2025 Regional System Plan

DECEMBER 8, 2025

Preface

ISO New England Inc. (the ISO or ISO-NE) is the nonprofit corporation responsible for performing a unique and critical mission: through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity. The planning process includes the periodic preparation of a Regional System Plan (RSP) in accordance with the ISO's Open Access Transmission Tariff (OATT) and other parts of the Transmission, Markets, and Services Tariff ("tariff"), approved by the Federal Energy Regulatory Commission (FERC). RSPs meet the tariff requirements by summarizing planning activities, including the following:

- Forecasts of annual energy use and peak loads (i.e., the demand for electricity) for a 10-year planning horizon and the need for resources (i.e., capacity).
- Information about the amounts, locations, and characteristics of market responses (e.g., generation or demand resources or elective transmission upgrades (ETUs)) that can meet the defined system needs — systemwide and in specific areas.
- Descriptions of regional transmission projects that meet identified needs summarized in the RSP Project List. The ISO updates the list several times each year, and it includes information on project status and cost estimates.

RSPs also must summarize the ISO's coordination of its system plans with those of neighboring grids, the results of economic studies of the New England power system, and information that can inform the design of the regional wholesale electricity markets. In addition to these requirements, RSPs identify other actions taken by the ISO, state officials, regional policymakers, participating transmission owners, New England Power Pool (NEPOOL) members, market participants, and other stakeholders to meet or modify the needs of the system.

RSPs are not comprehensive plans of the region's power system. They serve as technical resources for policymakers, industry participants, and other interested stakeholders – offering an informational snapshot of the many aspects of the power grid's operation and future at one moment in time. Additional information about the New England power system is available on the ISO's website. In addition to this RSP, the ISO's Annual Work Plan is an important resource listing the ISO's anchor projects and notable initiatives, and showcasing the kinds of forward-thinking endeavors needed to meet the challenges of decarbonization and the region's transition to clean energy.

The ISO is instrumental in ensuring the New England power grid remains reliable as it undergoes this transformation, but states, consumers, and industry stakeholders also play crucial roles. Collaboration among all key players is essential, and the ISO will continue to operate in this spirit as the energy transition unfolds.

The regional system planning process in New England is open, transparent, and reflects advisory input from regional stakeholders, particularly attendees of the Planning Advisory Committee (PAC), according to the requirements specified in the OATT. PAC meetings are not public hearings, but the PAC is open to all entities interested in regional system planning activities in New England, and it provides detailed and up-to-date information about significant changes in system planning. The ISO appreciates the robust stakeholder input that makes this report possible.

The *2025 Regional System Plan* (RSP25) and the regional system planning process identify the region's electricity needs and plans for meeting these needs for 2025 through 2034. RSP25 updates the *2023 Regional System Plan* (RSP23) by discussing study proposals, scopes of work, assumptions, draft and final study results, and other materials. RSP25 also identifies key electric power system issues the region faces and how they might be addressed.

Through the planning process, the ISO demonstrates compliance with all planning criteria and regulatory requirements. As required by the OATT Attachment K, the ISO New England Board of Directors has approved this *2025 Regional System Plan*.

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The 2025 Regional System Plan

Driven by a combination of policy goals, economic factors, and technological advancements, New England's power system is on a path toward far-reaching changes in how much electricity the region's homes and businesses use, and when they use it. At the same time, the fleet of resources needed to satisfy rising levels of demand is evolving significantly. As a result, New England's transmission system will see needs for upgrades and expansion in the decades ahead.

RSP25 provides an update on the ISO's latest load forecasts and a summary of new supply resources proposed in the region. The report also covers current approaches and results of the transmission planning process, as well as updates regarding resource adequacy. It offers an overview of recent economic studies, which explore how the changing resource mix can meet reliability requirements through the power system's ongoing transition.

Each section of RSP25 focuses on a different component of system planning. This executive summary offers highlights from each section.

Section One

Regional Drivers and Coordination

Overviews federal and state policies affecting the power grid

Summarizes current environmental regulations governing the region's energy resources

Section Two

Forecasts of New England's Peak Demand and Annual Electricity Use

Outlines this year's projection of regional energy consumption over the 10-year planning horizon

Section Three

Transmission System Performance, Upgrades and Needs Assessments

Provides an overview of the regional transmission system and the status of various upgrades

Section Four

Resource Interconnection and Integration

Summarizes the quantity and types of resources that currently have proposals in the ISO's interconnection queue

Section Five

Resource Adequacy

Identifies the quantity of resources the regional system will need to maintain reliability over the planning horizon

Section Six

Economic Studies

Details current needs assessments that simulate possible evolutionary changes to the grid

State emissions goals drive electrification and changes in demand.

State policy goals continue to target deep reductions in carbon dioxide (CO_2) emissions, as well as increases in renewable energy. These public policies, detailed in Section 1, are driving change in the regional power system.

One expected result is a marked growth in the electrification of heating and transportation, which will increase electric demand. The ISO's annual Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) projects an increase of more than 11% in annual electric energy use on the New England grid between 2025 and 2034. Additional energy production is required to meet this growth.

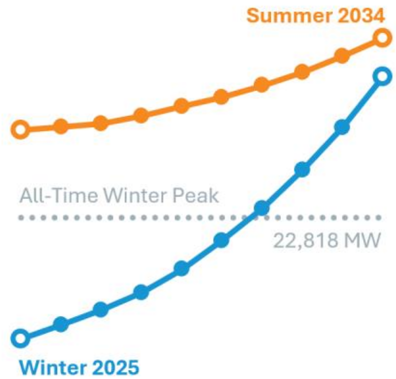
State policy goals will also affect the seasonality of net peak demand — the highest amount of electricity demand our resource fleet and transmission system must meet at the same time. New England currently experiences peak demand for electricity in the summer. But the 2025-2034 CELT Report forecasts that by 2034, New England's winter and summer peaks will begin to converge. Over the 10-year forecast, peak demand is expected to increase from 24,803 MW to 26,897 MW in summer and from 20,056 MW to 26,020 MW in winter. Electrification of heating systems and transportation will drive the increases in winter demand.

For the first time, the 2025-2034 CELT incorporates hourly projections (instead of annual or seasonal profiles) for all aspects of the forecast, including for heat pumps and electric vehicles (EVs). This innovation allows for more realistic projections of how growth in the adoption of these technologies will impact the grid. Though this year's edition of the CELT projects a slight slowing in EV adoption compared to previous reports, it still forecasts significant growth in the coming decade.

Load forecasting methodologies require continuous improvement to ensure accuracy through a rapidly evolving picture of the future, and the ISO anticipates further refinements to the CELT's forecasting approach in next year's edition.

In This Report

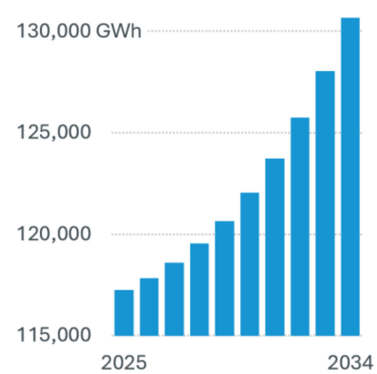
According to ISO forecasts, by 2034, New England's winter peak will approach levels typically seen in the summer:



In winter 2024-2025, electric heat pumps drove **less than 1%** of peak demand

By winter 2034-2035, electric heat pumps will drive **over 18%** of peak winter demand

Annual electric energy usage in New England will grow from **117,262 GWh** in 2025 to **130,665 GWh** in 2034:



► **Learn more in Section 2.**

Other changes to the power system include shifting demand patterns at times of very *low* electricity usage. On April 20, 2025 — Easter Sunday — sunny skies and mild temperatures drove demand for grid electricity in New England to its lowest level ever. Power system demand fell to 5,318 MW. It was the fourth year in a row the grid notched such a milestone. Driving this trend is power from behind-the-meter (BTM) solar photovoltaic (PV) systems, which reduce demand on the grid but are essentially invisible to ISO system operators and cannot respond to dispatch instructions from the ISO control room.

In some areas, distributed PV development is already straining the limits of the existing distribution infrastructure, and the ISO's PV forecast suggests sustained growth over the 10-year forecast horizon. Accurate projections of how these resources will grow are vital to maintaining reliability over the next decade and beyond. As BTM PV increases, its limited visibility and dispatchability will present operational challenges, and its effect in lowering overall demand will require modifications to a transmission system that was not designed to operate at such low load levels. Recent transmission needs assessments of Boston and Connecticut identified the need to add reactive devices to help mitigate high transmission voltages at very low levels of system load.

Increases in behind-the-meter solar over the next decade will drive minimum loads to record lows. BTM PV helps meet the region's energy needs with low-cost, emissions-free electricity, but can introduce operational challenges.

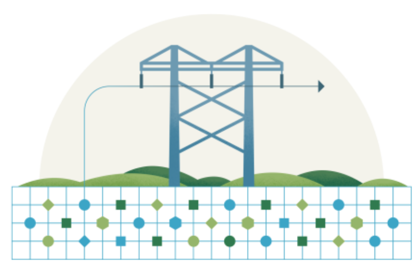
► **Learn more in Section 2.**

Regional collaboration powers investment in longer-term transmission needs.

Longer-term investment in the region's high-voltage transmission system is a key planning focus. At the direction of the New England States Committee on Electricity (NESCOE), in spring 2025 the ISO issued a request for proposals (RFP) to address longer-term transmission needs. Proposals in response to the RFP are due in September 2025. Although the schedule following these submittals is subject to change, after evaluation by the ISO, the ISO or NESCOE may select a preferred solution as early as September 2026.

The 2025 Longer-Term Transmission Planning Request for Proposals aims to increase transfer levels in Maine and accommodate the interconnection of **1,200 MW** of land-based wind to the regional power grid.

► **Learn more in Section 3.**



The goal of the RFP is to upgrade the transmission system between northern Maine, where land-based wind generation is expected to increase, and the more populous regions of southern New England, where demand for electricity is highest. Much of the framework of the RFP is drawn from the ISO's landmark 2050 Transmission Study, published in early

2024. Follow-up analysis focusing on offshore wind interconnection was published earlier this year.

Changes to the interconnection process improve integration of new resources.

Accommodating more solar, wind, and battery storage is a top priority for the interconnection study process the ISO manages. Before a new resource can connect to the New England grid, the ISO conducts a series of technical studies to ensure the resource can receive service reliably. The increase in smaller resource technologies in recent years has contributed to a significant increase in proposals. The composition of resources in the interconnection queue has also evolved, with battery storage forming an increasing share of proposed new resources.

The ISO's implementation of FERC's Orders No. 2023 and 2023-A in spring 2025 introduced a first-ready, first-served cluster study process. The change will speed up queue processing through more collective analysis, improved timelines, and more accurate modeling of inverter-based resources. Two upcoming cluster studies, the Transitional CNRC Group Study and the Order No. 2023 Transitional Cluster Study, both expected in 2025, represent the first such studies under this more efficient process.

Resource adequacy forecast drives progress in capacity market reforms.

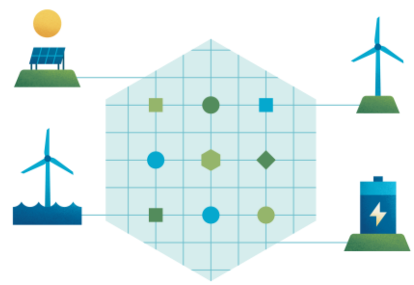
Through commitments secured via the existing Forward Capacity Market (FCM) construct, New England has locked in capacity to meet its resource adequacy needs through June 1, 2028. The 2025-2034 CELT indicates the region will have sufficient resources to meet demand through 2033. This finding is bolstered by the U.S. Department of Energy's July 2025 *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*. The energy department's analysis projects that New England will maintain resource adequacy through 2030.

However, the following factors could contribute to resource inadequacy in the 2030s:

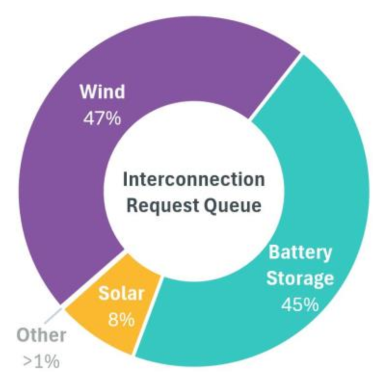
- insufficient entry of new resources
- unexpected load growth and/or resource retirements

The *2050 Transmission Study: Offshore Wind Analysis* examined 50 coastal substations as candidates for connecting offshore wind or other resources.

► **Learn more in Section 3.**



Implementation of a new cluster study process will help alleviate interconnection backlogs and provide more accurate modeling of battery storage, wind, and solar resources, which account for most proposals in the interconnection request queue as of July 1, 2025:



► **Learn more in Section 4.**

- a shortfall in fuel needed to power various resources or insufficient fuel infrastructure, described as energy inadequacy. (This is different from resource inadequacy, or a shortage in the resources themselves.)

Slower than anticipated load growth may partially offset any delays in the buildout of new resources. During the past decade, the region experienced slow wholesale load growth driven by state investments in energy efficiency and BTM PV. Conversely, a rapid acceleration in load growth, whether from electrification, data centers or other sources, could heighten reliability risks.

The generators most at risk of retirement are primarily large oil-fired resources with low capacity factors.[1] However, consideration of retiring resources is only one element of resource adequacy considerations; energy adequacy is also key. Ensuring the availability of a diverse supply of resources to provide energy during a broad range of system conditions is a critical component of resource adequacy.

The increase in weather-sensitive resources like wind and solar will require a more seasonally focused capacity market. For 18 years, the FCM's annual auctions secured commitments from energy resources three years in advance. The ISO's proposed Capacity Auction Reforms will change the way capacity is secured for the commitment period beginning June 1, 2028. Work is underway to design a new prompt/seasonal capacity market aligned with the region's evolving resource mix. The ISO has targeted 2026 for completion of the market's design.

The prompt component means auctions take place within months, not years, of the delivery period, improving the overall quality of auction outcomes by incorporating more accurate information on projected supply and demand conditions. The seasonal component means auctions will be held ahead of winter and summer, allowing the region to procure capacity that can better meet differing seasonal risks, including gas constraints that challenge winter operations in New England.

The market will also include a new accreditation methodology that measures the marginal contribution of different resource

The ISO's **Capacity Auction Reforms** will help ensure reliability as the region's resource mix becomes more weather dependent.

The new prompt auction will take place shortly before each capacity commitment period, instead of three years in advance.

The new capacity commitment period will be split into two seasons, instead of one year.

The reformed capacity market will be updated to better reflect how evolving resources contribute to resource adequacy.

► **Learn more in Section 5.**

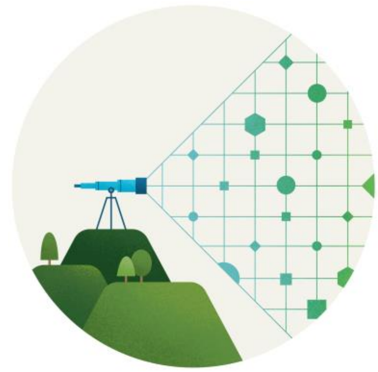
[1] Capacity factor is the ratio between the electrical energy a generating unit produced for a certain period to the electrical energy it could have produced at full operation during the same period.

types to ensure the overall resource portfolio can satisfy energy supply requirements under current reliability criteria.[2] To this end, existing average historic performance-based accreditation processes will be replaced with accreditation requirements that accurately capture the marginal energy contribution of participating resources during the seasonal periods of highest reliability risk. These rules will recognize an individual resource's supply capability and limitations in serving the system demand based on availability and performance (e.g., forced/maintenance outages), output variability (e.g., intermittent power resources), and fuel/energy constraints (e.g., gas/oil energy constraints during winter). The modeling will also incorporate the most material correlations among resource types and between supply and demand, such as a negative correlation between gas supply and electric power demand during winter.

Developing an innovative new capacity market is just one of the projects the ISO is undertaking to ensure the design of its wholesale electricity markets evolves in keeping with the power system's increasing complexity. The ISO's Wholesale Markets Project Plan, updated twice each year, provides an overview of market improvements under consideration and development.

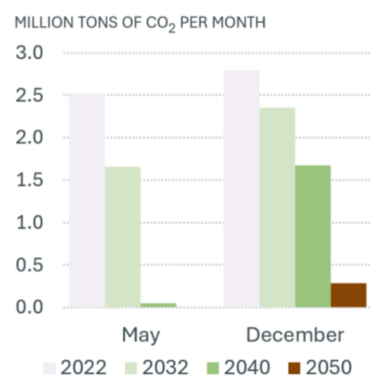
Modeling the energy transition illuminates paths to the future.

The ISO has made significant strides in meeting the challenges and harnessing the opportunities of the clean energy transition, and this work continues. The ISO's forward-looking economic studies explore potential resource mixes and buildout costs over the 10-year planning timeframe and beyond. Recent improvements in the study process were piloted in the Economic Planning for the Clean Energy Transition (EPCET) study, published in 2024. EPCET identifies trends the region should consider to ensure power system reliability, progress toward state decarbonization goals, and informed decision-making about efficient spending and investment.



By 2050, the region will need a power system around **three times** its current capacity to maintain reliability while accommodating electrification and meeting state emissions goals.

Results from the ISO's 2024 EPCET study show the potential for spring to decarbonize long before winter.



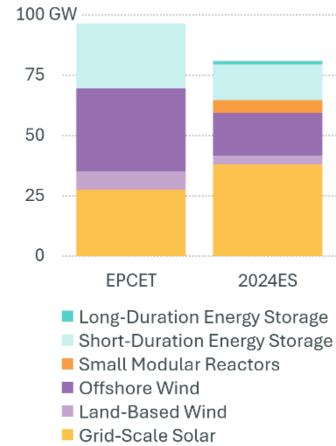
▶ **Learn more in Section 6.**

[2] Current reliability criteria are such that the loss-of-load expectation (LOLE) of disconnecting non interruptible customers due to resource deficiencies is not more than 0.1 day each year.

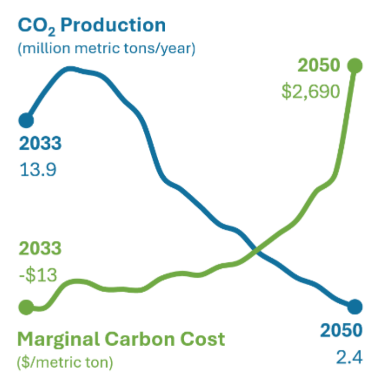
EPCET's results highlight how the states' pursuit of policy goals might result in large increases in variability of supply and demand. By 2050, peak demand could vary 50% between a mild and a severe winter, driven by expected increases in electrification. Resources highly dependent on weather, like wind and solar, will drive a similar increase in the year-to-year variability of electricity supply. More overall variability will mean many resources required to meet peak demand may run for less than 1% of the year.

The study also highlighted the seasonality of emissions reductions. Together, wind and solar typically produce more energy in fall and spring — when demand for electricity is lower — than they do in winter. So, increasing production from these non-emitting resources could mean that spring fully decarbonizes many years before winter. This seasonality indicates that as the years pass, newly built renewable resources will have a decreasing impact on cutting emissions, driving higher costs for reducing CO_2, particularly between 2040 and 2050. New zero-carbon technologies like small modular nuclear reactors (SMRs) and synthetic natural gas (SNG) may emerge as alternatives.

Building on the work of EPCET and improvements to the study process, the ISO's 2024 Economic Study models more future scenarios and actionable analysis than ever before. Modeling includes SMRs and 100-hour batteries as part of its base case for the first time, and highlights diversity in the resource mix and consideration of trade-offs as keys to reducing emissions for the least cost. The 2024 Economic Study is also the first to include the new System Efficiency Needs Scenario, which establishes a clear trigger for certain kinds of transmission upgrades.



Results from the 2024 Economic Study show that including technologies like small modular reactors and long-duration energy storage in the 2050 grid could reduce the size of the clean energy buildout by almost 17%.



The 2024 Economic Study model shows decarbonization costs escalating beyond an 85% reduction in emissions from 1990 levels.

► **Learn more in Section 6.**

Aging and limited infrastructure presents challenges.

As the grid transitions and modernizes, it must do so in the context of an aging generation fleet and transmission system. In many cases, infrastructure components are decades old. Some existing resources are nearing retirement, and the Capacity Auction Reforms project will also include a resource deactivation process. While some resource deactivation is expected, large capacity removals will need to be offset by the entry of new resources — especially if system demand grows as projected.

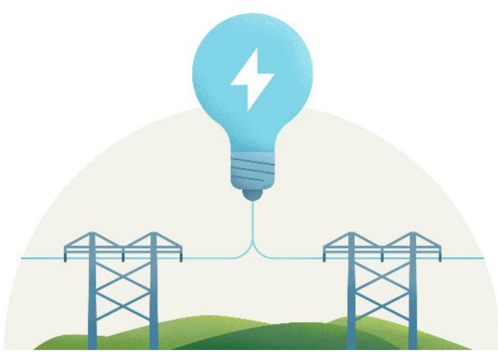
During periods of extended cold weather, New England has long been challenged by limited gas infrastructure — as well as our location at the end of the pipeline — to meet the combined peak demand from heating customers and power generation. At such times, the region depends on oil-fired resources with large quantities of fuel already on site. However, many of these units are at risk of retirement: they run infrequently, are less efficient, and are nearing the end of their economic life (most date to the 1970s). Evaluating the possibility of a regional energy shortfall during extreme weather is therefore crucial.

In collaboration with the Electric Power Research Institute, the ISO developed a robust energy adequacy assessment framework called the Probabilistic Energy Adequacy Tool (PEAT). Initial PEAT-based energy adequacy studies of 2027 and 2032 found the energy shortfall risk is manageable in the near-term, with an increasing risk profile over the long-term. However, this assessment assumes the market will respond with new resources to meet projected demand increases associated with electrification; that offshore wind resources and associated transmission will be built; and that the gas system will remain reliable under the modeled scenarios.

PEAT assessments are now aiding the development of the Regional Energy Shortfall Threshold (REST). Using magnitude and duration thresholds, REST will allow the region to determine its tolerance for energy shortfalls during extreme events in a manner that, assuming a reliable gas system, considers both reliability and cost.

