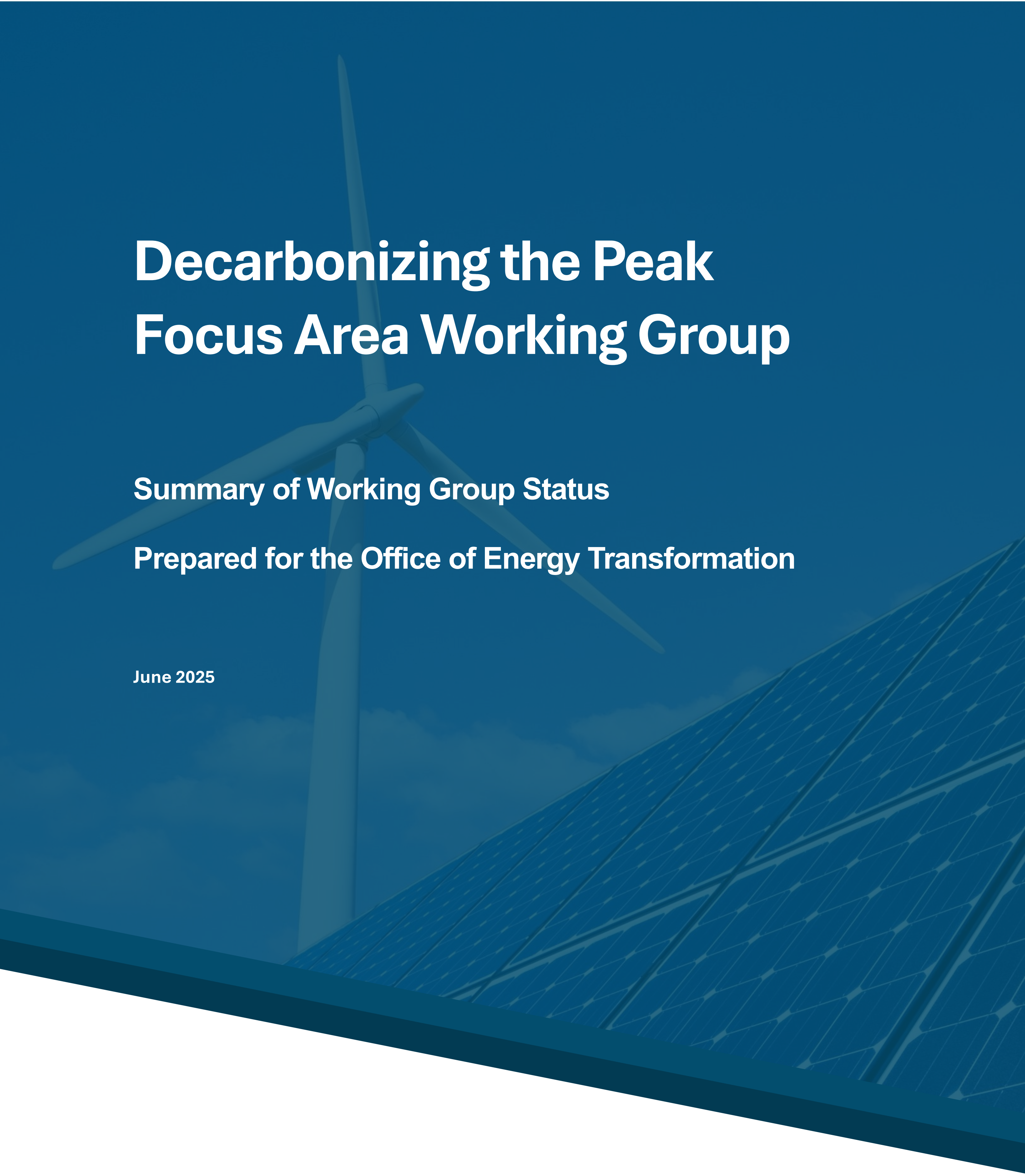

Decarbonizing the Peak Focus Area Working Group

Summary of Working Group Status

Prepared for the Office of Energy Transformation

June 2025

Energy+Environmental Economics

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Acronym Definitions

Acronym	Definition
CECP 2050	Clean Energy and Climate Plan for Year 2050
CES	Clean Energy Standard
DPU	Department of Public Utilities
DTP	Decarbonizing the Peak
EELP	Harvard University's Environmental and Energy Law Program
ELCC	Effective Load Carrying Capability
EMT	Everett Marine Terminal
ESED	Enabling Sustainable Economic Development
ETAB	Energy Transformation Advisory Board
FAWG	Focus Area Working Group
FTT	Financing the Transition
GCC	Georgetown University's Climate Center
ISO-NE	Independent System Operator of New England
OET	Office of Energy Transformation
SIS	Surplus Interconnection Service

