model innovation can also drive market formation for CDR; while some frameworks for valuing DAC have been implemented elsewhere in the country, and natural methods have benefitted from voluntary carbon markets, there are virtually no avenues to monetize the carbon benefit of most CDR approaches.

[1] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/rank_use_capita.html&sid=US

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