The transmission system faces its own age-related challenges, and a growing number of asset condition projects are needed to refurbish deteriorating transmission facilities. Historically, the ISO has had limited involvement in the Transmission Owners' (TO) asset condition projects. The ISO is supportive of additional oversight and recognizes the benefits of a robust process and independent review.

Following preliminary discussions with the states and the TO sector regarding asset condition project oversight, the ISO is exploring how to take on an advisory role as an Asset Condition Reviewer. After assessing and developing a preliminary framework, the ISO plans to bring a proposal to the stakeholder community for discussion and feedback.



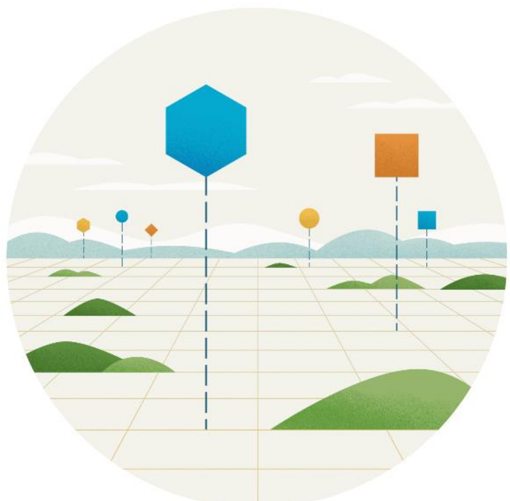
New transmission technologies offer possibilities for inverter-based resource integration.

The ISO continues to evolve and improve the integration and oversight of inverter-based resources, such as grid-scale solar installations, to the regional power system. As the proportion of these technologies versus traditional synchronous resources increases, the ability of the grid to respond to system disturbances may change. Such changes must be understood and reflected within planning and operating studies, and the ISO continues to improve its methodologies in this area.

The ISO and the region remain at the technical forefront of successfully integrating wind, solar, storage, demand response, and high-voltage direct current and flexible alternating current transmission system devices. Technological developments affecting regional system planning involve integrating grid-transformation equipment, improving operator awareness and system modeling, and using phasor measurement units. Following reliability incidents in the US and overseas, the industry expects increasing regulatory requirements, such as pending NERC standards requiring benchmarking and field-verification of inverter performance.

On June 18, 2025, the ISO convened a day-long conference focused on Grid Enhancing Technologies (GETs), where equipment vendors and transmission owners provided updates on developments in these areas. GETs are already considered in the ISO's planning process, and continued discussion helps build on earlier work and provide information on newer technologies.

Conclusion and Future Outlook



As New England's grid operator, the ISO plays a vital role in reliably planning and operating the grid as state policy drives the region's transition to clean energy. However, the challenges ahead are significant.

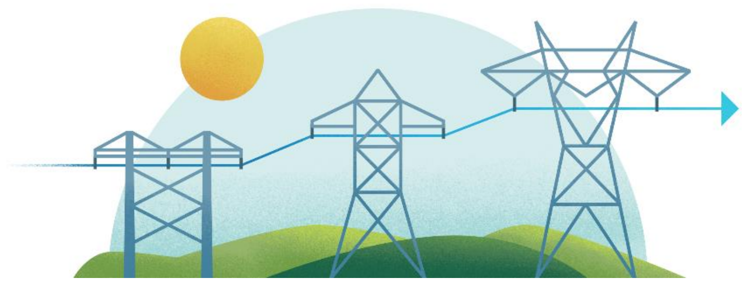
As detailed in this executive summary, various conditions precipitated by the energy transition will create unprecedented shifts in the operation of the New England power grid. The ISO's studies consistently show the need for significant transmission development and sufficient dispatchable resources that can run independent of weather conditions.

How quickly will the region electrify and how quickly will demand grow? Will New England see large data center additions like other parts of the country? Will offshore wind continue to face headwinds, and will alternative generation sources emerge to ensure resource and energy adequacy? How quickly will technology evolve? How will the region maintain infrastructure that may be seldom used, but will be critical to fill energy gaps over days or weeks when weather-dependent resources are not available? Will changes in state or federal policy affect the overall pace of change?

These questions and more guide the ISO's approach to managing the engineering and economic realities the region must contend with as the transition continues. Other variables are also at play, from the pace of resource retirements to rising costs, supply chain issues, and siting challenges that could slow or threaten the build-out of new energy infrastructure. Some variables will fall within the scope of the ISO's responsibilities and authority. Others will fall under state authority. Others will involve global economic forces.

ISO New England is committed to working with the region to plan, prepare, and execute changes to meet the challenges ahead.

Section 1
Regional Drivers and Coordination



The ISO's External Affairs department engages with public officials, policymakers, regulators, consumer representatives, and environmental agencies regarding important initiatives affecting the energy sector. These initiatives include projects and key study areas aimed at developing and integrating new technologies, improving operating and planning procedures, and updating the wholesale markets to enhance system reliability. Stakeholders include the New England Conference of Public Utilities Commissioners (NECPUC), NESCOE, and the Consumer Liaison Group (CLG), among others.

Various policies and programs at the federal, state, and multistate levels affect wholesale electricity markets and transmission, specifically regarding the type and location of resources and transmission infrastructure, and the timing of updates to those resources and infrastructure. Additionally, policies of many of the six New England states aim to encourage electrification of heating and transportation, which is projected to have impacts on total load and load profiles throughout the coming decade and beyond. Federal efforts by FERC, the US Department of Energy (DOE), Congress, and the White House also have implications for the ISO and the sector. The ISO closely monitors both federal and state activity to inform various stakeholder and study processes. The information in this report is a summary of key policies the ISO is tracking as of August 10, 2025; it is not a full accounting of the federal and state policies that have an impact on the regional power system.

1.1 ISO New England Collaboration with New England States on Policy Goals

The ISO engages with market participants and state entities, including NESCOE, to assess the future of the regional power system in light of state energy and environmental laws and explore potential paths to a sustainable clean energy grid that is reliable and efficient.

The ISO also provides technical assistance to the New England states, including answers to questions about the Tariff, qualitative feedback on project proposals, and interconnection procedures.

In 2024, the ISO finalized the EPCET study. Described in greater detail in Section 6, EPCET explored the operational, engineering, and economic challenges the region would need to address to support the New England states' commitment to reduce carbon emissions over the next several decades. Also in 2024, the ISO completed the 2050 Transmission Study, described in greater detail in Section 1.3.1 and Section 3, which identified investments needed through the middle of the century to ensure bulk power system reliability as the clean energy transition unfolds. These studies provide critical information and analysis to policymakers and regulators pursuing current clean energy and climate policy objectives.

1.2 Incorporating Federal Regulatory and Policy Actions

A number of recent FERC efforts have targeted improvements to both the generator interconnection process and electric transmission planning and development. FERC issued notices of major rulemakings and final rules, described below, that will change various aspects of planning and transmission development.

On July 28, 2023, FERC issued Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, the final rule adopting many of the reforms to the interconnection process proposed in the commission's original Notice of Proposed Rulemaking (NOPR). See Section 4.2 for further discussion of Order No. 2023.

On May 13, 2024, FERC issued Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920. This landmark rule sets new requirements for how organizations like the ISO conduct long-term planning for regional transmission facilities and determine how to pay for them. The intent is to ensure the identification of more efficient or cost-effective regional transmission solutions. Many elements of Order No. 1920 align with New England's innovative Longer-Term Transmission Planning Phase 2 framework accepted by FERC in July 2024, described further in Section 3.

On March 21, 2024, FERC announced a new Federal and State Current Issues Collaborative (Collaborative) as a forum to discuss "cross-jurisdictional issues relevant to FERC and state utility commissions." Comprised of the five FERC Commissioners and 10 state commissioner representatives, the Collaborative's first focus is gas-electric coordination. ISO New England President and CEO Gordon van Welie participated in the second meeting of the Collaborative in April 2025, which focused on gas-electric coordination and gas storage. In July 2025, the Collaborative hosted its third meeting in Boston, which focused on ISO/RTO governance and resource adequacy.

Since taking office in January 2025, President Trump has issued more than a dozen executive actions focused on energy and environmental issues, including offshore wind development, Inflation Reduction Act (IRA) funding disbursement, oil and gas production, and siting and permitting.

Two such examples are the January 20, 2025 Executive Orders on Unleashing American Energy and Declaring a National Energy Emergency. Among other things, the first instructed federal agencies to "immediately pause the disbursement of funds appropriated through the IRA." The second includes language instructing federal agencies to "identify and exercise any emergency authorities" to facilitate the "leasing, siting, production, transportation, refining, and generation of domestic energy resources." On the same day, President Trump also issued a presidential proclamation halting the permitting and leasing of new or renewed wind projects on federal lands and waters. Since that proclamation was issued, the Trump Administration has announced several additional actions targeting offshore wind, including the rescission of all offshore wind energy areas on the U.S. outer continental shelf.

In July 2025, President Trump signed into law a reconciliation package, the *One Big Beautiful Bill*. The bill makes significant changes to components of the IRA, including phasing out various tax credits that have supported the development of clean energy technologies, the adoption of clean vehicles, and the deployment of energy efficiency technologies. Additionally, the bill rescinds unobligated IRA funding for several DOE grants and programs focused on transmission and planning. This includes funding for the Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis Program; the Transmission Facility Financing Program; and grants to Facilitate the Siting of Interstate Electricity Transmission Lines.

1.3 Coordination among the New England States

Each of the New England states is actively involved in the ISO's regional planning process, individually and through NESCOE. NESCOE is governed by a board of managers appointed by the governors of the six New England states and is active in matters related to resource adequacy and system planning. NESCOE's forward-looking priorities are highlighted in its annual report. NESCOE and individual state representatives are active in regional stakeholder processes and discussions about the ISO's Annual Work Plan.

The ISO also works collaboratively with NECPUC, the New England governors' offices, state energy offices, and the states' consumer advocates, providing monthly updates on regional stakeholder discussions regarding regional planning processes and the wholesale electricity markets.[3]

1.3.1 Longer-Term Transmission Planning Process

In 2020, NESCOE's New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid recommended that the ISO work with stakeholders to incorporate a comprehensive longer-term regional transmission planning (LTTP) process in its system planning efforts. The first phase of the LTTP tariff changes, accepted by FERC in February 2022, created the longer-term transmission study process, which helped initiate the ISO's landmark 2050 Transmission Study. This study, the first of its kind for New England, informed stakeholders of the amount and type of transmission infrastructure necessary to provide reliable, cost-effective energy through the clean energy transition, driven by 2050 state policy goals.

Accepted by FERC in July 2024, the second phase of LTTP tariff changes created a new process to implement transmission system upgrades based on longer-term transmission studies. As part of this process, in March 2025, the ISO issued the first LTTP RFP, detailed further in Section 3. The RFP is designed to address longer-term needs informed by the 2050 Transmission Study, as identified by NESCOE in its final request letter of December 2024.

1.3.2 Department of Energy Funding

In 2024, the US Department of Energy awarded the New England states $389 million in Grid Innovation Program funding to enable the interconnection of new resources and deploy longer-duration energy storage. The project was selected for funding by the Biden Administration, but the

[3] Most state-appointed consumer advocates are members of NEPOOL.

contract was not finalized before the change in presidential administration. The ISO served as a technical advisor to the states as they developed their funding application.

1.3.3 Northern Maine Renewable Energy Development Program

Maine legislation enacted in 2021 directed the Maine Public Utilities Commission (PUC) to conduct an RFP for generation in northern Maine, and a transmission line to connect that generation to the ISO system. While the PUC had conditionally selected projects resulting from the RFP, it ultimately terminated the solicitation due to contract issues. The PUC has the authority to reissue this procurement, and in April 2025, issued a request for information (RFI) that includes consideration of ways a subsequent procurement might interact with ISO processes, such as the LTTP RFP and compliance with FERC Order No. 2023.

1.4 Individual State Initiatives, Activities, and Policies

The New England states work together to identify, discuss, and address energy issues of common interests, but each state also has a unique set of energy policy objectives and goals. This section briefly discusses Renewable Portfolio Standards (RPS) and carbon reduction policies and summarizes additional actions taken by the individual New England states related to regional system planning. Many of the New England states pursue initiatives that support reduced energy costs, accelerate electrification of heating and transportation, and advance the adoption of renewable energy generation. This section reviews current RPS guidelines, and highlights state-by-state changes in energy procurement processes and incentive programs since RSP23. It is not a comprehensive review of all enacted state policies and initiatives.

1.4.1 Renewable Portfolio Standards

To encourage the development of renewable energy resources, certain states have enacted RPSs, which require electricity providers (electric distribution companies and competitive suppliers) to serve a minimum percentage of their retail load using renewable energy. All six New England states have RPS requirements and goals, expressed as a percentage of retail electric sales, with varying definitions of renewable resources.

1.4.2 Connecticut

In 2025, Connecticut lawmakers passed a wide-ranging energy bill that affects electric rates, utility regulation, and related state agencies. It includes a requirement for transmission companies to include grid-enhancing technologies (GETs) in transmission applications to the Connecticut Siting Council and establishes a preference for GETs solutions. Additional provisions address demand response and time-of-use rates, a demand response pilot program, advanced nuclear reactors and nuclear energy procurements, standard service procurements, storage proceedings, and a new electric system efficiency goal.

In 2024, Connecticut Governor Lamont signed into law a bill that amended the state's procurement authority. Future nuclear energy procurement will require participation and cost-sharing from at least two other states. Additionally, the maximum allowed contract length for future offshore wind was increased from 20 to 30 years if the solicitation is coordinated with at least one other state.

In December 2024, the Connecticut Department of Energy and Environmental Protection (DEEP) announced the selection of a 200 MW energy storage project under its 2022 storage solicitation. DEEP continues to explore potential procurement opportunities in 2025.[4]

1.4.3 Maine

Legislation enacted in June 2025 updates Maine's RPS, increasing the 2040 requirement to 90 percent of retail electricity sales from renewable resources plus an additional 10 percent from a newly established clean resource category. The existing RPS requirement of 80 percent from renewable resources by 2030 remains.

Other legislation enacted in June 2025 will establish the Maine Governor's Energy Office (GEO) as a cabinet-level Department of Energy Resources and provide authority for the Department to issue competitive solicitations, including for renewable and clean resources beginning in January 2026.

Existing law provides Maine with the authority to issue a number of procurements, in addition to the authority described above and the Northern Maine Renewable Energy Development Program described in Section 1.3.3. A law passed in 2023 directs the GEO to design a procurement structure to meet the statutory goal to procure up to 3,000 MW of offshore wind by 2040. The PUC will review the proposed solicitation structure and, if approved, authorize the issuance of an RFP.

In October 2024, the US Bureau of Ocean Energy Management (BOEM) held a lease sale for the commercial offshore wind leasing area in the Gulf of Maine, resulting in two provisional winners on four lease areas. Additionally, in August 2024, BOEM issued to Maine the first floating offshore wind energy research lease in the country. However, federal actions, including those described in Section 1.2, create uncertainty for the development of offshore wind on these lease areas.

In December 2024, the GEO submitted a recommendation to the Maine PUC to procure up to 200 MW of energy storage for Maine. The Maine PUC is directed to review the program recommendation and determine whether they will issue a solicitation.

In 2023 the Maine PUC authorized a solicitation for renewable energy contracts. The PUC issued the initial round of this solicitation in September 2024; however, no contracts were awarded. In July 2025, the Maine PUC issued another solicitation, with a preference for projects located on contaminated lands, and those that minimize development on forested lands and farmland that is not contaminated.

In July 2024, following a multi-year public stakeholder initiative prompted by legislation enacted in 2022, the Maine PUC issued an order identifying priorities for state utility integrated grid plans to address. In response, Maine utilities are developing a holistic grid plan that will assist in the cost-effective transition to a clean, affordable, and reliable electric grid. The order directs utilities to file their plans with the PUC in January 2026.

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[4] On July 25, 2025, the Connecticut Department of Energy and Environmental Protection released a Request for Information seeking expressions of interest from potential project developers for zero carbon resources. CT General Statutes– Sec. 16A-3A 2025 Integrated Resources Plan Request for Information.

1.4.4 Massachusetts

As authorized by the legislature, the Massachusetts Department of Energy Resources (DOER) is continuing efforts to secure offshore wind resources for the Commonwealth. In August 2023, DOER and the electric distribution companies (EDCs) jointly issued an RFP for the Commonwealth's fourth — and largest — offshore wind solicitation to date, seeking to procure up to 3,600 MW of offshore wind. Following an agreement among Massachusetts, Connecticut, and Rhode Island to collaborate on offshore wind projects, the RFP became part of a multi-state procurement, resulting in a collective procurement authority of up to 6,000 MW. In September 2024, Massachusetts selected SouthCoast Wind (1,087 MW), New England Wind 1 (791 MW), and Vineyard Wind 2 (800 MW) from the bids received. Rhode Island selected the remaining 200 MW from SouthCoast Wind, and Connecticut declined to make a selection. Vineyard Wind 2 later withdrew their project from negotiations, citing the lack of a buyer for the remaining 400 MW of the 1,200 MW project. Completion of contract negotiations for SouthCoast Wind and New England Wind 1 is expected by December 31, 2025. Due to these ongoing negotiations and uncertainty at the federal level, DOER notified the DPU in August 2025 that DOER and the EDCs do not anticipate submitting a draft RFP for their fifth offshore wind solicitation until at least 2026.

Also in 2024, the Massachusetts legislature passed *An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers* (2024 Climate Act). Under the new law, large clean energy infrastructure facilities such as electric transmission, battery energy storage systems, and clean energy generation will apply for a Consolidated Permit from the Massachusetts Energy Facilities Siting Board. The Consolidated Permit will include one approval decision for all state and local permits, which must be decided within a 15-month deadline. If no decision is made by this deadline, the Consolidated Permit will be automatically approved. Small clean energy infrastructure facilities will be subject to Consolidated Local Permitting, whereby municipalities issue a single decision within 12 months for all local permits, or the local permits are automatically approved. The applicant for a small project may also request Siting Board issuance of all necessary state permits in a single decision (Consolidated State Permit), which is also subject to a mandatory 12-month deadline. The law also establishes a single appeals process, whereby Siting Board decisions on all consolidated permit matters go directly to the state Supreme Judicial Court.

The 2024 Climate Act further authorizes the state to issue a solicitation for energy storage, expands tax incentives for offshore wind development, creates new restrictions for natural gas expansion, and requires that electric transmission and distribution companies first consider hardware or software alternatives, such as grid enhancing technologies, over building new infrastructure, among other provisions.

On July 31, 2025, DOER and the EDCs released the first solicitation for energy storage under Section 83E. The EDCs seek to procure environmental attributes produced by transmission-connected mid-duration energy storage systems (defined as an energy storage system capable of dispatching energy at its full rated capacity for a period equal to or greater than 4 hours and up to 10 hours) up to a maximum capacity of approximately 1,500 MW.

1.4.5 New Hampshire

As authorized by the legislature, New Hampshire's Department of Energy (DOE) is exploring future applications for nuclear energy technologies. As of 2024, a new statute requires the DOE to open an investigative proceeding should a generating resource be forced into premature retirement due to external regulatory requirements. It also provides an option for the state's Attorney General to join or take legal action to protect such resources from premature retirement.

1.4.6 Rhode Island

In 2025, the legislature passed amendments to the state's 2014 Affordable Clean Energy Security Act allowing for the long-term procurement of nuclear power. The original Act established a coordinated process for the RI Public Utilities Commission, Division of Public Utilities and Carriers, and the Office of Energy Resources to work with electric and gas distribution companies — as well as other New England states — on potential investments in eligible hydropower, regional renewable energy resources, and infrastructure upgrades to support reliable transmission from these resources. The new law expands this process to include nuclear power.

In 2024, the Energy Storage Systems Act established deployment goals for energy storage capacity and directed the RI PUC to develop energy storage system tariffs. The Act recommends deployment goals for energy storage capacity of 90 MW by December 31, 2026; 195 MW by December 31, 2028; and 600 MW by December 31, 2033.

To meet these goals, the Rhode Island Infrastructure Bank is required to develop funding programs for both residential and commercial customers and for projects connected to the distribution or transmission system (i.e., in front-of-the-meter and not associated with a customer's electric load) and co-located with certain distributed energy resources.

The Act required the PUC to 1) adopt a framework for an energy storage system tariff to incentivize distribution-level projects and 2) adopt a framework for an interconnection tariff for projects connected to the distribution system that recognizes their flexible operating characteristics. Framework development is ongoing.

Additionally, the Act requires the PUC to conduct market surveys of storage capabilities every three years to assess whether they offer value to the distribution or bulk power systems. If capabilities are found to provide value, the PUC will initiate competitive solicitations for projects connected to the transmission or distribution system in front of the meter, including, but not limited to, long-duration energy storage projects. Long-duration energy storage projects are defined as systems capable of permanently displacing fossil fuels and balancing intermittent renewable energy resources.

In 2023, the legislature passed a bill identifying preferred sites for renewable energy development. Aiming to protect forested land, the bill revised the state's net metering program to prohibit projects in core forests. In 2024, the state enacted a law to incentivize responsible siting and development of renewable energy on previously contaminated properties.

1.4.7 Vermont

In June 2024, the Vermont House and Senate overrode Governor Phil Scott's veto of a bill to revise the state's Renewable Energy Standard (RES). The RES is Vermont's version of Renewable Portfolio Standards described in Section 1.4.1.

The previous RES (enacted in 2015) required utilities to buy 75% of their energy from renewable sources by 2032. The amended law accelerates that transition, requiring most retail electricity providers' annual load to be served entirely by renewable energy by 2030. The state extends the deadline until 2035 for municipal utilities and GlobalFoundries, the Essex Junction semiconductor manufacturer approved by the Vermont PUC in 2022 to establish its own electric utility. The amended law also requires utilities to purchase roughly 20% of their energy from in-state renewable sources over time (up from 10% in the previous law) and an additional 20% from new renewable sources in the region that can send power directly into the New England grid.

In 2023, the legislature enacted the Affordable Heat Act (Act 18), which required entities that import heating fuels into Vermont to reduce their GHG emissions each year as determined by the PUC, either through emission reductions or the purchase of "clean heat credits." The legislature directed the PUC to produce a final rule for the program in 2025. In January, the Commission delivered the Proposed Clean Heat Standard Rule and Second Checkback Report. After nearly 18 months of work on the Clean Heat Standard, the PUC concluded the program is not well-suited to Vermont. The PUC's report recommended alternative structures for consideration by the legislature, including a fuel tax, a thermal efficiency benefit charge, and a biofuels blending requirement.