Executive Summary

Massachusetts' commitment to net-zero emissions by 2050 requires transforming how the state produces and uses energy, with a central focus on reducing fossil fuel reliance. Since its inception in 2024, the Office of Energy Transformation (OET), with support from its Energy Transformation Advisory Board (ETAB) and Decarbonizing the Peak Focus Area Working Group (DTP FAWG), have been evaluating the technical, policy, and economic pathways for reducing reliance on fossil-fueled peaker and combined heat and power (CHP) facilities. With input from working group members and expert consultants, the DTP FAWG completed Phase I in June 2025. This report summarizes that progress—focusing on the role of peaker and CHP facilities and the resource adequacy needs of the regional electric grid—and outlines recommended next steps.

Phase I focused on building a common understanding among participants of the role played by peaker and CHP facilities in maintaining grid reliability. Peaker resources operate infrequently but are critical during peak conditions, including extreme weather and supply shortfalls. However, they also contribute to greenhouse gas emissions and local air pollution. CHP facilities present a more complex challenge due to their high operating efficiency and dual role in meeting both thermal and electric loads, often in institutional or industrial settings. The working group reviewed facility-specific and system-wide data, as well as examined market design, policy frameworks, and current compensation structures, and their influence on facility decision-making and investment.

Direct participation from four Massachusetts facilities—West Springfield (retired and converting to storage), Pittsfield (active peaker), Canal Station (large oil and gas facility), and Tufts University CHP—allowed the FAWG to better understand site-specific conditions and constraints. These case studies demonstrated that factors such as site control, interconnection, and proximity to load heavily influence potential pathways to replacement or reduced reliance.

To support future decision-making, the FAWG developed a screening assessment framework for evaluating technology and policy alternatives. This framework includes criteria related to emissions, environmental impacts, costs, feasibility, community impacts, and substitutability for peakers. Subgroups of the FAWG refined this tool by focusing on demand-side measures, emissions profiles, costs, and community impacts. A series of expert presentations—from national labs, research institutions, organizations, and developers—is complementing this work by strengthening the technical foundation in areas such as renewable fuels, long-duration energy storage, and surplus interconnection opportunities.

As the working group proceeds with Phase II and III, the DTP FAWG will advance screening of potential alternatives through the assessment, perform portfolio-level modeling of reliability impacts, prioritize facilities for near-term action, and produce recommendations. Addressing barriers to implementation—particularly permitting, interconnection, and site redevelopment—will be essential. Leveraging the assessment and working group discussions, the DTP FAWG will then deliver actionable recommendations to the ETAB that help reduce fossil fuel reliance, while maintaining reliability and affordability for the Commonwealth.

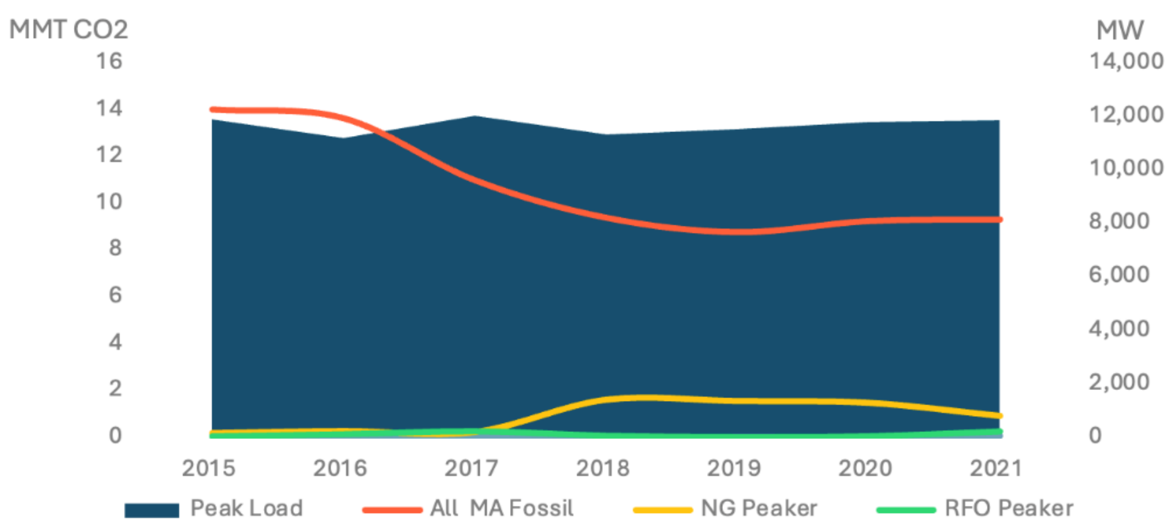
Introduction

Motivation and Context

The Massachusetts Department of Public Utilities (DPU) order in Docket 20-80 established a regulatory framework that advances the Commonwealth's transition away from fossil fuels, aligning with Massachusetts' broader aim of achieving net-zero carbon emissions by 2050. Toward this aim, the Office of Energy Transformation (OET) was established on May 1, 2024, to enable the hands-on execution of the Commonwealth's clean energy transition toward electrification, which is expected to be the primary energy delivery system for the state by mid-century. As the first office of its kind in the country, OET is focused on three key areas: the shift from gas to electric systems, ensuring electric grid readiness, and supporting a just and equitable transition for workers, businesses, and communities.

Figure 1 provides some historical context on key dynamics that have shaped Massachusetts' electric sector over the last several years. From 2015 to 2021, total CO_2 emissions from the electricity sector had steady declines, driven by a shift toward cleaner generation. This downward emissions trend occurred alongside relatively stable peak demand, with reliance on peaker plants growing slightly. While peaker plants ran more frequently during this period, they did so increasingly on natural gas rather than oil, reducing their emissions intensity, with their operational flexibility playing an important enabling role in supporting the integration of variable renewable resources by filling "gaps" during periods of low renewable output. This nuanced trend underscores the goals of the OET to ensure that its efforts lead to overall grid decarbonization while ensuring reliability and affordability are maintained.

Figure 1. 2015-2021 MA Emissions



Organizational Structure Supporting the OET

In September 2024, OET established the Energy Transformation Advisory Board (ETAB or Advisory Board), a diverse stakeholder body, to advise the OET and its work. The ETAB includes representatives from labor, business, investor-owned and municipal utilities, environmental justice communities, consumer advocates, tribal communities, real estate and housing, clean energy technology, power generators, fuel providers, local and state officials, financial institutions and investors, academia, health care and hospitals, planning agencies, and conservation groups, among others. The ETAB plays a central role in shaping and guiding OET and its working groups as they assess technical needs, identify barriers, and recommend actions.

To support the ETAB in its mission, OET concurrently created three Focus Area Working Groups (FAWGs), and subsequently added a fourth, each tasked with advancing one element of the Commonwealth's clean energy transition. FAWGs bring together a wide range of participants, including those represented on the ETAB, along with other stakeholders from local community and advocacy groups, private individuals, technology providers, building and facilities managers, economic and environmental consultancies, and others. Participation is open, but members must be affirmed by the ETAB and are expected to serve for a one-year term. FAWG participants are subject matter experts or senior staff with decision-making authority in their organizations, if representing an organization. Each working group meets at least every two months, under Chatham House rules, with additional meetings held as needed by workstream teams.

Each FAWG is responsible for executing workplans approved by the ETAB, assessing current conditions, identifying and evaluating alternatives, and making recommendations. Workstreams within each FAWG organize the more detailed technical or policy work, and participants self-select into these smaller teams based on interest or expertise.

Four FAWGs have been launched to date:

- Transitioning Away from the Everett Marine Terminal (EMT)
- Enabling Sustainable Economic Development (ESED)
- Financing the Transition (FTT)
- Decarbonizing the Peak (DTP)

The EMT FAWG is focused on reducing and ultimately eliminating reliance on the Everett Marine Terminal LNG facility in alignment with DPU Order 20-80 and the state's climate mandates. The FTT FAWG is evaluating funding and cost-recovery models for electric infrastructure investments, with the goal of identifying new approaches that can support decarbonization and electric demand growth, while minimizing customer bill impacts. The ESED FAWG is exploring the concept of establishing clean energy-ready economic development zones to enable businesses to grow in Massachusetts while aligning with the state's climate goals.