In May 2025, Governor Scott issued Executive Order 04-25, directing the Agency of Natural Resources to pause enforcement of a multi-state plan requiring vehicle manufacturers to meet certain electric vehicle (EV) sales targets for passenger cars and medium- and heavy-trucks. Scott's order maintained his support for incentivizing Vermonters to transition to cleaner energy options like electric vehicles, but cited a lack of federal incentives, insufficient charging infrastructure and technological advances as barriers to meeting current goals.

1.5 Current Regional and State Greenhouse Gas Regulations and Goals

Limiting and eventually removing CO_2 and other greenhouse gases (GHGs) from the regional power sector has been a goal of many New England policymakers for more than a decade. Since RSP23, some RPS, clean energy standards, and GHG emission limits have increased. Current economy-wide goals, limits, and standards for all six states are shown in Table 1-1.

Table 1-1: New England State Goals for Reducing GHG Emissions

State	2020 Interim Target/Goal	Interim Target/Goal	2050 Target/Goal
Connecticut[5]	10% below 1990 levels	2040: 65% below 2021 levels 2030: 45% below 2001 levels	2050: net zero and 80% below 2001 levels
Maine[6]	10% below 1990 levels[7]	2045: Carbon neutral 2030: 45% below 1990 levels	2050: 80% below 1990 levels

[5] Conn. Gen. Stat. Sec. 22a-200a

[6] 38MRS§576-A

[7] In 2003, Maine enacted 38 MRSA §576, which set the 2020 interim target. In 2019, Maine repealed 38 MRSA §577 and replaced it with 38 MRSA §576-A, which established the 2030, 2045, and 2050 targets.

Massachusetts[8]	25% below 1990 levels	2040: 75% below 1990 levels 2030: 50% below 1990 levels 2025: 33% below 1990s level[9]	2050: net-zero and at least 85% below 1990 levels
New Hampshire	N/A	N/A	N/A
Rhode Island[10]	10% below 1990 levels	2040: 80% below 1990 levels 2030: 45% below 1990 levels	2050: Net zero
Vermont[11]	N/A	2030: 40% below 1990 levels 2025: 26% below 2005 levels	2050: 80% below 1990 levels
Carbon neutral and net zero refer to achieving net zero CO_2 emissions by balancing GHG emissions with sequestration and carbon offsetting, or through the elimination of CO_2 emissions entirely. For state-specific definitions, refer to the relevant state statutes.			

Five New England states have adopted GHG-reduction targets that establish either economy-wide or sector-specific limits on the distribution or sale of GHG-emitting products, including electricity.[12] All five states reported meeting their 2020 interim emission reduction goals and continue to work toward future targets.

1.5.1 Maine

In their Tenth Biennial Report on Progress toward Greenhouse Gas Reduction Goals, the Maine Department of Environmental Protection (DEP) reported that the state has surpassed its original interim target of 10% reduction in gross GHG emissions below 1990 levels — Maine achieved a 31% reduction by 2020, and a 30% reduction by 2021. As of 2021, the state has also achieved 91% carbon neutrality, meaning 91% of gross GHG emissions are balanced by sequestration in the environment.[13] In November 2024, the Maine Climate Council published an updated four-year climate-action plan, *Maine Won't Wait*, which outlines strategies to address and prepare for the impacts of climate change, and reduce GHG emissions.

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[8] *"An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy",* State of Massachusetts, accessed June 7, 2023.

[9] *"Massachusetts Clean Energy and Climate Plan for 2025 and 2030"*, State of Massachusetts, accessed March 13, 2023.

[10] R.I. Gen. Laws § 42-6.2-9

[11] *"Vermont Global Warming Solutions Act of 2020"*, State of Vermont, accessed June 7, 2023.

[12] *"Greenhouse Gas Emissions Reduction Targets and Market-based Policies"* National Conference of State Legislatures, last modified March 11, 2021.

[13] "Tenth Biennial Report on Progress toward Greenhouse Gas Reduction Goals," State of Maine, June 2024.

1.5.2 Massachusetts

Massachusetts satisfied its 2020 interim limit of 25% below 1990 levels, reporting a 31.4% reduction by 2020, and a 28% reduction by 2021.[14,15] The Clean Energy and Climate Plan (CECP) for 2025 and 2030 provides a roadmap for Massachusetts to achieve its upcoming interim emission reductions.

1.5.3 Rhode Island

In 2021, Rhode Island's legislature passed the *2021 Act on Climate*, which updated the GHG emission reduction goals from the *2014 Resilient Rhode Island Act* to a new goal of net zero emissions by 2050. By 2020, the state had met its interim target of 10% reduction in GHG emissions below 1990 levels, reporting emissions reductions of 20.1%.[16] The *2022 Rhode Island Greenhouse Gas Emissions Inventory* reported that from 1990 to 2022, the state achieved an 18.3% reduction in statewide net GHG emissions.

1.5.4 Connecticut

The *1990–2021 Connecticut Greenhouse Gas Emissions Inventory* released in April 2024 and updated in October 2024 included preliminary emissions reductions results for 2022. The state reported meeting its 2020 interim target of 10% reduction in GHG emissions below 1990 levels, reporting a 13.9% decrease by 2020. In 2022, the state reported a 28% reduction from 2001 levels.

1.5.5 Vermont

Vermont's Global Warming Solutions Act (GWSA) required the state to meet several annual GHG emissions targets. The first target was a 26% reduction in GHG emissions below 2005 levels by January 1, 2025. Vermont's most recent Greenhouse Gas Emissions Inventory and Forecast, published by the Agency of Natural Resources (ANR) in 2024, reported that 2021 statewide annual GHG emissions were 16% below 2005 levels, representing ~60% of the reduction necessary to meet the 2025 GWSA target. The second target of the GWSA is a 40% reduction in GHG emissions below 1990 levels by January 1, 2030. Through 2021, Vermont's annual GHG emissions fell 3% below 1990 levels, representing 8% of the reduction necessary to meet the 2030 GWSA target.

1.5.6 Tracking Regional Goals

The New England states continue to assess, develop, and implement other requirements, initiatives, and incentives to reduce GHGs. In aggregate, these GHG-reduction initiatives affect both individual combustion electric generators and the regional transmission system. The ISO continues to evaluate the impact of the states' various initiatives to reduce CO_2 and other emissions, including updates to the Regional Greenhouse Gas Initiative (RGGI), individual state limits on CO_2 emissions from power generators, changes to RPS targets, related new clean energy generation standards, and ongoing efforts to electrify the transportation and heating sectors.[17]

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[14] "Massachusetts Clean Energy and Climate Metrics," Commonwealth of Massachusetts, accessed May 2025.

[15] *"Statement of Compliance with 2020 Greenhouse Gas Emissions Limit,"* Commonwealth of Massachusetts, accessed March 13, 2023.

[16] "2020 Rhode Island Greenhouse Gas Emissions Inventory," State of Rhode Island, accessed May 2025.

[17] All New England states participate in RGGI, along with New York, New Jersey, Delaware, Maryland and Pennsylvania.

These existing and emerging efforts form part of the presentations and reports presented regularly to the ISO's Environmental Advisory Group, which is open to any interested stakeholders. Changes to RGGI requirements can have impacts on resource production and pricing. For example, a reduction in the emissions cap that is represented in RGGI can result in reduced production from emitting resources and/or a corresponding increase in power pricing.

1.6 Regional Emissions Trends

The ISO tracks the system emissions, rates, and trends for CO_2, NO_X (nitrous oxide), and SO_2 (sulfur dioxide) to help gauge the potential effects of future environmental regulations on the system and in response to requests from the states for emissions data. The ISO's annual air emissions report provides detailed historical trends and emissions rate data using methodologies developed with input from stakeholders. Figure 1-1 shows the annual emissions from generation within the region and imports from 2015 to 2024.

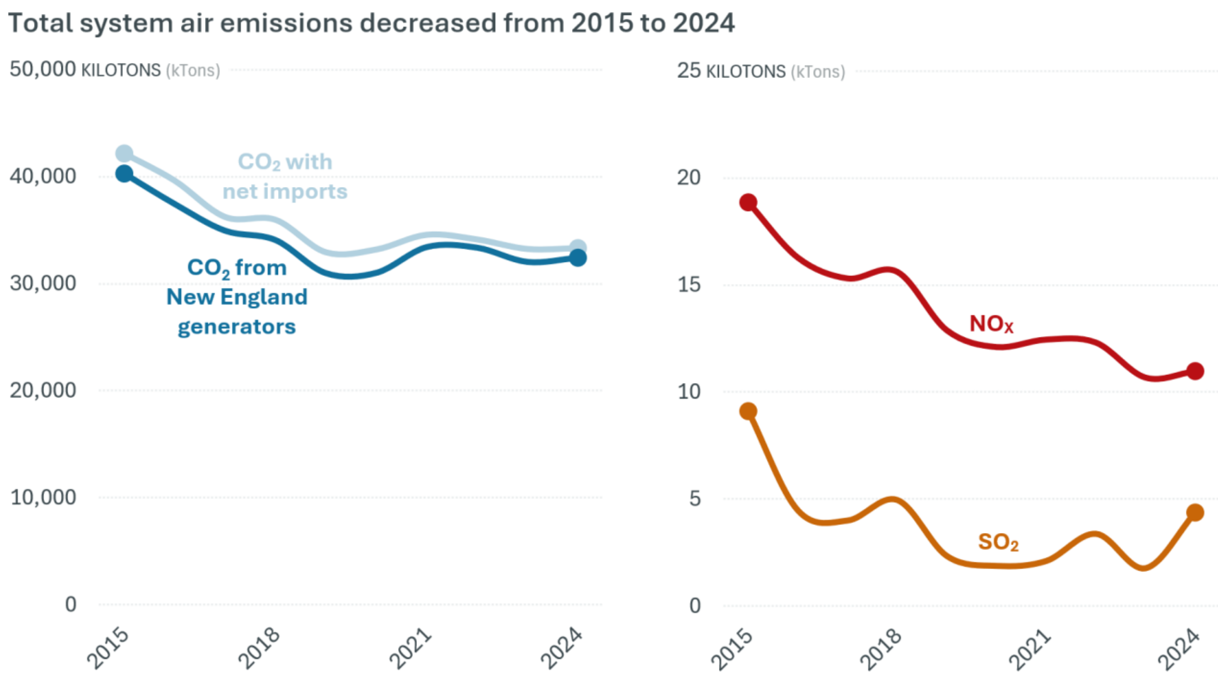

Figure 1-1: New England System Average Annual Emissions of NO_X, SO_2, and CO_2, 2015–2024 (kTons)[18]

Regional air emissions from power generators are sensitive to changes in weather, economic activity, energy prices, and the fuel mix. Over the past decade, a shift in generation production,

[18] Source: ISO-NE Air Emissions Reports. These annual reports provide a comprehensive analysis of New England electric generator air emissions (NO_X, SO_2, and CO_2) and a review of relevant system conditions, focused on direct emissions emitted by all solid, gaseous, and liquid fuel combusting generators in New England and includes emissions associated with net imports to serve load in New England.

lower demand, the implementation of increasingly stringent air-quality rules within and upwind of New England, and new incentives for lower-emitting resources have all contributed to declines in New England power sector emissions. From 2014 through 2023, total system emissions decreased (NO_X by 48%, SO_2 by 85%, and CO_2 by 18%). The current emissions trends result from the regional shift away from older oil- and coal-fired generation toward more efficient natural-gas-fired and non-emitting generation within New England.

Section 2
Forecasts of New England's Peak Demand and Annual Use of Electric Energy

The ISO's projections of changes in New England's electricity consumption over a 10-year forecast horizon provide foundational assumptions for ISO markets and studies. The state and federal policies discussed in Section 1 have significant impacts on regional electric energy consumption, and state policies in particular will further stimulate distribution-connected PV and drive increased electrification of the transportation and heating sectors. Over the next decade, electrification will drive an increase in demand, which is expected to more than offset the effects of distribution-connected PV reducing demand from the regional grid. The ISO's methodological improvements and innovation enable forecasts to keep pace with these emerging trends.

This section details the ISO's forecasts of gross and net annual energy and seasonal peak demand for 2025 through winter 2034-2035 that appear in the 2025-2034 CELT Report. Gross forecasts are before reductions from BTM PV, while net forecasts are after reductions from BTM PV. Net forecast corresponds to observed load and is used as an input in most planning studies.

Also included in this section are forecasts of the components of load, including transportation electrification, heating electrification, and distribution-connected PV, which also appear in the CELT Report. These forecasts provide key inputs for assessing the region's resource adequacy for future years (Section 5) and planning needed transmission improvements (Section 3). Both gross and net forecasts account for the impacts of electrification.[19]

The ISO made significant advancements in its methodology for the latest forecast, including:

- Modeling and forecasting base load net of energy efficiency (EE) directly, avoiding the need for a separate EE forecast
- Hourly modeling and simulation of all forecast components to better account for load components with different load shapes, which have varying operational needs
- Extending the forecast horizon to 20 years[20]

[19] Additional details of the forecast are located on the ISO's Load Forecast webpage. A high-level summary of current methodology and modeling is contained in Load Forecast Committee presentations Introduction to the CELT 2025 Load Forecast Cycle and Forecast Modeling (both September 27, 2024). All final forecast values are published in the 2025 Forecast Data spreadsheet. The Load Forecast Committee webpage contains materials on relevant stakeholder discussions.

[20] The CELT Report still includes 10-year forecasts, but the 2025 Forecast Data spreadsheet includes the new, longer horizon.

- Incorporating expanded weather data, including more weather variables from more locations throughout New England, and climate-adjusted data that reflects warming over time

2.1 ISO New England Gross Forecasts

The ISO develops its forecasts for gross annual electric energy use and seasonal peak demand using data on historical loads, trend variables that represent energy efficiency and macroeconomic factors, and anticipated electrification trends. The current forecasts of gross annual energy use, and both summer and winter gross seasonal peak demand, increase over the 2025–2034 forecast horizon, with much of the growth attributable to anticipated increases in electrification. Figure 2-1 shows the forecast for all three values over the forecast horizon.

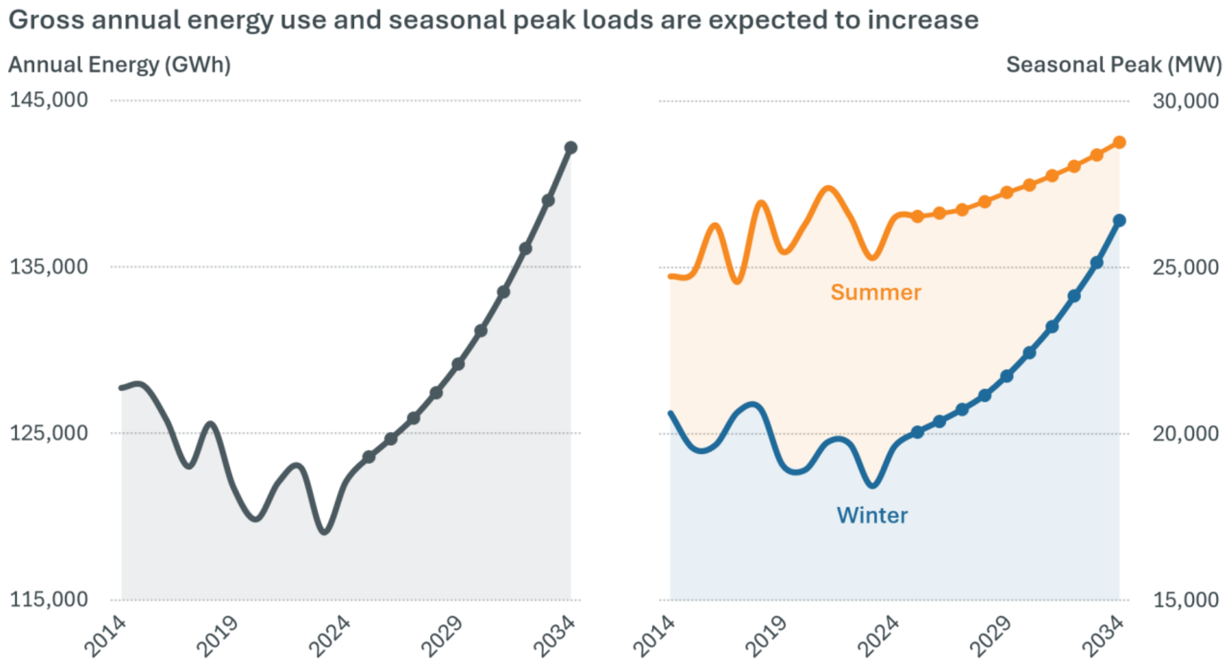

Figure 2-1: Forecast of Annual Gross Energy, Summer Gross 50/50 Peak Demand, and Winter Gross 50/50 Peak Demand

2.2 Electrification Forecasts

Strategic, policy-driven initiatives targeting economy-wide reductions in greenhouse gases continue to take shape across New England. Both the 2025 gross and net forecasts include the energy and demand impacts of heating and transportation electrification initiatives, which encourage consumers to adopt emerging technologies (e.g., electric vehicles (EVs) and electric heat pumps) that do not use conventional primary fuel sources. Electrification growth over the 2025–2034 forecast horizon will add considerable new demand for electricity across the region. Key inputs and feedback provided by representatives from each of the New England states, including state policymakers and regulators, helped guide the development of the 2025–2034 heating and transportation electrification forecasts. A full explanation of the methodology used for both are available in the [2025 Heating Electrification Forecast] and [2025 Transportation Electrification Forecast].

2.2.1 Heating Electrification Adoption

The heating electrification forecast projects the incremental energy and peak demand impacts (relative to the base year 2024) of residential and commercial heat pump adoption for space and water heating over the next 10 years. Relative to the 2024 forecast, heat pump adoption projections have been reduced by approximately 12% regionwide to reflect recent trends in program and policy data in Massachusetts and Connecticut. The current forecast projects the region will rely on electricity to heat almost 1.1 million households and over 800 million square feet of commercial space across New England over the following decade, beyond what is currently installed. Heating electrification will increase electricity consumption mostly from October through April.

Figure 2-2 shows the outlook for cumulative regional adoption (on a percent basis) of electrified heat for residential and commercial buildings, based on total number of households and total square feet, respectively. The future electrified shares plotted are based on the total building stock using legacy fossil fuel heating sources at the end of 2024. The dark blue portion of the plots represents the relative share of buildings for which heat pumps will supply all of the heat (i.e., "full" heating). The light blue portion of the plots represents heat pump installations that supply most of the heat (i.e., "partial" heating), but are supplemented by a non-electric backup heating source that provides all of the heat below certain temperatures, centered around 20ºF.

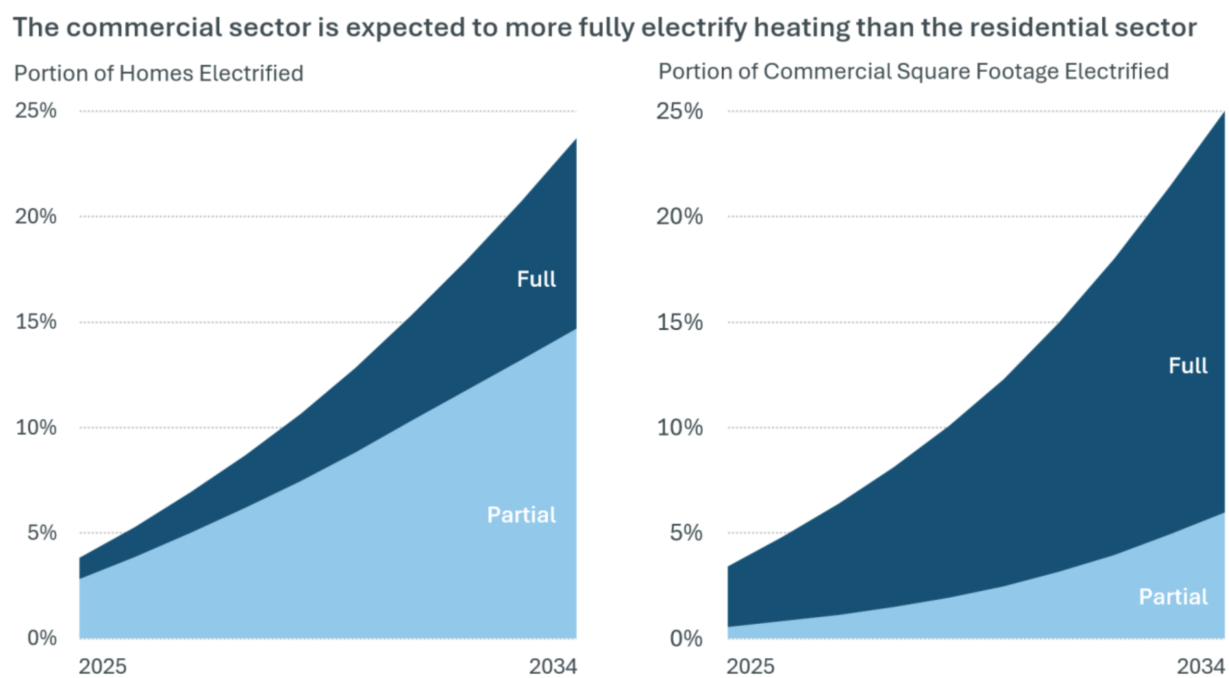

Figure 2-2: Projection of Heating Electrification in Residential and Commercial Building Stock, 2025–2034

2.2.2 Transportation Electrification Adoption

The transportation electrification forecast projects the incremental energy and demand impacts (relative to the base year 2024) of adoption of EVs over the next 10 years. EV adoption projections were revised downward relative to prior forecasts to better align with recent historical EV adoption rates in each state.

Figure 2-3 illustrates the outlook for cumulative regional adoption (as a percentage of total vehicle stock) of electrified light-duty personal vehicles, light-duty fleet vehicles, medium-duty delivery vehicles, school buses, and transit buses. The adoption forecast projects the electrification of nearly 2 million vehicles, or approximately 18% of all vehicle stock across New England, by 2034. Electric vehicle stock in 2024 was approximately 2%.[21]

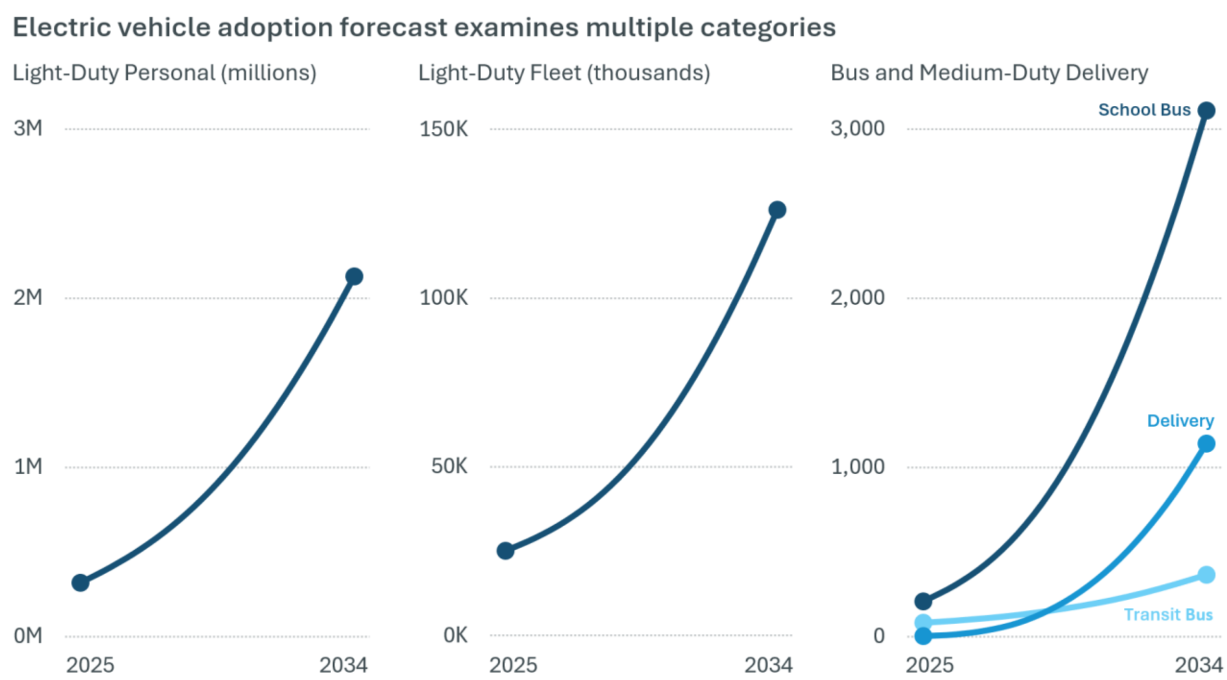

Figure 2-3: Projection of Share of Electrified Transportation Across Various Vehicle Classes, 2025–2034

2.2.3 Electrification Impacts on Electric Energy and Demand

Figure 2-4 illustrates the regional impacts of both heating and transportation electrification over the next 10 years. By 2034, the regional impacts of electrification will add 16,782 gigawatt-hours (GWh) of overall annual electricity use in New England as compared to 2024 levels, 956 megawatts (MW) of peak demand under typical summer peak weather conditions (known as the summer "50/50" demand), and 6,529 MW of winter peak demand under typical winter peak weather conditions (known as the winter "50/50" demand).

[21] Cited historical EV penetration values are estimates based on vendor-provided and publicly available data.

Electrification accounts for most of the growth in the energy and demand forecasts. Electrification is responsible for 12.8% of net energy in the 2034 annual electricity use forecast, 3.6% of net demand for the 2034 summer 50/50 demand forecast, and 25.1% of net demand for the 2034 winter 50/50 demand forecast.

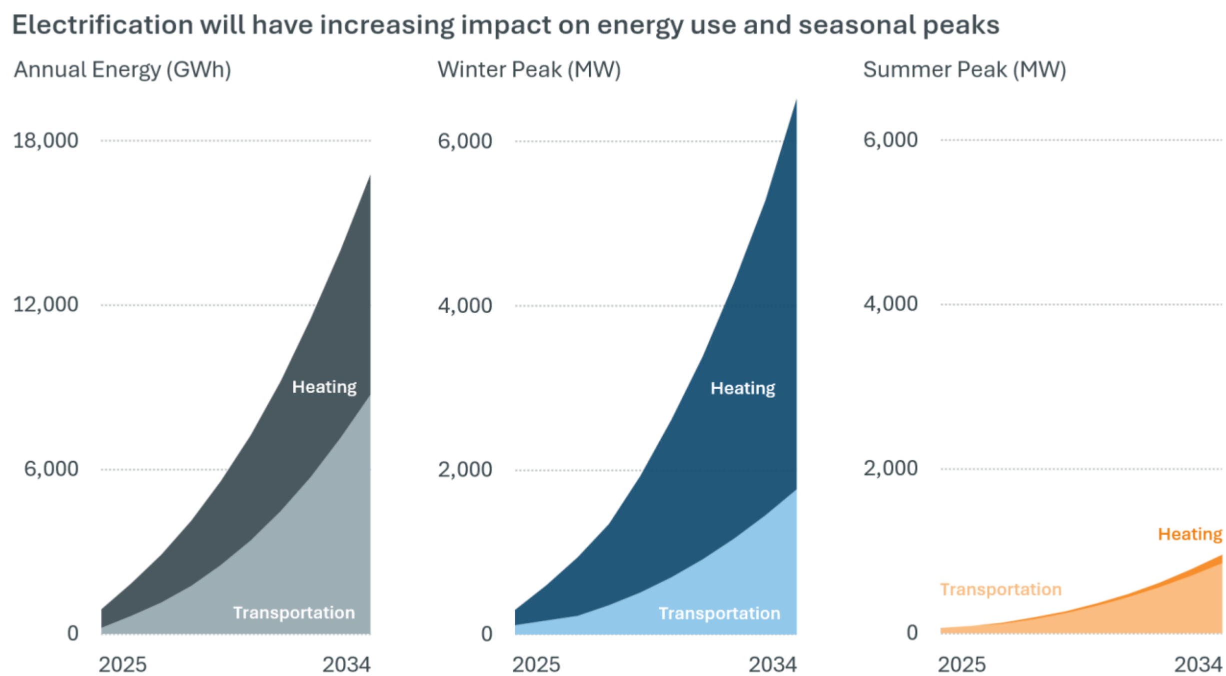

Figure 2-4: Total Electrification Impacts to Regional Annual Energy and Seasonal 50/50 Peak Demand, 2025–2034

2.3 Distributed Photovoltaic Generation Forecast

Distributed PV has grown substantially in New England since 2012, and it has already significantly altered the region's seasonal load profiles.[22] The 2025–2034 forecast shows the nameplate capacity of distributed PV resources more than doubling over the next decade. As production from these PV resources increases, so will the need for resource ramping to serve the increasing fluctuations in net demand. Such fluctuations drive an increase in light-load conditions, especially during the shoulder seasons, since much of this PV is embedded in load.[23] A full explanation of the methodology used for this forecast is available in the 2025 PV Forecast.

As part of PV forecasting, the ISO first develops state-by-state forecasts of the growth in PV nameplate capacities (MW_{ac} [megawatts of alternating current] ratings) through the 10-year

[22] The ISO continues to monitor the growth of *non*-PV distributed generation, including BTM energy storage facilities, to determine whether separate forecasts of these resources may eventually be warranted.

[23] Ramping up and ramping down refer to generators' increasing or decreasing output to meet changing load levels, such as in the early morning, which typically involves ramping up, and in the late evening, which typically involves ramping down.

planning horizon.[24] To ensure proper accounting, the ISO classifies PV into three types, each of which is treated differently in system planning studies:

- PV resources with capacity supply obligations in the Forward Capacity Market (FCM)
- Energy-only resources (EORs), which are generation resources that participate in the wholesale energy markets but choose not to participate in the FCM[25]
- BTM PV, which does not participate in wholesale markets and reduces the load the ISO observes

Figure 2-5 shows how FCM, EOR, and BTM PV contribute to the total PV nameplate capacity forecast for 2025–2034.

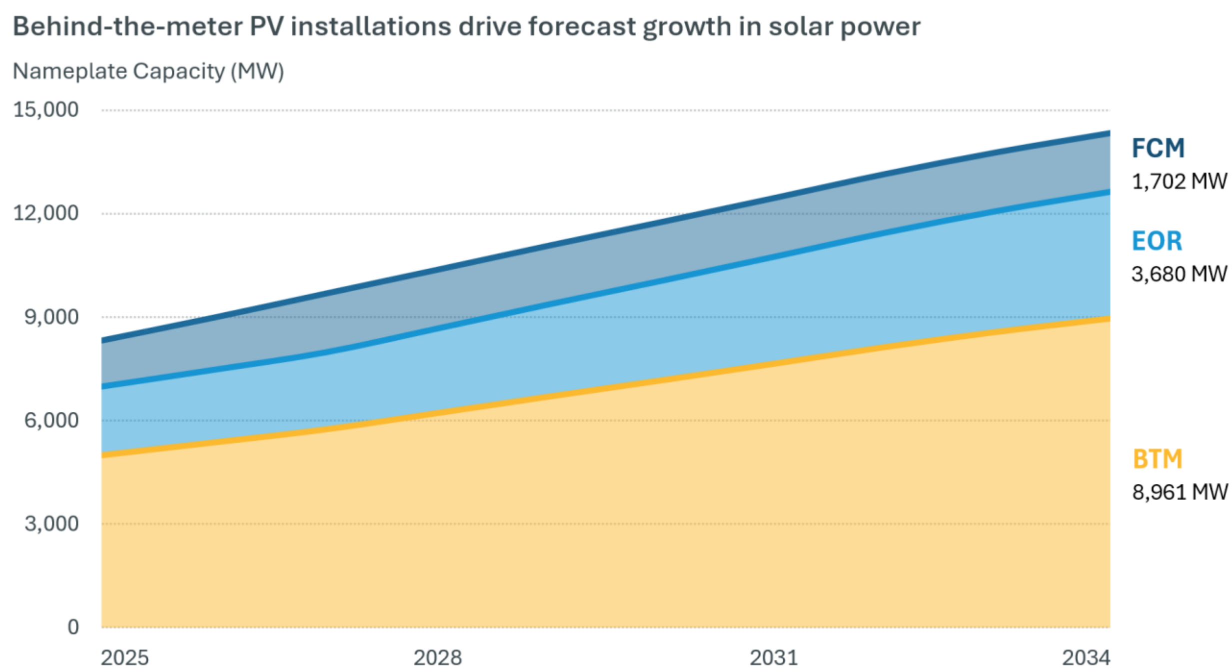

Figure 2-5: Classification of 2025-2034 Cumulative PV Nameplate Capacity Forecast

2.3.1 Forecasts of Behind-the-Meter Photovoltaic Energy and Summer Peak Demand Reductions

Using the nameplate BTM PV forecast and other available data, the ISO develops forecasts of BTM PV energy and corresponding reductions in summer peak demand. Higher PV penetrations are associated with diminishing incremental peak demand reductions. Future PV growth will be less

[24] The forecast reflects distributed PV, which includes projects typically 5 MW or less in nameplate capacity. Therefore, the forecast does not incorporate policy drivers for larger-scale projects, which are generally accounted for as part of ISO's interconnection process and participate in wholesale markets.

[25] Settlement-only resources and non-FCM generators, as defined in Operating Procedure No. 14 (OP 14), Technical Requirements for Generators, Demand Response Resources, Asset Related Demands, and Alternative Technology Regulation Resources, are included in this market type.

useful in reducing forecast peaks in summer demand than it is today. As peaks in summer demand continue to occur later in the day, estimated reductions in summer peak demand due to BTM PV grow only marginally, from a 1,736 MW reduction in 2025 to a reduction of 1,879 MW in 2034. Also, as heating electrification increases in the future, winter peaks will begin to occur during morning daylight hours, enabling BTM PV to slightly reduce winter peak loads. Figure 2-6 shows the values of regional annual energy savings and 50/50 seasonal peak demand reductions from the 2025 forecast of BTM PV.

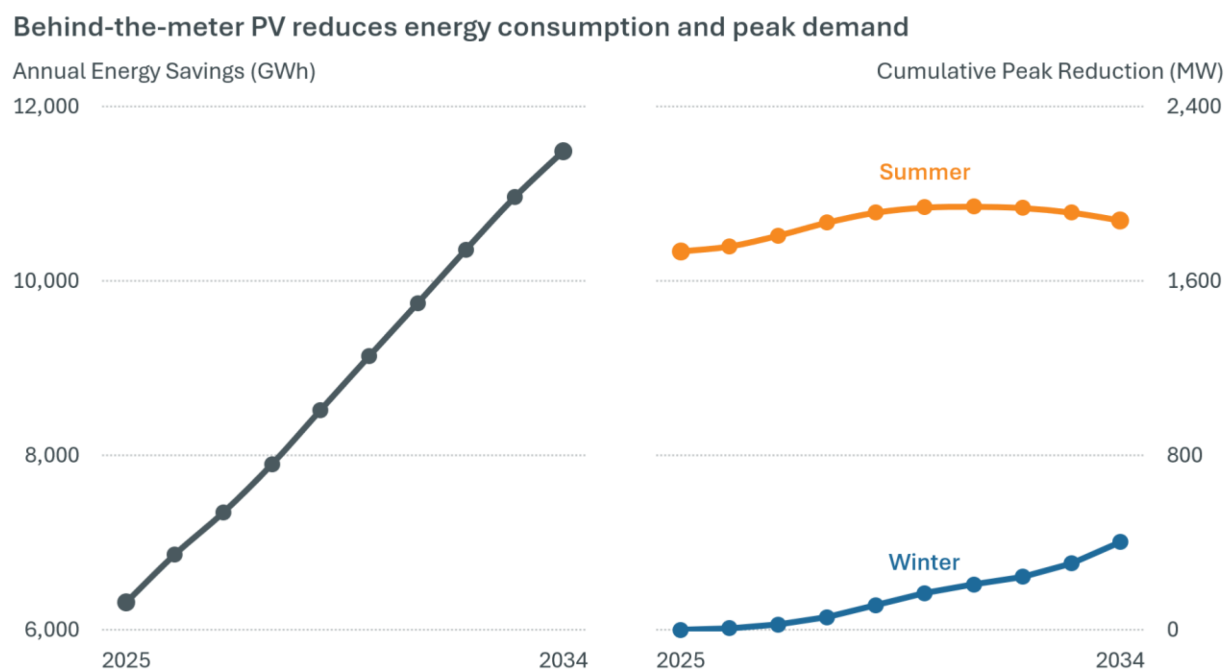

Figure 2-6: Forecast of BTM PV Annual Energy and Estimated Summer Peak Demand Reductions, 2025-2034

2.4 Net Demand Forecast

The ISO's net demand forecast is the gross demand forecast, including the impacts of electrification, less the BTM PV forecast. Figure 2-7 shows the net demand forecasts for annual energy, summer 50/50 peak demand, and winter 50/50 peak demand. All net forecasts show growth over the forecast horizon, largely due to increasing electrification.

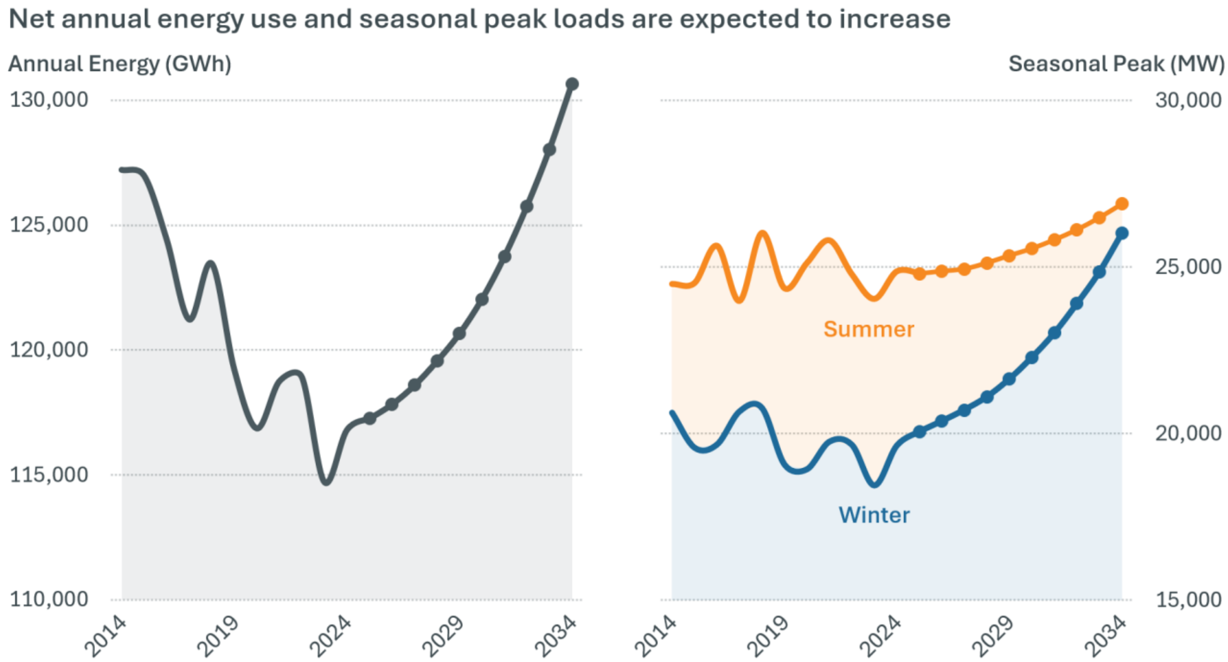

Figure 2-7: Forecast of Annual Net Energy, Summer Net 50/50 Peak Demand, and Winter Net 50/50 Peak Demand

The net systemwide load factor is the ratio of the average hourly load for a year to peak hourly load, based on the net 50/50 demand and annual energy forecasts, and is intended to express the efficiency of energy use. This load factor increases slightly over the forecast horizon, from 54.0% to 55.5%. While the forecast indicates that summer will remain the typical peak season over the forecast horizon, the anticipated impacts of electrification will drive a slight increase in load factor, meaning that growth in overall energy consumption will begin to slightly outpace growth in the annual peak.

Figure 2-8 shows the winter (in blue) and summer (in orange) peak demand forecast distributions over the 10-year planning horizon, illustrating the degree to which the forecasted increases in electrification will drive a convergence in summer and winter peak demand magnitude. The 50/50 net summer peak forecast grows by 2,094 MW (~8.4%) from 2025 to 2034, while the 50/50 net winter peak forecast grows by 5,964 MW (~29.7%) over the same period, driven primarily by the expected increase in electrified heating. Over the forecast horizon, the difference in these forecasts shrinks from 4,747 MW in 2025 to 877 MW in 2033.

The 90/10 net summer peak forecast, which represents demand during a particularly hot summer heat wave, grows by 2,411 MW (~9.3%) between 2025 and 2034. However, the 90/10 net winter peak forecast, which represents demand during a particularly significant cold snap, grows by 7,589 MW (~35.9%) over the same period. Over the forecast horizon, the summer forecast is 4,761 MW higher in 2025; however, by 2034 the winter forecast is 417 MW higher.

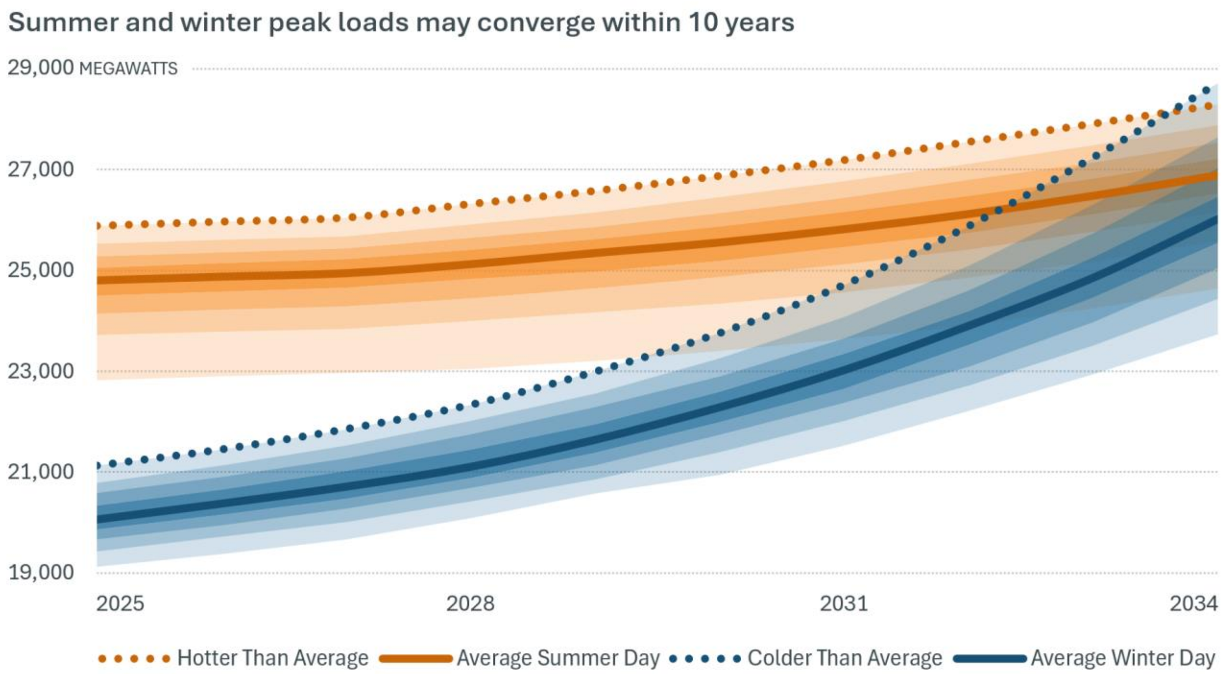

Figure 2-8: Forecast Summer and Winter Seasonal Net Peak Demand Distributions, 2025–2034

2.5 New Large Loads and Data Centers

The ISO is following the potential for development of new large loads, such as data centers, in the region. While New England has not experienced the surge in interest other areas of the US have seen, the ISO is working with Transmission Owners to develop as much visibility as possible and inform considerations regarding the treatment of these additional large sources of demand in the forecast going forward. Data center development can be very speculative and is very sensitive to technology industry investment cycles and these dynamics will have to be considered when factoring in these types of loads.