The DTP FAWG is charged with identifying and demonstrating ways to reduce and eliminate fossil fuel use from the state's highest-emitting generators, especially peaking units and combined heat and power (CHP) facilities. In support of the electric sector limits set in the 2050 Clean Energy and Climate Plan (CECP), the group is exploring both demand-side and supply-side alternatives for meeting peak system needs. Initial workstreams include characterizing the role and economic incentives of existing peakers and CHP units, assessing feasible alternatives, assessing implementation alternatives, and discussion of potential equity impacts.

Supporting the OET, ETAB, and FAWGs are a team of consultants who guide and advise the stakeholder led process. Consensus Building Institute (CBI) organizes and facilitates key activities while helping to ensure that all stakeholders have a voice and the opportunity to engage. As a neutral third-party, Energy and Environmental Economics (E3) provides expert insights and technical analysis related to the New England electric grid. Harvard University's Environmental and Energy Law Program (EELP) and Georgetown University's Climate Center (GCC) offers expert knowledge and context related to relevant federal and state policies. Additionally, Analysis Group brings expert financial and regulatory analyses, while Groundwork Data provides key insights into the role of natural gas in the energy transition and broader operations of the Commonwealth's and region's natural gas systems.

Report Contents

Focusing on the DTP workstream, this report serves to document summarizing the progress, learnings, and decisions organized into three key sections:

1. **Part 1: DTP Phase I Briefings and Shared Foundations.** This section summarizes the activities and findings to date of the DTP FAWG, which is focused on strategies to reduce emissions from the most carbon-intensive periods of electricity demand.
2. **Part 2: ISO-NE Future Needs Assessment.** Peaker plants play a key role in supporting resource adequacy. Having a strong foundation on the evolving resource adequacy needs of the electric grid is important to informing future work of the DTP FAWG (i.e., Phase II and III). This section, therefore, details available modeling on the expected evolving resource adequacy needs in ISO-NE and related implications.
3. **Part 3: Recommendations and Next Steps for Future FAWG Activities.** As the DTP FAWG moves deeper into Phases II and III of their work, it will be important to maintain alignment and build on the detailed findings from Phase I, in order to deliver clear recommendations to the ETAB. This section discusses additional work and activities that may help the DTP FAWG – and other FAWGs -- achieve its goal.

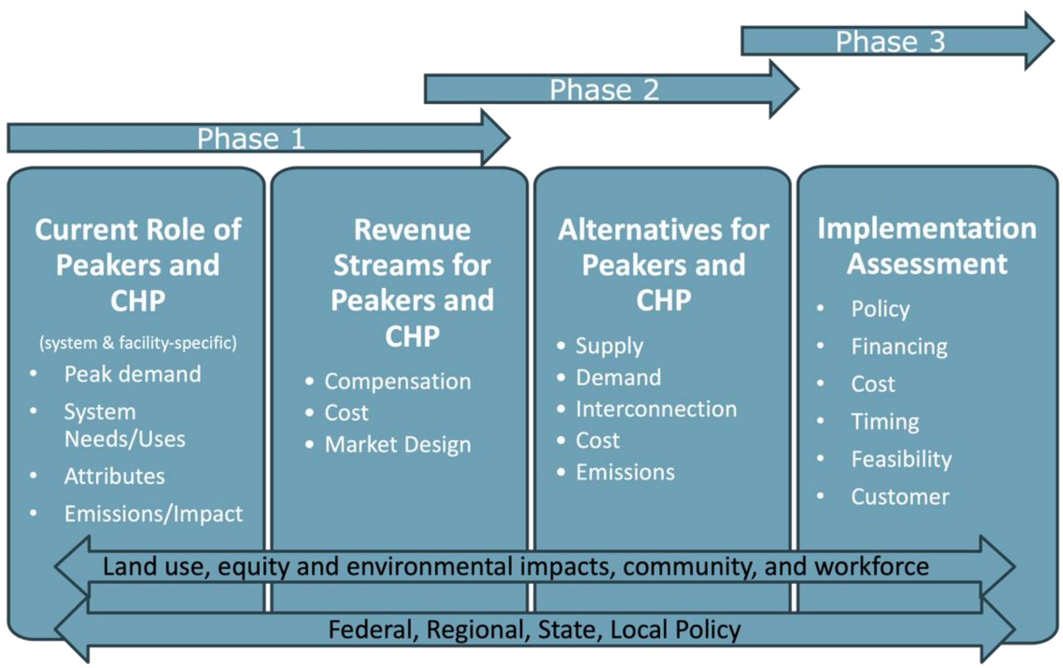
Part 1: Phase I Briefings and Shared Foundations

Organization of the DTP Workstream

Similar to the other FAWGs, the DTP FAWG is structured around a three-phase workplan, which began in 2024 and is scheduled to proceed over the course of 2025.