Section 3
Transmission System Performance, Upgrades and Needs Assessments

Since 2002, the ISO and regional stakeholders have made significant progress developing transmission solutions that address existing and projected system needs. Transmission infrastructure and related projects help maintain system reliability and enhance the region's ability to support a robust, competitive wholesale electricity market by moving power from where it is produced — whether that is within New England or an external region — to the region's load centers.

This section provides an overview of the New England transmission system, updates on its performance, the status of several key transmission planning studies, and the progress of major transmission projects and upgrades in the region as of June 2025.[26] Transmission planning studies account for known plans for resource additions and retirements (see Section 5) and the material effects of PV and electrification forecasts (see Section 2).

The ISO's planning role ensures that the power system continues to operate reliably as conditions on the grid change. In addition, the planning group oversees transmission driven by other needs, which can be identified and procured in different ways pursuant to Attachment K of the OATT:

- Reliability transmission upgrades ensure that system reliability criteria set by the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and the ISO are met.
- System efficiency transmission upgrades (formerly market efficiency transmission upgrades) are identified by the ISO to provide financial benefits to the system that exceed the cost of the transmission upgrade.
- Public policy transmission upgrades are improvements of or additions to the regional transmission system designed to meet state, federal, and local (e.g., municipal and county) public policy requirements identified as driving transmission needs.
- Longer-term transmission upgrades are developed using the Longer-Term Transmission Planning (LTTP) process by coordinating with NESCOE to identify high-level concepts of transmission infrastructure that could meet one or more state's energy policy, mandate, or

[26] For further details on transmission planning and individual transmission projects, see PAC presentations, and the RSP Project List and Asset Condition List.

legal requirement based on state-identified scenarios and timeframes, which may extend beyond the 10-year planning horizon.

Transmission upgrades are developed through competitive processes when needs assessments reveal a reliability non-time-sensitive need or when system efficiency, public policy, or longer-term transmission needs are identified. The ISO conducts an RFP process to identify competitive solutions to solve these needs.[27]

The *Transmission Planning Process Guide* details the existing regional system planning process and how transmission planning studies are performed, and the *Transmission Planning Technical Guide* details the standards, criteria and assumptions used in transmission planning studies.

3.1 Overview of New England's Transmission System

New England's power system provides electricity to diverse areas, ranging from rural agricultural communities to densely populated cities, and integrates widely dispersed and varied types of power supply resources. Geographically, about 77% of New England's peak loads are in the southern states of Massachusetts, Connecticut, and Rhode Island, while around 23% are in the northern states of Maine, New Hampshire, and Vermont.[28] Although northern states are geographically larger than the southern states, the larger population centers of southern New England have larger electricity needs, and require more transmission infrastructure. Power on the transmission system typically flows from west to east and from north to south. However, flows change throughout each day, and the predominant flows may change significantly with future installation of distributed energy resources and offshore wind.[29] Because the demands on the New England transmission system can vary widely, the system must at all times be able to reliably operate under the wide range of conditions — in compliance with mandatory reliability standards — to move power from where it is produced to the region's load centers.

The regional transmission system consists of mostly 115, 230, and 345 kilovolt (kV) transmission lines, which are generally longer and fewer in number in northern New England than in southern New England. The region has 13 interconnections with neighboring power systems in the United States and eastern Canada:

- **Nine** interconnections are with New York (NYISO) — two 345 kV ties; one 230 kV tie; one 138 kV tie; three 115 kV ties; one 69 kV tie; and one 330 MW, ±150 kV high-voltage direct-current (HVDC) tie), called the Cross-Sound Cable interconnection.
- New England and the Canadian Maritimes (New Brunswick Power Corporation) are connected through **two** 345 kV alternating current (AC) ties.[30]
- New England also has **two** HVDC interconnections with Québec (Hydro-Québec or HQ). One is a 120 kV AC interconnection with a 225 MW back-to-back converter station

[27] Reliability time-sensitive needs are addressed through the solutions study process described in section 4.2 of Attachment K.

[28] Peak loads can vary from month to month, day to day and hour to hour. Values cited are seasonal approximations.

[29] See historical flow estimates of the hourly flows and limits on New England's thermal interfaces for additional detail.

[30] Aroostook County and part of Washington County in Maine receive electricity service from New Brunswick, Canada.

(Highgate in northern Vermont), which converts AC to DC and then back to AC. The second is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (Phase II). An additional ±320 kV HVDC line allowing up to 1,200 MW to be delivered to Larrabee Road in Maine is scheduled to enter service by the end of 2025.

3.2 Evolving Transmission Planning Issues

Increasing electrification and a shifting resource mix present new challenges for the New England transmission system and continue to influence the ISO's approach to transmission planning. This section describes some of these evolving approaches.

3.2.1 Longer-Term Transmission Planning

In the *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid*, NESCOE identified a need for changes in transmission system planning, and recommended that the ISO identify process changes to allow for a routine transmission planning process to help "inform all stakeholders of the amount and type of transmission infrastructure needed to cost-effectively integrate clean energy resources."

In response, the ISO revised Attachment K to incorporate a new transmission planning process designed to look beyond the current 10-year planning horizon. The first phase of the effort established rules to allow New England states to request that the ISO routinely perform scenario-based transmission planning studies. The ISO filed the Attachment K longer-term transmission study changes with FERC on December 27, 2021, and FERC accepted the changes on February 25, 2022. The *2050 Transmission Study* detailed in Section 1.3.1 is the first example of this kind of study.

On July 8, 2024, FERC accepted the second phase of the ISO's LTTP tariff changes (see Section 1.3.1). The changes create a new process allowing the region to implement transmission system upgrades based on the results of longer-term transmission studies. The process, which operates in addition to current transmission planning protocols, provides an avenue for the states to evaluate and finance transmission upgrades needed to ensure a reliable grid throughout the clean energy transition. At the request of NESCOE, the ISO will issue RFPs to address selected needs. In addition, the ISO will provide technical assistance in support of their procurements and efforts to secure federal funding for transmission investments.

Evaluation metrics include cost-saving regional benefits, project costs, urgency of need, environmental impact, siting, and other factors. Since larger transmission projects can help transfer power from larger renewable resources in rural areas to more densely populated areas, these projects may offset the need for new generating resources in urban and suburban locations. Methods to measure such benefits are included in the evaluation process.

On December 13, 2024, NESCOE requested the ISO issue an RFP under the new process to address the following needs by 2035:

- Increase Surowiec-South interface limit to at least 3,200 MW
- Increase Maine-New Hampshire interface limit to at least 3,000 MW
- Accommodate the interconnection of at least 1,200 MW of new onshore wind at or near Pittsfield, Maine

The ISO issued the RFP on March 31, 2025. The deadline for Qualified Transmission Project Sponsors (QTPSs) to submit proposals is September 30, 2025. The ISO anticipates making recommendations by September 2026.

3.2.2 Storage as Transmission-Only Assets

In response to stakeholder requests, the ISO has developed a process to allow for storage facilities to be considered transmission-only assets (SATOAs).[31] This would allow storage to be considered in both the solutions study process and the competitive solution process, subject to certain limitations. In developing the proposal, two overarching principles emerged: 1) the introduction of a SATOA cannot compromise reliability by introducing unmanageable operating burdens into the control room, and 2) it cannot have a significant impact on the markets. The ISO filed tariff revisions with FERC on December 29, 2022 (Part 1 and Part 2), and FERC accepted those changes on October 19, 2023. On February 7, 2025, the ISO, joined by the NEPOOL Participants Committee, submitted tariff revisions to establish Metered Quantity for Settlement rules for SATOAs and provided notice that the effective date for SATOAs is September 1, 2026. FERC accepted the ISO's submittal and effective date on April 8, 2025.

3.2.3 New BPS Testing

On March 27, 2020, NPCC revised Regional Reliability Reference Criteria A-10, *Classification of Bulk Power System Elements* (A-10), which changed the assumptions used to conduct bulk power system (BPS) testing. Before these revisions, study cases assumed that major interfaces were stressed to their limits. These assumptions were revised to represent at least the 98th percentile of historical flows, adjusted for known future system changes. In October 2022, the ISO shared with the PAC the results of the most recent BPS classification study, and based on results, removed 19 existing buses from the NPCC BPS List.

The changes to A-10 also separated transfer limits from BPS testing. Transfer limit updates that resulted from changes were presented at the June 2024, December 2024, and April 2025 PAC meetings. The new transfer limits represent system conditions before and after the New England Clean Energy Connect (NECEC) project and its associated upgrades are placed in service, and system conditions with NECEC both online and offline. These new limits are as follows:

Table 3-1:
Updated Transfer Limits with and without the New England Clean Energy Connect project

Interface Name	Previous Transfer Limit	June 2024 PAC New Transfer Limit (Pre-NECEC)	December 2024 PAC New Transfer Limit (Post-NECEC) and NECEC online	April 2025 PAC New Transfer Limit (Post-NECEC) and NECEC offline
Orrington – South	1,325 MW	1,650 MW	1,650 MW	1,650 MW
Surowiec – South	1,500 MW	1,800 MW	2,800 MW	2,200 MW

[31] A SATOA is an energy storage device connected to the PTF at 115 kV or higher which can inject stored power to address specific transmission system concerns.

Interface Name	Previous Transfer Limit	June 2024 PAC New Transfer Limit (Pre-NECEC)	December 2024 PAC New Transfer Limit (Post-NECEC) and NECEC online	April 2025 PAC New Transfer Limit (Post-NECEC) and NECEC offline
Maine – New Hampshire	1,900 MW	2,000 MW	2,200 MW	2,200 MW

The impacts of updated Maine interface transfer limits to transfer capabilities used in capacity markets were presented to the PAC on April 29, 2025.

3.3 Completed Major Projects

Several recent projects have addressed potential post-contingency overloads and voltage concerns. Additionally, projects in the Boston area have mitigated potential short circuit levels. The following is a list of major projects that have been completed or are near completion since RSP23:

- Greater Boston 345 kV upgrades, where projects included installing new lines, an autotransformer, and reactive support to maintain voltage; 230 kV upgrades, which included installing an autotransformer; 115 kV upgrades, which included installing a new station, lines, and reactive support to maintain voltage; and several other upgrades. The suite of projects also included the addition of a ±200 megavolt-ampere reactive (MVAR) static synchronous compensator (STATCOM) in Maine.[32] All upgrades were in-service by June 2025.[33]
- New Hampshire 2029 Upgrades included the installation of two 50 MVAR capacitors called the Browns River station on Line 363 near Seabrook Station, the installation of a +127/−50 MVAR synchronous condenser at Amherst, a +55/−32.2 MVAR synchronous condenser at Huckins Hill, and a +55/−32.2 MVAR synchronous condenser at North Keene. All upgrades were in-service by June 2025.[34]
- Eastern Connecticut 2029 Upgrades included a 345/115 kV autotransformer and 115 kV upgrades that include the conversion of a line from 69 kV to 115 kV, the reconductoring of a line, and the installation of a synchronous condenser, a series reactor, a capacitor, and two series breakers. In addition, a station was upgraded to meet bulk power system standards. All upgrades were in-service by January 2025.[35]

Study efforts continue throughout New England to address the issues discussed in the next section.

[32] A STATCOM is another type of flexible alternating-current transmission system device.

[33] The total cost of the Greater Boston upgrades is $1,201M.

[34] The total cost of the New Hampshire 2029 Upgrades is $161M.

[35] The total cost of the Eastern Connecticut 2029 Upgrades is $260M.

3.4 Key Study Area Updates

Several key study areas, shown in Figure 3-1 and detailed below, reflect ongoing study efforts on a wide range of system concerns.

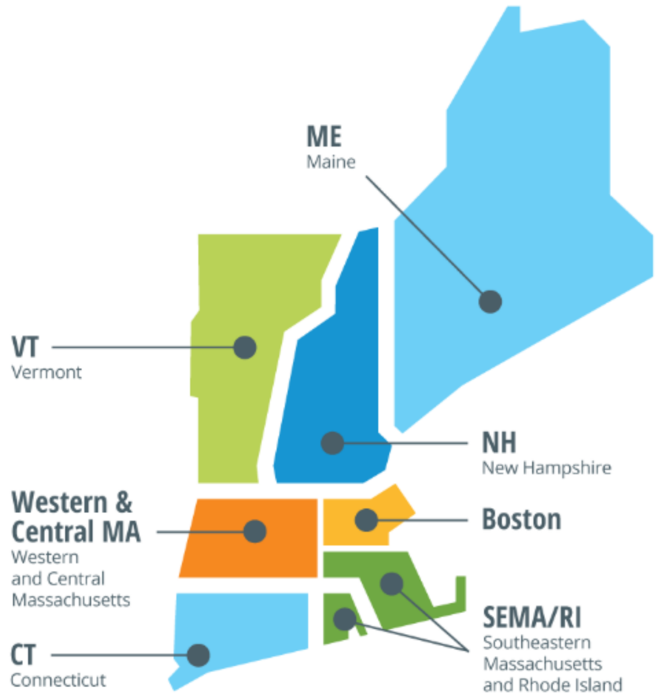

Figure 3-1: Key Study Areas in New England

New England Needs Assessments identify the ability of areas of the New England PTF to meet NERC, NPCC, and ISO New England planning criteria. These assessments are performed as changes in assumed system conditions warrant, rather than on a predetermined schedule. The ISO recently completed or is actively working on the following Needs Assessments:

- Boston 2033 Needs Assessment
- Vermont 2033 Needs Assessment
- 2028 New England Short Circuit Needs Assessment
- Connecticut 2034 Needs Assessment

3.4.1 Boston 2033 Needs Assessment

The *Boston 2033 Needs Assessment*, published in May 2024, included numerous time-sensitive and non-time-sensitive needs. The resulting *Boston 2033 Solutions Study*, designed to solve time-sensitive-needs, was completed in April 2025. The study identified required upgrades, including modification of the protection systems at three 345 kV stations (Stoughton, West Walpole, and

Holbrook) and two 115 kV stations (Hyde Park and K Street) and the installation of a 115 kV 80 MVAR shunt reactor at Electric Avenue.

3.4.2 Vermont 2033 Needs Assessment

An overview of the *Vermont 2033 Needs Assessment* results were presented to the PAC in December 2023. Only one non-time-sensitive need was observed due to a thermal violation — a thermal rating over the imposed limit — under 2032-2033 winter peak load conditions. Since the need-by date of the thermal violation was in the ninth year of the ten-year study horizon, and several evolving factors could impact that need or potential solutions, the ISO proposed a pause in the process and did not immediately start the competitive solution process. The final *Vermont 2033 Needs Assessment*, which concluded the study effort, was published in June 2024.

3.4.3 2028 New England Short Circuit Needs Assessment

The *2028 New England Short Circuit Needs Assessment* results were presented to the PAC in July 2023.[36] Circuit breakers were observed to be overdutied in the Maine, Western and Central Massachusetts (WCMA), and Southeastern Massachusetts and Rhode Island (SEMA/RI) Key Study Areas, and these needs were deemed time-sensitive.[37] The ISO completed Solutions Studies for WCMA and RI in December 2023, for SEMA in April 2024, and for Maine in June 2024.

3.4.4 Connecticut 2034 Needs Assessment

The Connecticut 2034 Needs Assessment Revision 1 results were presented to the PAC in July 2025, and included various time-sensitive and non-time-sensitive needs.[38] The subsequent Solutions Study to solve time-sensitive needs is ongoing, with completion expected by early 2026.

3.5 2050 Transmission Study

The 2050 Transmission Study identified possible transmission system deficiencies in serving load in 2035, 2040, and 2050, and developed high-level transmission upgrade concepts and associated cost estimates to address these deficiencies.

The inputs for the 2050 Transmission Study were based on the All Options Pathway in the *Massachusetts 2050 Decarbonization Roadmap*, and include the following assumptions: development of significant new offshore wind, solar, and battery resources; retirement of significant portions of the fossil-fueled generation fleet, including all oil and coal generators, by 2035; and large increases in electric load due to the electrification of transportation and heating.

[36] The 2028 New England Short Circuit Needs Assessment was later revised in October 2023, and an addendum to the 2028 New England Short Circuit Needs Assessment was published in March 2024.

[37] SEMA/RI is typically a single Key Study Area, but for the 2028 New England Short Circuit Needs Assessment, SEMA and RI were addressed separately.

[38] The draft Connecticut 2034 Needs Assessment report was posted in March 2025. After the stakeholder comment period closed, a Transmission Owner submitted new modeling information for the upcoming 2025 Transmission Planning Base Case Library build. The new modeling information had the potential to impact the needs observed in the Connecticut 2034 Needs Assessment, so a new revised Connecticut 2034 Assessment was initiated.

The 2050 Transmission Study examined summer peak loads of approximately 40 gigawatts (GW) by 2050, and winter peak loads of approximately 57 GW by 2050.

Final 2050 Transmission Study results were presented to the PAC in October 2023, and the final report was published in February 2024.[39] The study presented four "high-likelihood concerns" — transmission areas that have a high likelihood of thermal violation even if the assumptions explored in the study do not unfold exactly as predicted. These concerns satisfied the following criteria:

- It appeared in two or more load levels.
- It did not rely heavily on specific substation-level generator locations.
- It did not rely heavily on load growth at a particular substation.

The high likelihood concerns that satisfied these criteria were as follows:

- **North-South:** The Maine-New Hampshire and North-South transmission interfaces showed thermal overloads primarily during winter peak snapshots that were precipitated by the large volume of offshore wind production flowing from relatively generation-heavy and light-load areas in Maine and New Hampshire into the dense, high-load areas in southern New England.
- **Boston Import:** Across most snapshots studied, current import paths into the Boston area are unable to support increasing load due to high load density and low assumed availability of wind generation in the area under summer peak load conditions.
- **Northwest Vermont Import:** The overloads stemmed from the significant amount of forecasted load in the Burlington area without a corresponding amount of local generation, combined with the lack of significant 345 kV transmission lines transferring power into the area. These overloads were observed exclusively in the winter, when load is expected to be highest, as heating in the region becomes significantly more electrified.
- **Southwest Connecticut Import:** Thermal concerns appeared across all load levels studied due to the high load density and limited 345 kV paths into the area.

After completion of the initial study, the ISO conducted various additional analyses based on stakeholder feedback:

- Explored potential cost reductions of relocating offshore wind points of interconnection from the initial study from Maine to Massachusetts. Results were presented to the PAC in April 2024.
- Analyzed 50 coastal points of interconnection to assess viability for connecting offshore wind. Results were presented to the PAC in August 2024.[40]

[39] The Longer-Term Transmission Studies section of the ISO website provides all 2050 Transmission Study PAC meeting materials.

[40] Responses to stakeholder comments were posted in October 2024.

- Published the *2050 Transmission Study – Maximum Transmission Element Loading* results dataset in January 2025 to show a range of maximum loading observed on each element in the 2050 Transmission Study.
- Published the *2050 Transmission Study: Offshore Wind Analysis* results in March 2025, which summarized the reduction in costs from relocating offshore wind interconnection further south, and assessed the maximum output of offshore wind projects that could interconnect to New England without significant transmission upgrades.

In both the initial study and additional analyses, the 2050 Transmission Study effort informed stakeholders about the amount and type of transmission infrastructure needed to cost-effectively serve load over the next three decades in anticipation of increased electrification, accelerated development of renewable resources, and retirement of a significant portion of New England's fossil-fueled generation fleet.

3.6 Public Policy

FERC Order No. 1000 directs regions such as New England to establish a process to identify public policy requirements that drive a transmission need and, if necessary, to evaluate potential solutions. The ISO's 2023 process did not identify any federal or local public policy requirements that would drive a transmission need, and concluded no Order No. 1000 public policy transmission study was necessary that year.[41] In January 2026, the ISO will initiate the public policy process again to solicit input from stakeholders and the New England states about public policy requirements.

3.7 Local System Plan

The Local System Plan (LSP) process is described in the OATT, Attachment K, Appendix 1. In general, LSP projects are needed to maintain the reliability of the non-PTF system. While LSP projects are designed to serve the needs of the non-PTF system, they typically involve PTF components. These components are not eligible for cost regionalization since they are prompted by a non-PTF need. Information regarding LSP projects is provided to stakeholders through Transmission Owner Planning Advisory Committee (TOPAC) meetings.[42]

3.8 RSP Project List and Projected Transmission Project Costs

The RSP Project List is a summary of necessary regional transmission projects and includes information on project type, primary owner, transmission upgrades and their status, and estimated cost of the PTF portion of the project. The list includes the status of reliability transmission upgrades (RTUs); system efficiency transmission upgrades (SETUs), which replace market efficiency transmission upgrades (METUs); public policy transmission upgrades (PPTU); and longer-term transmission upgrades (LTTUs). For completeness, the list also tracks upgrades corresponding to proposals for generator and elective transmission upgrades (ETUs). The ISO

[41] See 2023 Public Policy Transmission Upgrade Process presentation (June 15, 2023).

[42] Links to the most recent LSPs are included on the ISO's RSP Project List.

updates this list at least three times per year. Additional information on the project classifications included in the RSP Project List is available in the *Transmission Planning Process Guide*.

The ISO regularly updates the PAC on transmission upgrades, including study schedules, scopes of work, assumptions, draft and final results, and project costs. Projects are considered part of the RSP consistent with their status and are subject to transmission cost allocation (TCA) for the region. RSP25 includes updates from the June 2025 RSP Project List.

3.8.1 Reliability Transmission Upgrades

As of June 2025, the total estimated cost of reliability transmission upgrades currently proposed, planned, or under construction was approximately $0.45 billion. The upgrades are described in further detail in the Final RSP Project List and Asset Condition List and shown in Figure 3-2. Since 2002, 879 project components have been placed in service across the region to fortify the transmission system. In addition, 20 project components are currently proposed, planned, or under construction. Overall, the estimated investment in New England to maintain reliability has been approximately $13.0 billion from 2002 to June 2025. The ISO maintains a spreadsheet listing all projects for which a TCA application has been submitted, and identifies costs the ISO deemed as localized in accordance with Schedule 12C of the OATT.