- **Phase I** commenced with an ETAB meeting in September 2024, followed by a DTP FAWG meeting in October 2024. Early activities focused on establishing a common understanding of current conditions and system needs. This included a regional and statewide overview of peak demand, compensation structures, market dynamics, emissions, and existing policies. The group also conducted a facility-level analysis of four specific plants, examining their characteristics, costs, community context, and applicable incentives.
- **Phase II**, which began in Spring 2025, is evaluating supply- and demand-side alternatives to these resources, including interconnection, cost, and emissions considerations.
- **Phase III** is targeted to commence in late Fall of 2025 or early Winter of 2026. In this phase, the DTP FAWG will assess policy, financing, and implementation pathways, with the goal of delivering clear recommendations to the ETAB on specific ways to affordably reduce peak power emissions while maintaining system reliability. System-level resource interactions and cross-cutting local issues, such as land use, equity, workforce, and permitting, are expected to be incorporated throughout.

Figure 2. Example Workstream Overview of DTP FAWG



In Phase I, E3 presented a series of briefings to the DTP FAWG to establish a shared foundation of technical knowledge. These presentations were designed to help participants engage with the relevant system dynamics, technologies, and policies that shape peak demand and peaker plant operations in Massachusetts. Materials covered the role of peaking and CHP resources in the regional power system, the timing and drivers of peak electricity demand, patterns of generator use, and related emissions, reliability, and cost considerations. E3 also provided Massachusetts-specific data to ground the group's understanding in local conditions and highlighted key considerations around market participation, facility siting, and policy development. This technical foundation was intended to enable informed discussion and support the development of Phase II alternatives and Phase III implementation and recommendations.

Role of Peaker Plants in New England

As part of Phase I, the DTP FAWG received and discussed an overview of peak electricity demand and the role of peaker plants in the New England electricity market. Peak demand refers to the interval of highest electricity usage within a given period and is shaped by the aggregate behavior of system users. While power consumption varies throughout the day and year, the highest demand tends to occur on the hottest or coldest days, typically in the late afternoon or evening. To serve this demand, the electric system relies on a combination of resources. Large, efficient baseload units provide steady generation, and smaller, flexible generators – peaker plants – are dispatched to meet demand spikes beyond the base load level.

Peaker plants are designed to operate during limited hours, generally when other more efficient resources are insufficient. These resources are characterized by their dispatchability (i.e., to come on- and off-line quickly, as needed/called on), rapid ramping ability, and current reliance on fossil fuels; frequently, peaker plants are located on small physical footprints closer to load centers (i.e., where customer demand is greatest). Capacity factor is a measure of how much output a resource provides relative to its total potential output if it were operating 24/7. In its review, the DTP FAWG further defined peaker plants as having a capacity factor of less than 15%, as reported by the U.S. Energy Information Administration (EIA) for 2022. E3 highlighted that while these facilities operate infrequently, they play a key role in maintaining system reliability during peak periods or constrained system conditions. Illustrative scenarios showed how peaker plants are brought online as demand increases throughout the day, or as solar generation wanes in the evening. They can also serve as key sources of backup supply when electric transmission systems are constrained (i.e., unable to deliver enough power to meet demand in a given area), other generators are offline, or variable renewable output is low (e.g., power production at a solar or wind facility is lower than needed/expected). Some facilities also have dual fuel capabilities and on-site fuel oil storage, which makes them a valuable and reliable source of power if natural gas fuel supplies are constrained and/or interrupted during the winter. Currently, Massachusetts is considered a summer-peaking system, but electrification of building heat and transportation is expected to shift peak demand toward winter in future years. This transition, combined with increased cold-weather fuel constraints and outage risks, may further increase reliance on peakers during winter months.

In a regional context, the FAWG reviewed data showing that there are nearly 200 fossil fuel generators in New England, with approximately half falling under the capacity factor threshold for a peaker plant; of these, Massachusetts is home to roughly half (i.e. peakers in Massachusetts represent about 25% of total fossil fuel capacity in New England). Many of these plants are strategically positioned to provide specific locational value, such as either near population centers or in constrained areas on the transmission system. Table 1 identifies the peaker plant facilities that are being considered in the DTP assessment; it includes EIA data from 2022 adjusted to account for known market additions (e.g., Northeast Reliability Center in Peabody), conversions (e.g., Cogentrix Plant in West Springfield), and retirements (e.g., Mystic Station in Everett).