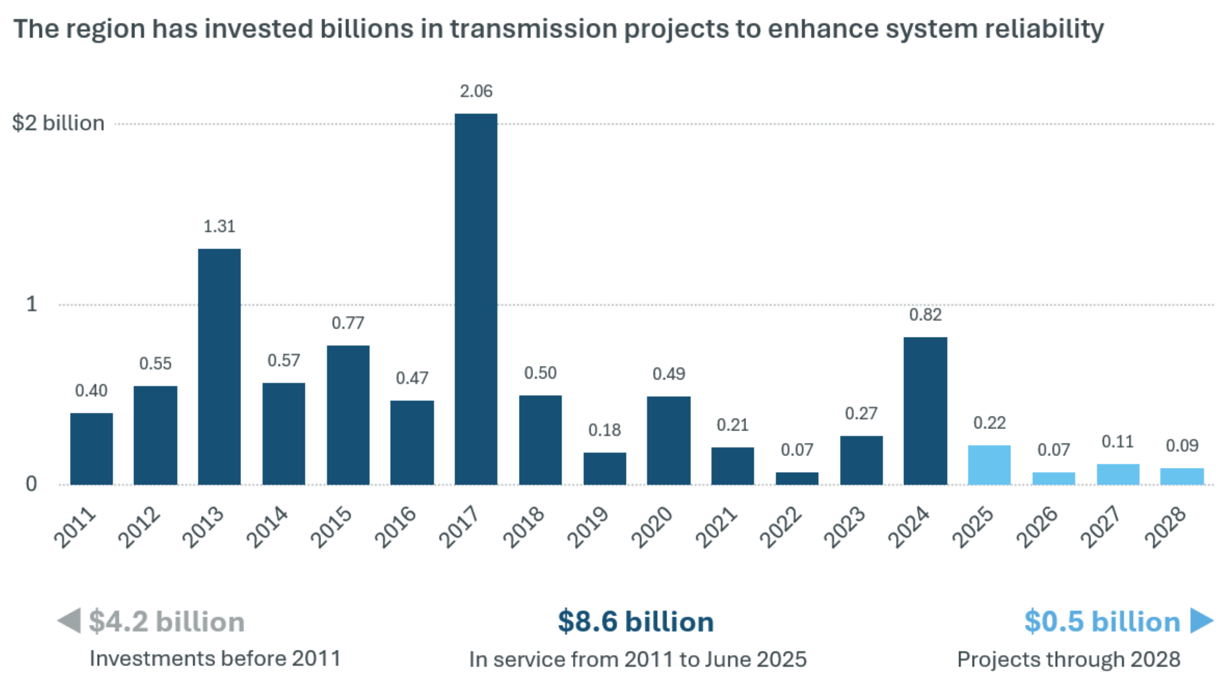

Figure 3-2: Transmission Investment by Year that Projects are In Service (Capital Costs)[43]

[43] Source: ISO New England RSP Project List, June 2025. Note: Estimated future investment includes projects under construction, planned, and proposed.

The Participating Transmission Owner (PTO) Administrative Committee provides an annual informational filing to FERC on the current and upcoming regional transmission service rates and annual updates to the ISO and the New England Power Pool. The RNS rate forecast summary for 2026 through 2030 was presented to the Transmission Committee in July 2025.[44]

Wholesale costs and the rates for residential retail power supply can vary dramatically among the states and from year to year, primarily because wholesale electricity markets and retail electricity markets are used to obtain different products. Wholesale markets reflect the short-term spot market for electric energy, whereas retail rates reflect longer-term, fixed-price contracts. The relationship between wholesale costs and retail rates also varies with the retail power procurement practices of each utility and state.

3.8.2 Transition from Market Efficiency Transmission Upgrades to System Efficiency Transmission Upgrades

To date, the ISO has not identified a need for METUs, which are primarily designed to reduce the total net production cost to supply system load. This is due in part to the following:

- RTUs have resulted in significant market efficiency benefits, particularly by reducing out-of-merit operating costs.
- The development of economic resources and fast-start resources in response to the ISO's wholesale electricity markets has also helped eliminate congestion and Net Commitment-Period Compensation (NCPC).[45]

Tariff revisions related to economic study processes have incorporated a System Efficiency Needs Scenario (SENS) to identify elements of the PTF portion of the New England transmission system that will experience congestion above a dollar threshold and evaluate whether the benefits of addressing the congestion outweigh costs in the ten-year planning horizon. If these benefits outweigh costs, the ISO will evaluate competitive solutions to the efficiency issue that would be procured as a SETU. FERC accepted the ISO's Economic Study Process Improvements Phase 2 filing (Part 1 and Part 2), which includes provisions for SETUs, in June 2025.

3.8.3 Transmission Congestion

Recent history has demonstrated that, relative to the hub locational marginal price (LMP), the regional transmission system connecting New England's load zones experiences low congestion costs.[46] At approximately $37 million in 2024, the total day-ahead ($37.9M) and real-time (–$884k)

[44] Regional transmission service is composed of regional network service (RNS) and through-or-out (TOUT) service. RNS is the transmission service the ISO provides over the PTFs, described in the OATT, Part II.B, that network customers use to serve load within the New England Control Area. The ISO's TOUT service over the PTFs allows a real-time market transaction to be exported out of or "wheeled through" the New England area, including services used for network resources or regional network load not physically interconnected with a PTF.

[45] NCPC is a payment to a supply resource that responded to the ISO's dispatch instructions but did not fully recover its start-up and operating costs in either the Day-Ahead Energy Market or Real-Time Energy Market.

[46] A hub is a specific set of predefined pricing nodes for which LMP are calculated and which are used to establish reference prices for electric energy purchases, the transfer of day-ahead and real-time adjusted load obligations, and the designation of FTRs.

congestion revenues remain small. RTUs could reduce congestion costs further, as well as reduce transmission system losses.

The highest mean annual positive difference in the congestion component of LMPs for 2024 was $0.064/megawatt hour (MWh) at the Southeastern Massachusetts (SEMA) RSP subarea relative to the hub.[47] The Northeastern Maine (BHE) RSP subarea had the highest mean negative congestion difference, at $1.21/MWh. Portions of the system remote from load centers, especially northern Maine, have higher negative loss components.

3.8.4 Transmission Improvements to Load Pockets Addressing Reliability Issues

The reliability of the transmission system depends on generators in subareas of the system that can provide contingency protections when called upon. Consistent with ISO operating requirements, these generators may be required to provide second-contingency protection or voltage support to avoid overloads of transmission system elements at key times. The local-area generating units then receive reliability payments (known as net commitment period compensation or NCPC) associated with out-of-merit unit commitments. The total cost for these reliability payments is a small portion of the overall wholesale electricity market costs in New England, which totaled $10.2 billion in 2024.

Since 2013, payments have declined significantly — the average in total payments between 2023 and 2024 ($800K) was just 1.5% of 2013's total payments. In 2024, payments totaled $900K, and no area of the system had an NCPC of more than $360K. RTUs typically improve the economic performance of the system, but upgrading transmission solely to reduce NCPC has so far not been justified.

Transmission solutions continue to be initiated in areas where proposed generating or demand resources have not relieved transmission system performance concerns. The ISO continues to study these areas, and while certain related projects are still in the planning phase, other projects which will help to mitigate dependence on generating units are already under construction and in service. RTUs were used to address these system performance concerns, which contributed to a substantial reduction in out-of-merit operating costs.

3.8.5 Required Generator-Interconnection-Related Upgrades

See Section 4.8.

3.8.6 Elective Transmission Upgrades

See Section 4.9.

3.9 Interregional Coordination

Interconnections with neighboring systems allow for the exchange of capacity and energy, facilitating access to a diversity of resources, compliance with environmental obligations, and more economic, interregional operation of the system. New England is well situated for interregional coordination, given the seasonal diversity of demand in neighboring regions,

[47] See ISO-NE's Real-Time and Historical Data for Informed Market Decisions webpage.

especially the winter-peaking Canadian provinces.[48] As our system becomes dual-peaking in the mid-2030s, this diversity of demand will diminish, and a well-coordinated interregional system will become even more crucial.

The ISO coordinates its planning activities with neighboring systems and across the Eastern Interconnection to analyze the interconnection-wide system, identify interregional transfer and seams issues, and determine whether interregional transmission solutions are more efficient or cost effective than solely regional solutions. With other entities within and outside the region, including neighboring areas, the ISO conducts and participates in studies that aim to address other common issues affecting the planning of the overall system.

The ISO participates in numerous interregional planning activities with DOE, NPCC, and NERC. The overriding purpose of these efforts is to enhance the overall reliability of the interregional electric power system.

3.9.1 Electric Reliability Organization Overview

NERC is the FERC-designated Electric Reliability Organization. In December 2024, NERC issued its annual *Long-Term Reliability Assessment* (LTRA), analyzing reliability conditions across the North American continent. This report discusses transmission additions, generation projections, and reserve capability by reliability council area. This edition of the LTRA, as with past reports, included a note regarding the heightened risk in New England, among other regions, of vulnerabilities associated with natural gas delivery to generators.

3.9.2 NPCC Studies and Activities

NPCC is one of six regional entities located throughout the United States, Canada, and portions of Mexico responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system (BPS) or bulk electric system (BES).[49,50] NERC has authorized NPCC to create regional standards to maintain and enhance the reliability of the international, interconnected BES in northeastern North America. As a member of NPCC, ISO New England fully participates in NPCC-coordinated interregional studies with its neighboring areas.

NPCC assesses seasonal reliability and, periodically, the reliability of the planned BPS. It also evaluates annual long-range resource adequacy. All studies are well-coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the ISO. The objective of the ISO assessments is to demonstrate full compliance with NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.

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[48] Interconnecting different time zones provides additional diversity. The Atlantic time zone used by the Canadian Maritime provinces is an hour later than the Eastern time zone used by New England.

[49] The six NERC regional entities are: the NPCC, Southeastern Reliability Corporation (SERC), ReliabilityFirst (RF), Midwest Reliability Organization (MRO), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

[50] NERC uses the term BES; NPCC uses BPS.

NPCC activities also include the issuance of several special reports and updating guidelines and criteria. The Northeast Gas/Electric System Study published in January 2025 assessed the future reliability risk to the NPCC BPS of a significant gas contingency during periods of increased reliance on natural gas, including electrical nonpeak/shoulder month periods.

3.9.3 Northeastern ISO/RTO Planning Coordination Protocol

Each ISO or RTO develops individual system reliability plans, production cost studies, and interconnection studies, with the potential for significant interregional impacts in mind. The Joint ISO/RTO Planning Committee (JIPC) and the Interregional Planning Stakeholder Advisory Committee (IPSAC) were established to facilitate interregional coordination and communication among ISO New England, New York ISO, and PJM.[51] JIPC has successfully implemented the Northeastern ISO/RTO Planning Coordination Protocol and the subsequent Amended and Restated Northeastern ISO/RTO Planning Protocol, which has further improved interregional planning among neighboring areas.

The IPSAC discusses the interregional planning process, regional needs, and projects meeting those regional needs, which helps stakeholders identify potential interregional solutions that may be more efficient or cost-effective than improvements discussed in the ISO/RTOs' respective regional plans. Past IPSAC discussions have addressed interconnection queue studies with potential interregional impacts and coordinated data sharing among regions related to the influx of offshore wind proposals. To date, the ISO/RTOs have not identified new interregional transmission projects that would be more efficient or cost-effective in meeting the needs of multiple regions than proposed regional system improvements.

3.9.4 Changes in Loss of Source Limit

As the interconnection of large-scale renewables such as offshore wind accelerates, project developers may seek proposals larger than 1,200 MW, and recent trends in Europe align with this possibility.[52] Both PJM and the New York ISO operate such that New England's real-time loss of source limit may be above 1,200 MW, but also allow that the limit may be reduced to 1,200 MW at any time. If a large source in New England is lost, inertial pickup would prompt increased flows through both the New York and PJM systems. Under certain conditions, these increased flows may cause voltage collapse, compromising the reliability of the New York and/or PJM systems and could, at worst, lead to widespread blackouts. The ISO's loss of source limit was established to ensure reliability in both the New York and PJM systems.

In March 2023, the ISO requested that the members of the JIPC evaluate whether the current system could already allow an increase in the minimum loss of source limit above 1,200 MW — and if it could, to what level. If the minimum loss of source limit within the existing system was below 2,000 MW, the ISO would request an additional assessment to determine the potential upgrades,

[51] The PJM Interconnection is a regional transmission organization operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

[52] To take advantage of economies of scale, wind developers in Europe are developing projects at the 2,000 MW level and higher, which will likely influence the size of offshore wind projects in the United States.

including estimated cost, necessary to support a 2,000 MW minimum loss of source limit.[53] The JIPC agreed to support the requested system evaluations and directed the ISO to lead the effort. PJM and NYISO would support the necessary evaluations to identify the feasibility and the benefits for each system.

Preliminary results of the study presented by the ISO at the May 2025 IPSAC meeting indicated an opportunity to raise the limit from the current 1,200 MW value. However, additional system risks, such as operational and planning impacts, potential impacts on required reserves, and increased risk of load shedding would need to be considered before any change to the limit is realized.

3.10 Asset Condition Process

As detailed in Section 3.8.1, $13.0 billion of reliability transmission upgrades have been placed in service in New England through June 2025, with another $0.45 billion of investment anticipated through 2028. This substantial investment has added to or improved the transmission system to serve the load in the region. This figure does not include investments needed to repair and replace aging elements of the transmission system. Most reliability transmission upgrades have involved the construction of new transmission facilities. In combination with the existing transmission facilities, this construction increases the capabilities of the system. While these new facilities work in concert with the existing system, they generally do not replace it. Many system assets are reaching the end of their useful life and require significant repair or replacement. Spending to address these concerns has increased significantly over the past few years. This spending can be reviewed in the Transmission Owner Asset Management portion of the ISO's website, a repository for all asset-condition-related PAC presentations.[54]

Although asset condition projects have not historically been under the ISO's purview (as defined in Attachment K), beginning in 2016 the ISO created an Asset Condition Update List to clarify the separation between transmission system changes driven by ISO processes and those driven by facility owner processes. The list is updated three times a year, at the same time as the RSP Project List. Since the list's creation, 467 projects have been added for a total of $11.4 billion as of June 2025. Of the 467 projects, 349 are in service, for a total of $5.5 billion. The remaining projects are conceptual, proposed, planned, or under construction. Investment in asset condition projects is illustrated in Figure 3-3.

[53] If the upgrades needed to raise the loss of source limit to 2,000 MW is cost prohibitive, the ISO would work with PJM and NYISO to determine a new limit greater than 1,200 MW that would be cost favorable.

[54] A PAC presentation is required for all asset-condition-related work where the cost estimate is greater than or equal to $5 million.

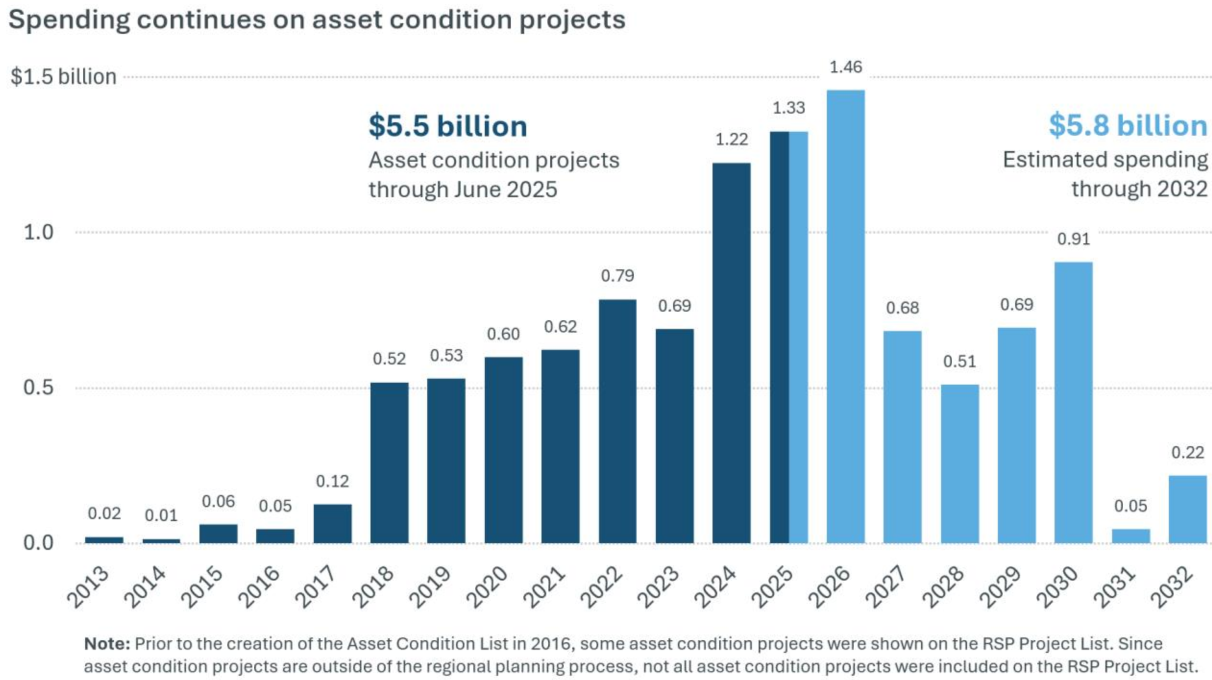


Figure 3-3: Yearly Spending on Asset Condition Projects Shown on the Asset Condition List

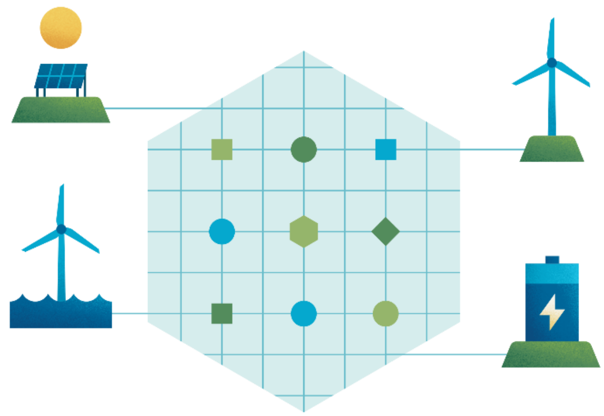
Spending on asset condition projects currently outpaces spending on reliability transmission upgrades. As a result, NESCOE has proposed several process enhancements to improve the transparency, predictability, and cost discipline of asset condition projects. These proposals were communicated through memorandums submitted to the PAC in February and July 2023.

The New England Transmission Owners (NETO) responded with the *Joint New England Transmission Owner Asset Condition Process Guide* in October 2024 and the *New England Transmission Owners' PTF Asset Database* in December 2024.[55]

Historically, the ISO has had limited involvement in the TO's asset condition projects. The ISO is supportive of additional oversight and recognizes the benefits of a robust process and independent review. Following preliminary discussions with the states and the TO sector regarding asset condition project oversight, the ISO is exploring how to take on an advisory role as an Asset Condition Reviewer. After assessing and developing a preliminary framework, the ISO plans to bring a proposal to the stakeholder community for discussion and feedback.

[55] The Joint New England Transmission Owner Asset Condition Process Guide also include appendices which covered the topics of Consistent Structure Grading Categories for PAC Presentations, Stakeholder Transparency and Review Processes for Asset Condition Projects, and PAC Presentation Guidelines.

Section 4
Resource Interconnection and Integration



To provide energy and/or capacity in New England, new resources must complete the interconnection process. The ISO studies these proposed interconnections to ensure projects meet system reliability criteria and standards for no adverse impact. This section describes the general makeup of the Interconnection Request Queue at the time of RSP25's publication, and what that composition means for the New England power grid.

In accordance with provisions of the OATT, interconnection studies include proposals for generator and ETU interconnections and supplemental transmission service for New England's grid. Studies typically consist of thermal, voltage, stability, and short-circuit analyses, with electromagnetic transient (EMT) analysis also performed for inverter-based resources. Certain factors can affect the time taken to complete each interconnection study, such as the location on the system, the extent of accumulation of requests, and the quality and finality of the modeling information provided by developers.

Proposed projects in the ISO's Interconnection Request Queue reflect the type of new generation capacity developers in the region are currently interested in building.[56] Recent years have seen large increases in wind and storage proposals as solar power's share of the queue recedes, while new natural gas proposals are near zero.

4.1 Current Interconnection Request Queue Composition

As of July 1, 2025, 156 total generation interconnection requests are being tracked in the ISO queue, totaling approximately 33,900 MW of net new generation.[57] These requests are organized by fuel type and state, and illustrated in Figure 4-1. Of these interconnection requests, 98 do not have completed system impacts studies, and so may be eligible to enter the Order No. 2023 Transitional Cluster Study described in Section 4.2. The remaining active interconnection requests have completed system impact studies, and of these, 42 have signed interconnection agreements.

[56] The ISO provides monthly updates on the status of active generation interconnection requests, via the *NEPOOL Participant Committee Chief Operating Officer (COO) Report for Monthly Updates* (Monthly COO Report).

[57] 15 of the generation queue positions are "CNR-only", which are submitted in pursuit of obtaining Capacity Network Resource Interconnection Service for projects that have already completed the steps for Network Resource Interconnection Service.

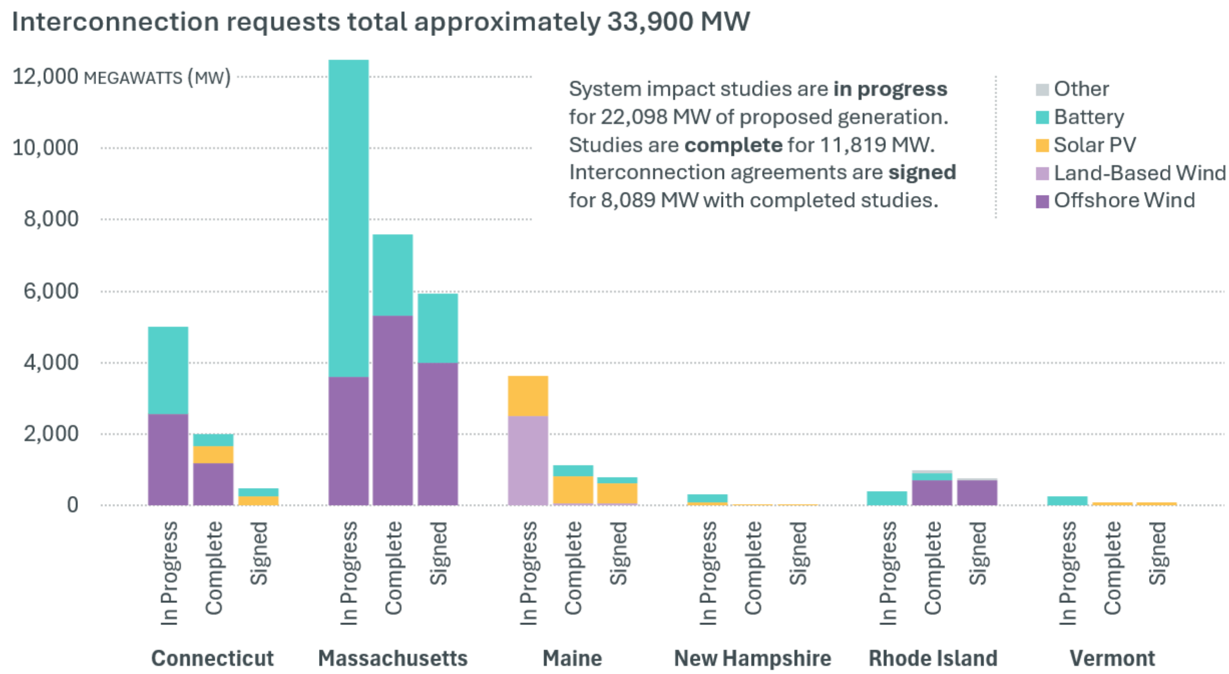


Figure 4-1: Resources Active in ISO Interconnection Request Queue, as of July 1, 2025

4.2 FERC Orders Affecting Interconnection Studies

On July 28, 2023, FERC issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, mandating significant reforms to generator interconnection procedures and agreements to ensure that interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely, and fair manner. The reforms build on the standardized procedures that FERC established in Order Nos. 2003, 2006, and 845, and are intended to address transmission interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies as those resources proliferate. On March 21, 2024, FERC issued Order No. 2023-A with some incremental reforms to the Order.

The primary elements of the Order included:

- Implementing a first-ready, first-served cluster study process
- Eliminating New England's current serial first-come, first-served study process
- Speeding up interconnection queue processing through improved processes, deadlines, and penalties
- Incorporating technological advancements into the interconnection process, including modeling and performance standards for inverter-based resources

The ISO submitted its compliance proposal to FERC in May 2024, and FERC responded to the filing on April 4, 2025, with an effective date of August 12, 2024. FERC largely accepted the ISO's proposed compliance plan, including important deviations from the FERC pro forma rules that the ISO proposed under the "independent entity variation" standard. These deviations included:

- Increasing the cluster study timeframe from 150 calendar days to 270 calendar days
- A transition process to facilitate decoupling the FCM and interconnection processes, allowing resources to achieve capacity interconnection service independent of the FCM
- A uniform set of study assumptions for all storage projects, rather than the FERC pro forma requirement to allow individual customers to specify operating assumptions for studying their devices, which would be unworkable given the New England market construct
- An extension of the cluster study process, including the higher study and commercial readiness deposits, to the Small Generator Interconnection Procedures ("SGIP") and ETU Interconnection Procedures ("ETU IP").

Although the April 4 Order largely accepted the compliance filings, it also directed further compliance with respect to some deviations from the pro forma rules that FERC determined warranted further justification or minor tariff language corrections. The ISO submitted a related further compliance filing on June 3, 2025.

Since some of the transition process rules contained dates tied to the original order date that had since passed, on May 2, 2025, the ISO, NEPOOL and PTO AC filed narrowly-scoped tariff change proposal to shift the dates associated with certain transition process activities from 2024 to 2025, for implementation starting summer 2025, with a next-day effective date. These changes were accepted by FERC in June 2025.

Based on the April 4 order and the ISO's follow-up filings, the ISO has begun to implement the new rules, beginning with the Transitional CNRC Group Study over the summer of 2025, and the Order No. 2023 Transitional Cluster Study starting in October 2025.

4.3 DER Interconnection Process

The interconnection of distributed energy resources (DERs) will continue to add complexity to the ISO-administered transmission system. More and more small resources are seeking to interconnect to the distribution system and participate in the wholesale markets.[58] As more DERs interconnect, it is essential that the ISO continue to work closely with transmission owners to ensure the proper DER interconnection process is followed and grid reliability is maintained.

In 2024, the ISO, working with the NEPOOL Reliability Committee, made a significant update to Planning Procedure 5-6 to more comprehensively describe the DER interconnection process.

4.4 Regional Integration of Inverter-Based Resources and Technologies

The ISO's planning and operating studies must account for and reflect the effect of increasing levels of inverter-based technologies on power system events. These events include voltage and frequency ride-through characteristics, control system responses and interactions with other

[58] Distribution system facilities are low-voltage electric power lines (typically < 69 kV); which can be either FERC jurisdictional or state jurisdictional. The state interconnection process will apply if a DER is interconnecting to a FERC non-jurisdictional facility.

devices, and variations resulting from changes in system strength — especially when and where fewer synchronous generators are operating on the system.

New England remains a technical leader in successfully integrating wind, PV, storage, demand response, and high-voltage direct current and flexible alternating current transmission system devices. The ISO has implemented several updates to planning, operations and the wholesale electricity markets to assist with the integration of inverter-based resources and technologies into the grid. Several of the technology developments affecting the planning of the region involve integrating grid-transformation equipment, improving operator awareness and system modeling, and using phasor measurement units.

4.5 Regional Integration of Wind Resources

The ISO's interconnection process requires accurate models of wind generator units for steady-state, stability, and transient analyses, which become particularly important in areas of the system with low short-circuit ratios.[59]

Limited transmission infrastructure in northern and western Maine is the primary obstacle to interconnecting new onshore wind resources. Current generator interconnections push this part of the transmission system to its performance limit with little-to-no remaining margin. Each new interconnection request in the area involves lengthy and complex study work, identifies significant transmission infrastructure needs, and often results in individual project developers declining to make required system upgrades, and withdrawing their proposals. To address this issue, the ISO's Cluster Enabling Transmission Upgrade methodology allows for more than one project to be grouped together to contribute to the costs of the significant upgrades. The ongoing Maine resource integration studies, for example, have identified major new 345 kV lines to allow integration of the proposed generation.

As part of the 2050 Transmission Study detailed in Section 3.5, the ISO conducted an offshore wind interconnection analysis in pursuit of two goals:

1. **Offshore Wind Relocation:** Explore connecting some offshore wind further south in the region to reduce the overloads observed on the North-South interface in the initial study.
2. **High-Level Offshore Wind Interconnection Screening:** Examine possible Points of Interconnection (POIs) to provide high-level information about their potential viability for connecting future offshore wind farms.

The study found that, if properly located, around 9,600 MW of additional offshore wind may be able to interconnect in New England without new transmission infrastructure.

4.6 Regional Integration of PV and Other Distributed Generation Resources

As noted in Section 2, continued growth in distributed PV is anticipated over the coming decade. Current PV has already caused noticeable changes to system operation and, as it grows further,

[59] Ratios under 3.0, as is the case in much of Maine, pose particular technical challenges for establishing acceptable control system performance of the interconnecting inverter-based resources.

will have a greater effect on the system's need for regulation, ramping, reserves, and voltage support. Interestingly, new flow patterns from distribution substations into (instead of out of) the transmission system when PV production is high represent a novel use of the transmission system, which has increased the need for dynamic voltage support. The ISO has engaged in various actions to examine and prepare for the effects of large-scale PV development in the region.

The ISO's current demand forecast method incorporates historical demand data on the growth and production of non-PV DERs, which, relative to PV, has so far been small. If there is large-scale growth of non-PV DERs, such as energy storage, future demand could become less predictable. Growth in such resources would present challenges like those related to the increase in BTM PV. The ISO continues to monitor this situation and actively seeks to add modern techniques to its demand forecast methodology, including big data analysis and artificial intelligence.

Distribution company owners also continuously review and improve processes and methodologies for integrating DERs. Improvements include conducting cluster analyses for resources not subject to the ISO's interconnection process, providing information on the hosting capacity of distribution circuits, and making better use of smart inverters. Electric distribution owners are also modernizing distribution system equipment to better accommodate the large-scale development of DERs.

Regulatory changes may also influence how reliability and operability standards will be met. FERC Order No. 2222, which will be implemented in November 1, 2026, directly affects resource integration and market participation by requiring Independent System Operators/Regional Transmission Organizations to remove entry barriers for DER aggregations in their wholesale markets.

4.7 Energy Storage Resources

Grid-scale, or in-front-of-the-meter, battery storage resources are integrated into the New England power system and successfully participate in regional electricity markets. Most new proposals for energy storage resources make use of inverter-based technologies. For the ISO to efficiently process interconnection requests for these technologies, requests must provide proof of appropriately robust equipment. The power system models are required to perform well in the network study analysis, and the equipment must meet established performance requirements, such as power factor, ride-through, and frequency requirements.

4.8 Required Generator-Interconnection-Related Upgrades

Apart from the larger cluster studies mentioned previously, no significant transmission system upgrades have resulted from the interconnection of generators. Most of the generator-interconnection-related upgrades are local to the point of interconnection. The RSP Project List identifies the PTF upgrades needed to accommodate new generation, and ETUs that have satisfied the requirements of the tariff.

4.9 Elective Transmission Upgrades

Various new ETUs have recently been added to the Interconnection Request Queue. Many of these are focused on delivering zero- or low-carbon resources to or within New England. The queue currently includes proposals to import energy from other regions and from offshore wind, and to increase internal transfer capabilities.

Section 5
Resource Adequacy

Part of the ISO's role in planning the power system involves identifying how much capacity the system needs to ensure resource adequacy. For a given year, this quantity is determined through the Installed Capacity Requirement (ICR) calculation, which accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The ICR directly informs the procurement of resources through the ISO's capacity market. Section 2

At the time of RSP25, the ISO is undertaking significant reform of its capacity market. These proposed Capacity Auction Reforms (CAR) are designed to better ensure power system reliability and cost-efficiency as New England's resource mix evolves.

The CAR initiative has three primary components that would take effect for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028. The first component would switch the capacity market from a forward to a prompt format — instead of three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand. The second component would switch the commitment period from one year to two seasons, which will better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season. The third component would refine how resources are accredited for capacity. To achieve a reliable and efficient clean energy transition, capacity accreditation methodologies must be updated to reflect the unique and sometimes changing characteristics of different resource types, and how their capabilities contribute to resource adequacy.

The resource mix is rapidly evolving away from resources with significant stored energy on-site, which are available for dispatch during stressed conditions, to a mix of resources with many different operating characteristics, including resources whose "fuel" is intermittent, like wind and PV.

The ISO's updated capacity accreditation will allow all resources — some of which may have inherently different reliability contributions per MW toward resource adequacy than others — to sell the same uniform product in the capacity market. This process should define a capacity metric that can be used across resources. This metric would allow for more "apples-to-apples" comparison between the accredited capacity of different resources.

The ISO expects to file new tariff rules to implement the CAR project for the 19th Forward Capacity Auction (FCA 19) for the 2028/2029 capacity commitment period (CCP). As of RSP25, these rules are not yet final. As a result, resource adequacy analyses in this section that include CCPs beyond FCA 18 are based on existing rules. Details on how the CAR project could affect future ICR values and resource accreditation are available in the materials presented at the Markets and Reliability Committees and the CAR initiative webpage.

The ISO projects sufficient resources to meet the resource adequacy planning criterion for New England through the 10-year planning horizon. This projection assumes no additional retirements, as well as the successful commercialization of all new resources that cleared the FCM in FCA 18. However, the pending CAR project could significantly change how New England resource adequacy is assessed.

The DOE's recent Resource Adequacy Report, *Evaluating the Reliability and Security of the United States Electric Grid*, examined the risk of shortfalls for regions of the U.S. through 2030, and found that ISO New England maintained adequacy throughout the study period.

5.1 Systemwide Installed Capacity Requirements and Future Resource Outlook

Under the current market rules in place through FCA 18, the ISO develops the ICR in consultation with NEPOOL and other interested parties through an extensive stakeholder process. The ISO vets the assumptions used to develop the ICR with the New England stakeholders, and the Power Supply Planning Committee reviews the values developed by the ISO. The Reliability Committee and the Participants Committee then review, discuss, and vote on the values before they are filed with FERC.

Figure 5-4 shows the net ICR for FCA 16 through FCA 18. The ICR is based on a system that has a LOLE of 0.1 days/year. The net ICR is met by the amount of cleared capacity in each of the auctions.

CCPs starting in June 2028 through the end of the planning horizon will be affected by the proposed CAR project. For these CCPs, calculation of a representative ICR based on the current FCM framework would not provide useful information. The ISO determined the future resource outlook by deriving the system's loss of load expectation (LOLE) values based on the available resource mix at the conclusion of FCA 18.

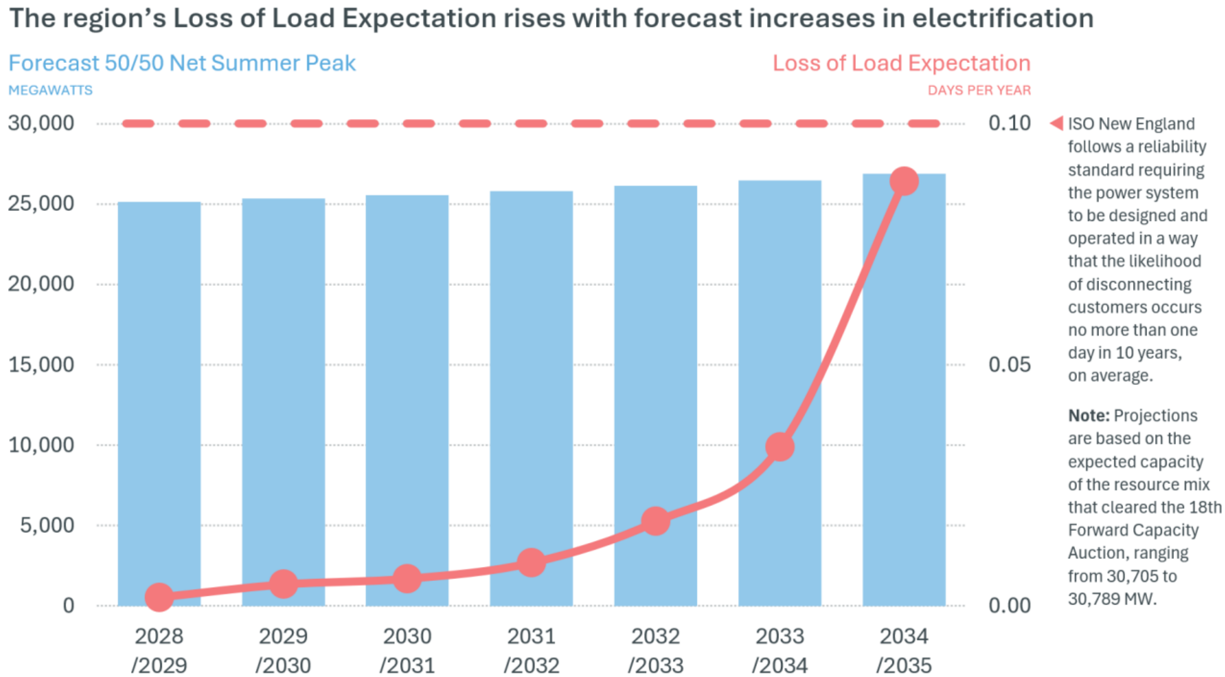


Figure 5-1: New England LOLE Values and Resulting Reserves (days/year, %)

Figure 5-1 shows the system's LOLE values for the remainder of the 10-year horizon. While the LOLE remains below the 0.1 LOLE reliability criterion for the entire period, a steady rise is observed towards the later years, reflecting the effect of a growing load forecast without the addition of resources post FCA 18.

5.2 Local Resource Requirements and Limits

The ICR addresses New England's total capacity requirement using the assumption that the system at large has no transmission constraints. In reality, certain subareas are limited in their ability to import or export power. To address the impacts of these constraints on subarea reliability, the ISO determines the local sourcing requirement (LSR) and maximum capacity limit (MCL) for certain subareas. An LSR is the minimum amount of electrical capacity that must be located within an import-constrained capacity zone to meet the net ICR. An MCL is the maximum amount of electrical capacity connected in an export-constrained capacity zone that can be used to meet the net ICR. Before each FCA, areas that meet certain objective criteria for zonal modeling are designated as capacity zones and assigned an LSR or MCL.[60]

[60] LSRs and MCLs are based on network models using transmission facilities that will be in service no later than the first day of the relevant CCP. Capacity zones are developed pursuant to ISO Tariff, Section III.12.4.

Figure 5-2 shows the LSRs and MCLs for capacity zones for the last three auctions. Values have remained fairly consistent from FCA 16 through FCA 18.[61] Southeast New England (SENE) required an LSR for FCA 16, which was not modeled for FCA 17 and beyond due to reduced load and improved transmission in the region. The Maine and Northern New England (NNE) zones have required an MCL since FCA 14.

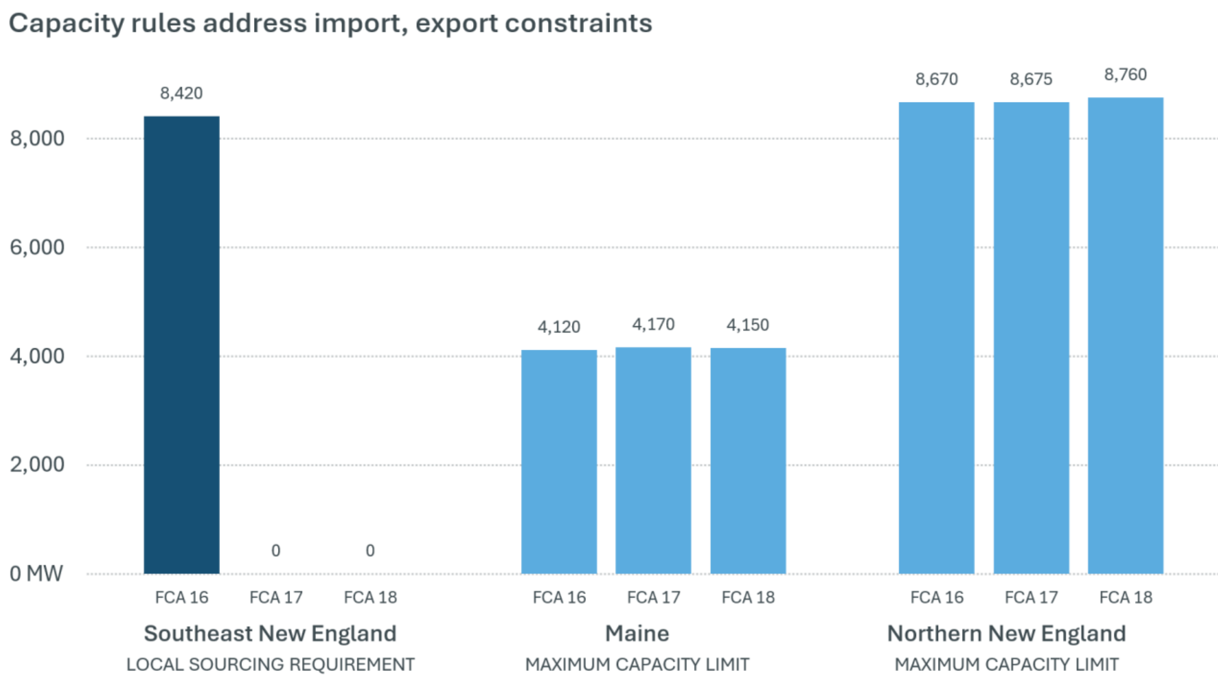


Figure 5-2: Actual LSRs and MCLs for FCAs 16–18

5.3 Tie Benefits and Capacity Imports

Interconnections with neighboring regions provide opportunities for exchanging capacity, energy, reserves, and mutual assistance during capacity shortage conditions. The tie-reliability benefits reflect the amount of mutual assistance assumed to be available from interconnections with neighboring control areas in the event of a capacity shortage in New England. These benefits lower the ICR. Capacity imports help New England meet the ICR and enhance competition in the capacity and energy markets. Imports also provide resource diversity, and imported energy produced by renewable resources can lower regional generation emissions.

The historical tie benefits and imports from the last three FCAs are shown in Figure 5-3.[62] Tie benefits have remained relatively constant over the last three FCAs. Imports cleared in the last

[61] FCA 16 figures, that cover the 2025/2026 CCP, are derived from calculations performed for the third annual reconfiguration auction for that CCP; FCA 17 figures, that cover the 2026/2027 CCP, are derived from calculations performed for the first annual reconfiguration auction for that CCP; FCA 18 figures, that cover the 2027/2028 CCP are derived from calculations performed for the annual auction.

[62] See footnote 59.

three auctions have been more volatile, with significantly fewer imports clearing in FCA 17 and 18. Additionally, different values cleared for summer and winter in FCA 18.

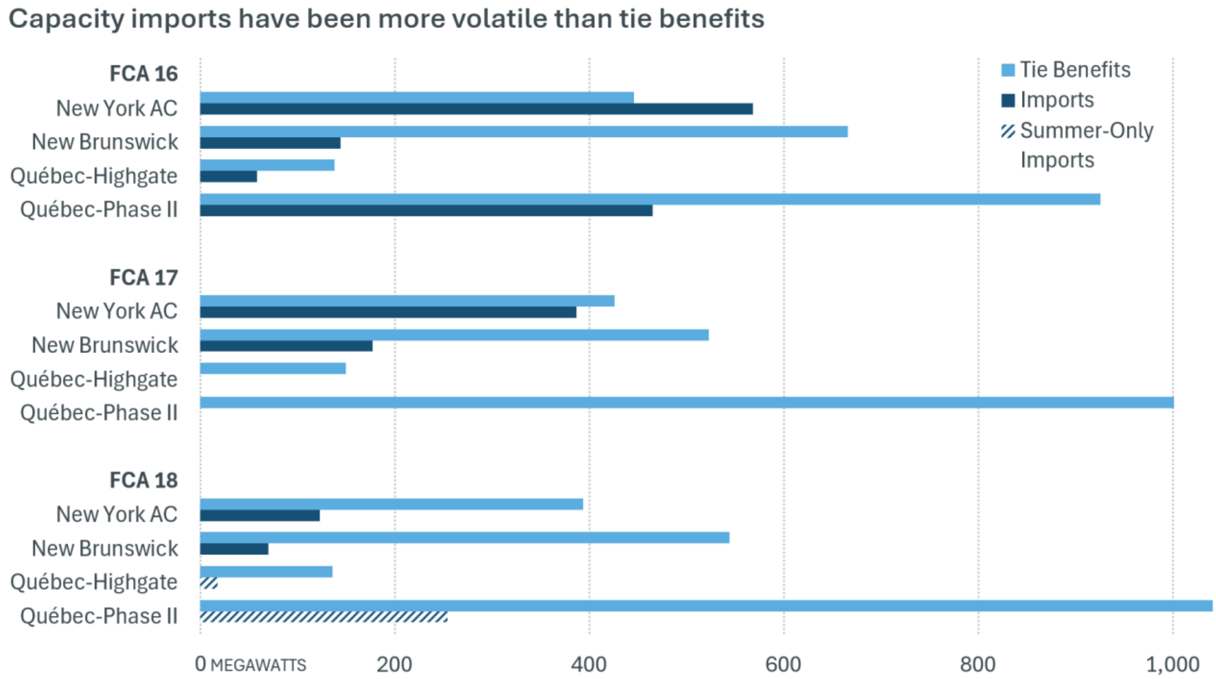


Figure 5-3: FCA 16–18 Tie Benefits and Imports

As part of the CAR project, the ISO will be incorporating seasonality into tie benefit forecasts. The ISO is reviewing its methodology in discussion with stakeholders to ensure tie benefit contribution is sufficiently reflected in resource adequacy studies.