Figure 3. MA Peaker Share of ISO-NE Capacity (2022)

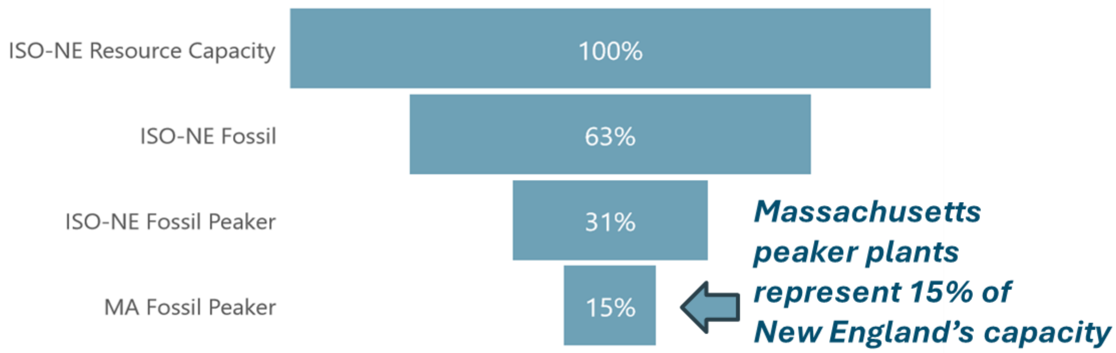
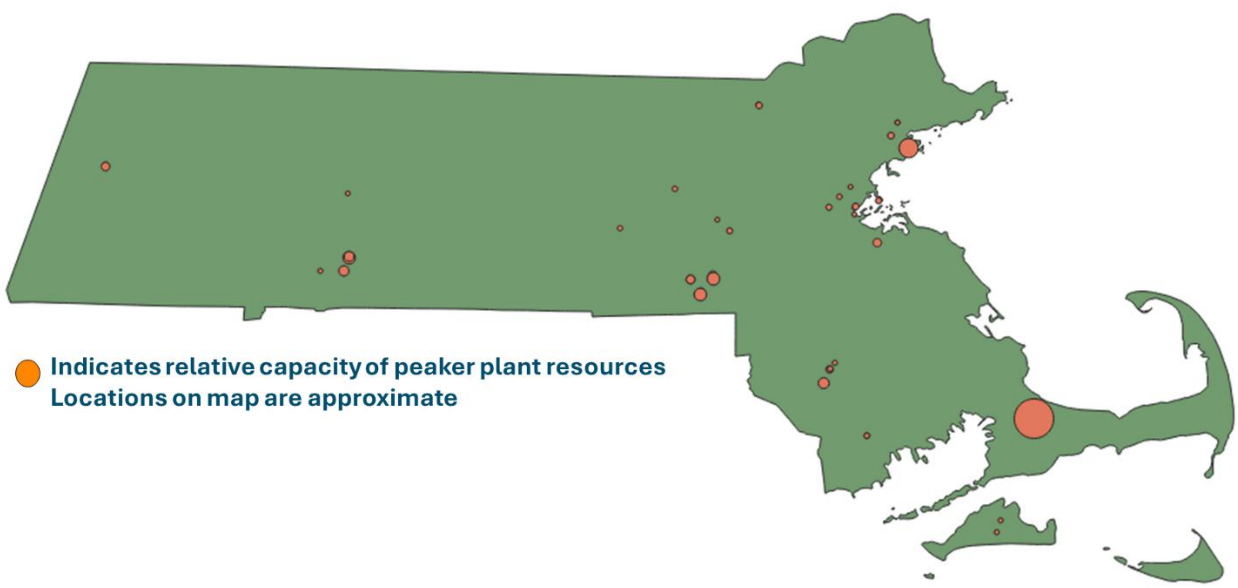