5.4 Capacity Supply Obligations from the Forward Capacity Auctions

Figure 5-4 illustrates the results of FCA 16 through FCA 18 and provides the capacity supply obligation (CSO) totals at the conclusion of each auction.[63]

[63] See footnote 59.

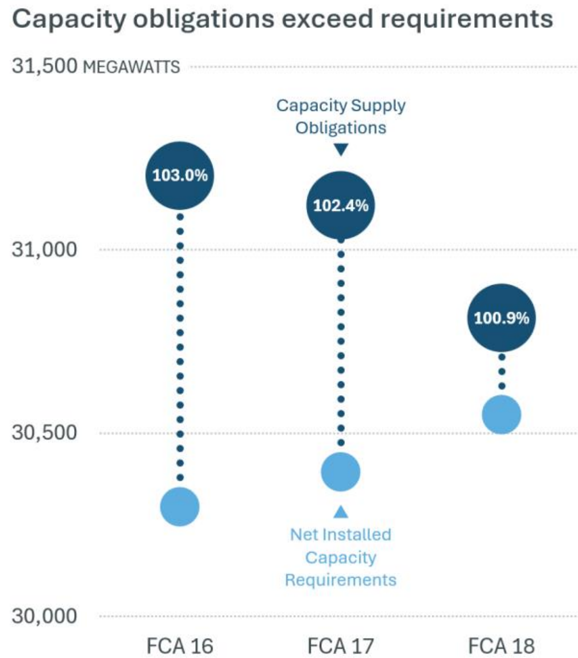


Figure 5-4: Summary of FCA Net ICR and CSOs

As illustrated, the net ICR remained fairly constant from FCA 16 through FCA 18, close to 30,500 MW.

Figure 5-5 illustrates, by resource type, the quantity of new capacity procured during the last three FCAs. Imports declined significantly in FCA 17 compared to historical procured amounts. New demand response has continued to decline over the last three auctions, with very little active demand capacity resources clearing in the two previous auctions.

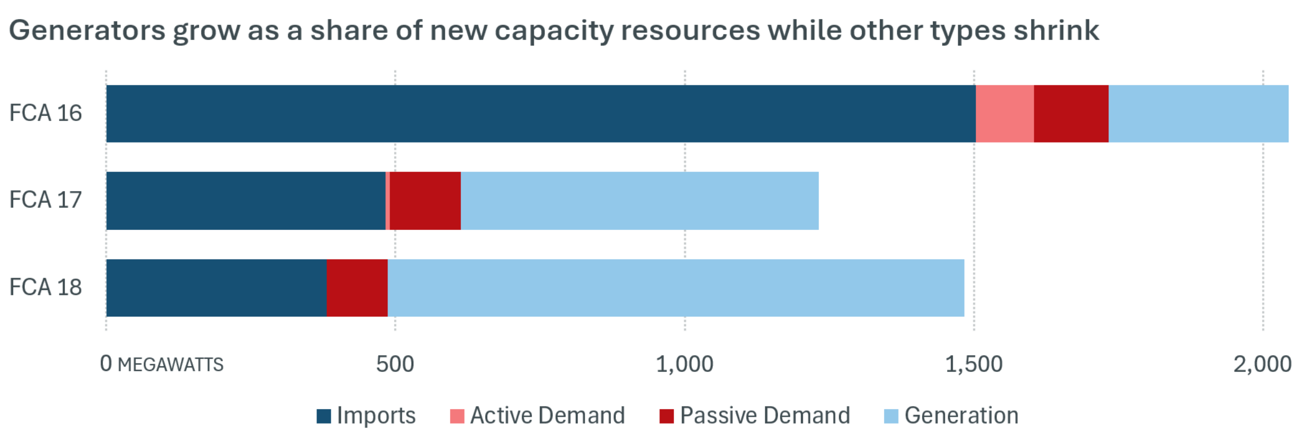


Figure 5-5: New Capacity Procured during FCAs 16–18

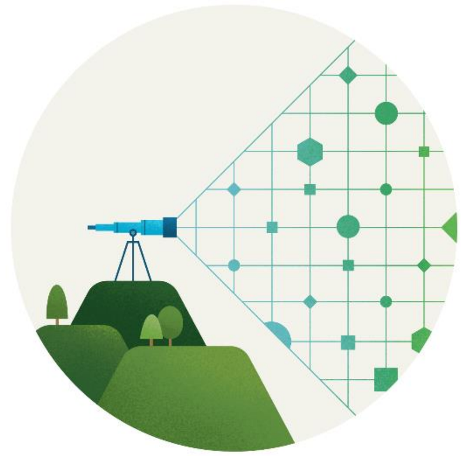
5.5 Energy Adequacy

In 2022-2023, the ISO worked with the Electric Power Research Institute (EPRI) on a probabilistic energy-security study to examine how extreme weather events might impact energy adequacy in New England. The results helped develop the Probabilistic Energy Adequacy Tool (PEAT), which the ISO uses to assess operational energy-security risks associated with extreme weather events.

Using results from PEAT, the ISO is working with regional stakeholders to establish a Regional Energy Shortfall Threshold (REST) that determines an acceptable level of regional reliability risk by assessing the magnitude and duration of energy shortfalls. Once established, REST will be used to develop specific regional solutions to reliability risk, which could range from market designs to infrastructure investments to dynamic retail pricing and responsiveness by end-use consumers. The parameters of the metric are currently under review with stakeholders.

This initiative is a collaborative opportunity for industry leaders and regional stakeholders to learn about how future extreme weather events may affect the evolving power system, and to prompt thinking about how best to prepare. Variable and extreme weather is a key factor affecting resource (i.e. energy) availability, demand patterns, and related reliability concerns.

Section 6
Economic Studies



Attachment K of the tariff instructs the ISO to conduct needs assessments as they relate to the regional system planning process. These assessments evaluate whether changes to the power grid might reduce total production costs or reduce congestion on transmission lines. These types of needs assessments are also known as economic studies.

At a high level, the ISO's economic studies provide the region with information and data on possible evolutionary changes to the power grid. Changes to the grid impact the public, and the implications of these changes must be explored and shared widely to educate and inform. Recent economic studies have focused primarily on how the future grid might reliably and cost-effectively achieve state goals for reducing emissions.

Since RSP23, the ISO released the EPCET study, which piloted the first phase of tariff changes to the economic studies process. The second phase of the changes were accepted by FERC in June 2025. The first formal economic study under the tariff changes, the 2024 Economic Study, began in January 2024, with completion expected by December 2025.

Further detail on economic studies including EPCET and the 2024 Economic Study can be found on the Economic Studies website.

6.1 Economic Planning for the Clean Energy Transition

Following the acceptance of the first phase of economic study tariff changes with FERC, the ISO performed the EPCET pilot study. The study was a "dry run" of the tariff changes, and included three repeatable scenarios (Benchmark Scenario, Market Efficiency Needs Scenario, and Policy Scenario). The EPCET study report was published in October 2024.

The EPCET study produced several key findings, many of which converged on a common theme: designing the power system of the future requires balancing reliability, economic efficiency, and carbon-neutrality. Given current technology and market structures, no single existing scalable resource type is highly reliable, inexpensive *and* carbon neutral, and future planning will require considering the tradeoffs among these three factors.

6.1.1 Most paths to a low-carbon grid involve high variability in supply and demand

Today's electrical grid experiences only modest variations in peak annual demand from year to year, allowing for efficient planning for a limited range of possible outcomes. In the future, however, electric heating will shift annual system peak demand from summer to winter. The magnitude of the annual peak will vary dramatically from one year to the next, depending on how cold or how mild a winter the region sees.

As penetration of wind and solar resources increases, supply will also become much more weather-dependent, and thus much more variable. At times of low wind and solar generation, a renewable heavy system may not produce enough energy to satisfy demand. Most weather years in the Policy Scenario analysis experience such stretches — and in these stretches, stored fuels meet demand. Figure 6-1 shows EPCET's projected variation in peak demand between 2023 and 2050.

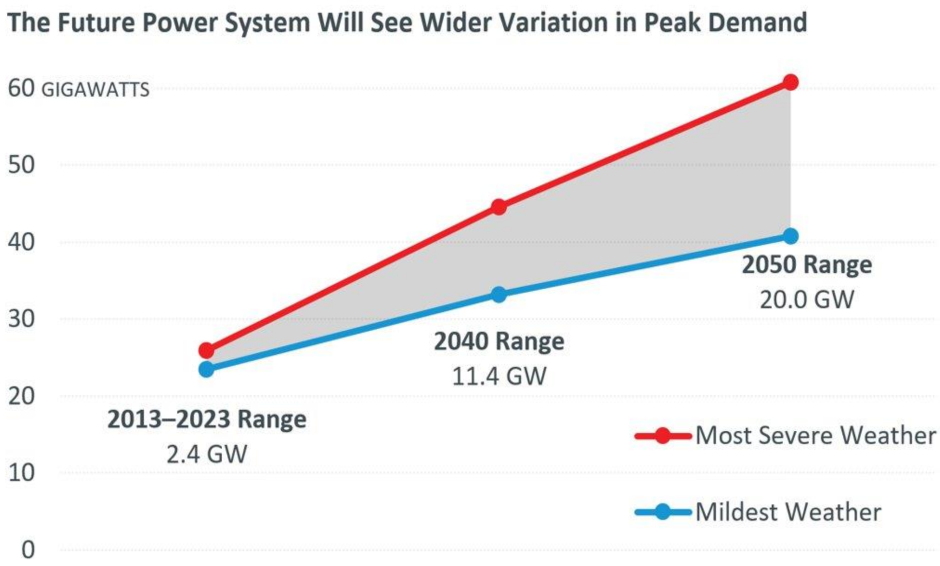


Figure 6-1: Projected Variation in Peak Demand, 2023 to 2050

6.1.2 Increased variability will require vastly different supply levels from year to year

As variability in peak demand increases, the system will rely on certain dispatchable resources to maintain reliability — but these resources will run less and less frequently over time. The New England power grid will need to reliably serve peak demand for the most severe winter conditions the region might see. But despite the possibility of severe cold, most winters are likely to be milder, with significantly lower peaks. As a result, some resources needed to maintain reliability during the harshest conditions may only run once every few years.

6.1.3 Emissions reduction will be seasonal. Some months will decarbonize years before others

Decarbonization in the later years of modeling is highly correlated with the season, and certain times of the year are expected to decarbonize much faster than others. Modeled seasons decarbonize in the following order: spring, fall, summer, and, finally, winter. Notably, spring and fall will decarbonize long before winter. This trend is driven by two factors: seasonal demand and seasonal intermittent renewable generation. Demand is lower in spring and fall due to milder temperatures, and higher in summer and winter, when energy is used to cool or heat buildings. Electric vehicle charging also requires more energy in colder months. Similarly, wind and solar have different output levels in different seasons. Winters tend to be windy, but less sunny, while summers tend to be sunnier, but less windy. Spring and fall tend to be moderately sunny and windy.

6.1.4 Renewable-only build-outs may be vast, and later additions of renewable resources could have diminishing environmental and economic returns

As variability increases, larger and larger build-outs of wind, solar and batteries will be required to ensure reliability throughout the year. These build-outs will increase costs and could require significant amounts of land-based or offshore areas for siting. As more hours of each year decarbonize, new renewable additions will have less impact on reducing carbon emissions, particularly in the spring and fall months that are expected to decarbonize first. A 2050 resource mix that includes current resources and adds a build-out of wind, solar, and short-term battery to meet emissions goals and accommodate increased electrified demand would require approximately four times the capacity of today's system.

6.1.5 Higher variability will increase the value of current and future dispatchable resources, including long-duration storage

Since increasing variability will require a critical fleet of dispatchable resources that can quickly meet demand whenever it is needed, planned retirements of fossil fuel generators in the coming decades may affect system reliability. Longer-duration storage that provides dispatchability will help support reliability, but will not solve all challenges. Seasonal storage that could charge in spring and fall for deployment in winter would be particularly valuable.

6.1.6 Current revenue structures may not adequately compensate resources for their value to the future grid

The expected increase in variability and the critical but sporadic need for dispatchable resources to ensure reliability will change the grid dramatically, which will affect the performance of some elements of the current grid economy. EPCET's Stakeholder-Requested Sensitivity explores how both current markets and alternative market structures and compensation strategies perform under highly variable conditions. Results show that as deep decarbonization accelerates, the functionality of power purchase agreements (PPAs) changes, as does the size of the energy market. One key result illustrates that, assuming today's PPA strategies hold, by the mid-2030s a new renewable resource could become unprofitable within five years.

6.1.7 Firm, dispatchable, zero-carbon generation could help address challenges

Previous sections have emphasized the importance of dispatchable generation in a highly variable system. To entirely avoid generation that burns fossil fuels, the future system will require vast quantities of seasonal storage, or a firm supply of zero-carbon fuel. Although the technology for zero-carbon dispatchable generation exists, the expense of necessary retrofits to existing generators, fuel delivery upgrades, and an uncertain storage and supply chain may be significant barriers to deployment at scale. A technology or fuel that requires minimal generator modification and little to no pipeline/storage upgrades could be most cost-effective. Options for renewable fuels may include synthetic natural gas (SNG), hydrogen, biodiesel, renewable diesel, or others. EPCET explored the hypothetical use of SNG and small-modular reactors (SMRs) as candidates for zero-carbon dispatchable generation. Results illustrated in Figure 6-2 show that including these technologies in the future grid may help reduce the size of the buildout.

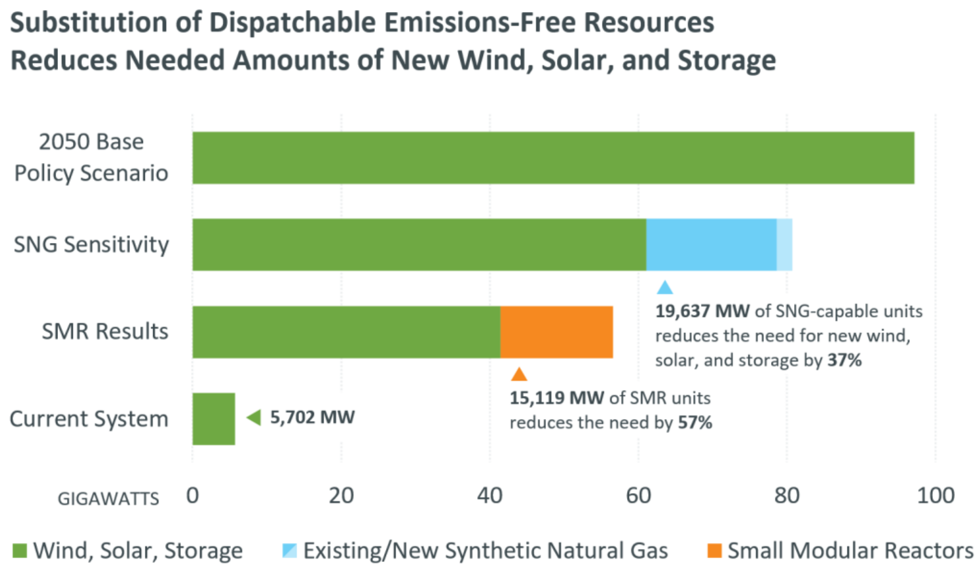


Figure 6-2: Reduction in 2050 Buildout Based on Additions of SNG and SMR

6.1.8 Difficult minimum load conditions, energy adequacy challenges, and potential system congestion may appear by the 2030s

Grid reliability must be maintained during duck curve days, when BTM PV causes demand for grid electricity to drop significantly during daylight hours. These days are occurring with greater frequency in spring and fall. With its large quantities of BTM PV and electrified heating and transportation, EPCET's modeled 2032 system experiences some duck curve days with unprecedented minimum net loads. Minimum load conditions are particularly relevant to the operational realities of less flexible baseload resources like the region's existing nuclear plants.

EPCET's 2032 analysis also forecasts challenges related to energy adequacy. In today's grid, heating drives demand for natural gas, which results in stretches of time when some electric generators cannot obtain gas. During these periods, the region relies on stored fuels to meet electricity demand. Though winter gas constraints are expected to recede as more natural gas heating is displaced by electric heat, the timing and pace of this regional conversion remains uncertain. If the conversion of fuel oil and wood heating to electric heat pumps significantly outpaces the conversion of natural gas heating to electric heat pumps, New England could see additional electricity demand from heating without additional natural gas availability.

6.2 Economic Study Process Changes

The ISO has historically conducted economic studies under Attachment K of its tariff, which permits stakeholders to request studies every April 1. While this process allowed for many useful studies, it also required stakeholders to provide a whole suite of assumptions for, at times, a single question. Recent studies have averaged 18 months, and this timeline often meant that the previous year's study was unable to inform the current year's requests, while the overlap strained ISO resources. Some requests were very narrow while others were quite broad. The tight timeline also limited the ability to coordinate with neighboring regions or answer more complex questions.

Year-to-year and study-to-study variations in assumptions limited any ability to observe trends over multiple years or make comparisons between studies. Stakeholders indicated interest in moving beyond the capabilities of the initial studies; current production cost modeling with stakeholder-led assumptions is of less interest. Stakeholders have asked the ISO to take more leadership in identifying necessary studies, and want to see more variety in analyses, further integration of various models, and an eye toward "big picture" observations.

In response to these lessons learned and stakeholder feedback, the ISO altered its study framework to include three repeating reference scenarios in addition to a stakeholder-requested scenario and sensitivity requests. The reference scenarios cover the baselines of current plans for the clean energy transition. Using the same reference scenarios, updated with the region's most recent projects and policies on a repeating cycle, will provide more insight into system trends, and should aid stakeholders in formulating requests for more targeted analysis based on those trends. Additional benefits of the economic study process changes include:

- A longer timeline, allowing for more detailed modeling (for example: move from zonal to nodal simulations)
- Better alignment of economic studies with other studies within system planning, providing predictable and consistent usage of internal ISO resources
- Opportunities to explore new modeling methods for the evolving grid during the study cycle (e.g., electric/gas co-simulation during winter peaks, probabilistic outage modeling, etc.)
- The opportunity to incorporate neighboring regions' detailed models in simulations

The process changes also follow models of repeated studies used by New York ISO and other regional operators.

To reflect these changes, in January 2023, the ISO filed tariff revisions with FERC for Phase 1 of the economic studies process. These changes were approved in March 2023 and have been implemented in the 2024 Economic Study.

A second round of tariff revisions, which will provide additional clarity surrounding the System Efficiency Needs Scenario (previously the Market Efficiency Needs Scenario), were filed with FERC in April 2025, and accepted in June 2025. The changes provide a clear and distinct process for the conduct, metrics used, and identification of a system efficiency need and the process to evaluate solutions.

Under the new process, the ISO will run a base SENS model and identify and rank congestion points. If any congestion points show production cost savings of $4.3 million per year or more, the process will move forward to an RFP. The ISO will identify the minimum beneficial upgrade, and QTPSs will submit their proposals. The ISO will calculate a benefit-to-cost ratio (BCR) for each project, and evaluate three potential benefits: production cost savings, reduced transmission losses, and avoided transmission investment. If more than one project has a BCR greater than one, the ISO will use evaluation criteria detailed in Attachment K section 17 to select the preferred solution. If only one project has a BCR greater than one, that project will be the preferred solution.

6.3 The 2024 Economic Study

Work on the 2024 Economic Study began in January 2024, and completion is expected by December 2025. This study continues the work of EPCET by modeling the repeatable scenarios defined by the recent tariff changes, exploring possible future buildouts of the New England grid. Publication of the study's report is expected by September 2025 and will focus on the Policy and Stakeholder Scenarios. Analysis of the System Efficiency Needs Scenario will continue through December 2025. Updates to the study process since EPCET include the following:

Increased transparency:

- As part of the LTTP process (see Section 1), the ISO has released a public version of the Benchmark Model and two other public models. This has included collaborative discussions and feedback with stakeholders over the model's content.
- Publication of the Economic Studies Technical Guide has led to additional discussion and feedback from stakeholders, and improved the overall understanding of economic study models.

Inclusion of new technologies:

- The ISO has set clear limits for when new technology types will be included in the base-case policy scenario capacity expansion model. This study's base-case policy scenario includes SMRs and iron-air batteries for the first time.
- The ISO has tested new modeling features to better model these new resources, including optimized charging profiles and energy storage targets for long duration energy storage.

Modeling improvements:

- As a result of discussions with stakeholders during EPCET, the SENS model includes a Northeast Power Coordinating Council (NPCC) interregional model, which provides insight into possible future interchange trends.
- The ISO has developed modeling techniques to optimize flexible load, which helps explore demand response strategies like shifting EV charging to non-peak times.

Identification of multiple decarbonization pathways:

- The study models a wide variety of possible future scenarios, exploring a wider scope of possible pathways to a decarbonized system.
- Land-based wind emerges as the most cost-effective tool for decarbonization in the short term, aligning with the recent LTTP RFP (see Section 1), which prioritizes the interconnection of more land-based wind in northern Maine.