Table 1. Massachusetts Fossil Fuel Peaker Plants with Capacity Factor <15%

Plant Name	City/Town	Capacity (MW)	Primary Fuel Type
Canal Station	Sandwich	1495	Gas
Salem Harbor Station	Salem	798.2	Gas
Stony Brook Energy Center	Ludlow	541.5	Gas
Exelon West Medway II	Medway	263.6	Gas
Masspower	Springfield	260.9	Gas
Milford Power, LLC	Milford	249.3	Gas
Potter (Potter II/Watson Station)	Braintree	217	Gas
Dighton	Dighton	200	Gas
Pittsfield Generating	Pittsfield	175.5	Gas
Medway Station	Medway	135	Oil
Cleary Flood	Fall River	121	Gas
Dartmouth Power	Dartmouth	97.4	Gas
Tanner Street Generation, LLC	Lowell	85	Gas

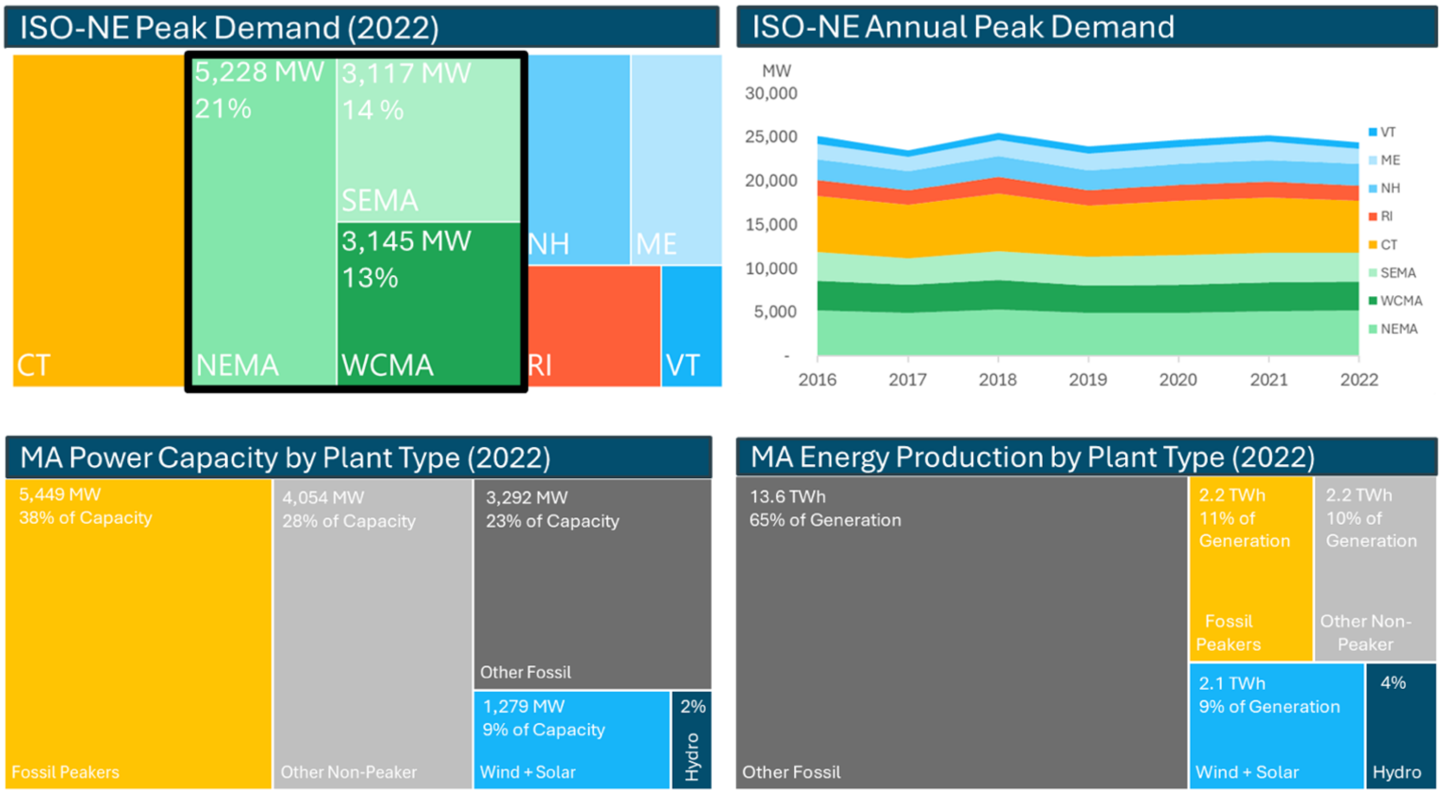
MBTA South Boston Power Facility	Boston	69	Oil
Waters River	Peabody	64.9	Gas
Northeast Reliability Center	Peabody	60	Gas
Framingham Station	Framingham	42.6	Oil
Cherry Street	Marlborough	17.3	Gas
Shrewsbury	Shrewsbury	14	Oil
West Water Street	Taunton	10	Oil
Front Street	Chicopee	8.1	Oil
Oak Bluffs Diesel Generating Facility	Oak Bluffs	8.1	Oil
West Tisbury Generating Facility	West Tisbury	5.4	Oil
Wilkins Station	Marblehead	5.4	Oil
Centech Gas Generator	Worcester	2.5	Gas

Figure 4. Relative Size and Location of Peaker Plants in Massachusetts



The DTP FAWG also discussed regional load and capacity data to help contextualize Massachusetts' role within the New England system. In 2022, Massachusetts accounted for 47% of ISO-NE's peak demand, which has remained relatively stable around 25,000 MW over the past seven years. Additionally, Massachusetts is the only New England state with individual load zones, reflecting its higher demand density and transmission constraints. Peaker plants in Massachusetts represent 15% of the region's total resource capacity.

Figure 5. Nearly Half of Regional Peak Demand is from Massachusetts



In its review, the DTP FAWG contextualized the use of fossil fuel peaking resources, noting how their emissions have changed over time. Total power sector emissions have declined, largely due to the retirement of coal plants and the increasing share of renewables and natural gas. However, as more fossil baseload generation is replaced with renewables, gross contributions from peakers may increase during scarcity events, potentially raising both carbon and local air pollution during peak periods. These emissions challenges were presented alongside the evolving resource landscape in Massachusetts, including the retirement of large plants like Mystic, Pilgrim Nuclear, and Salem Harbor Power Stations, and the recent commissioning of new peaking resources like the Peabody-based Northeast Reliability Center.

The Role of Combined Heat and Power (CHP) Plants in Massachusetts

In addition to reviewing the role of peaker plants, the DTP FAWG also explored the role of combined heat and power (CHP) facilities in Massachusetts as part of Phase I, including an overview of how CHPs, also known as cogeneration (co-gen) facilities, operate and contribute to the electric system. CHP plants are fossil fuel–fired resources that contribute meaningfully to regional capacity with distinct applications. In contrast to peaker plants, which are often compact in design, relatively inexpensive to build, and valued for their ability to ramp quickly, CHP facilities are typically designed for continuous operation, often at or near baseload. These systems pair a conventional, combustion generator with a waste heat recovery system to produce both electricity and thermal energy from a single input. Thermal energy is often used for district heating of campuses, like universities and hospitals, or for industries with processes that require high-temperature heat. While CHP facilities may increase their power output to support peak demand, their primary value lies in serving steady, predictable loads.

The DTP FAWG reviewed materials from the US Department of Energy and the EIA indicating that Massachusetts has more than 200 registered CHP facilities, representing 1.6 GW of capacity and supplying roughly 10% of the state's electricity needs. Industrial CHP facilities tend to be larger, averaging greater than 20MW at each site, whereas there are four times as many non-industrial CHPs averaging less than 4MW at each site. While most CHP facilities use traditional fossil fuels, like oil and natural gas, there are several applications of landfill gas or biogas.

Building on this foundation, the FAWG discussed that the high system efficiency of CHP facilities in supporting both electric and thermal final end use demands make substitution challenging. It was noted, however, that as reliance on other fossil fuel-fired resources declines as part of the Commonwealth's efforts to decarbonize the broader generation mix, CHP facilities are expected to represent a larger proportion of remaining emissions.

Table 2. Size, Type, and Number of CHPs in Massachusetts

Sector	Sites	Capacity (MW)
Industrial	45	1058
Commercial, Institutional, & Other	182	627

Source: The State of CHP: Massachusetts, Department of Energy Office of Energy Efficiency and Renewable Energy, 2017, https://betterbuildingssolutioncenter.energy.gov/

Overview of Resource Adequacy

As part of the technical foundation in Phase I, E3 introduced the concept of resource adequacy, which is the ability of the power system to reliably meet electricity demand under a range of conditions. Resource adequacy planning focuses on ensuring that there is sufficient supply available to meet demand during challenging conditions, including during periods of high demand, unexpected outages, and/or limited renewable production. Electricity systems, including ISO-NE, are typically planned to meet a "one-day-in-ten-year" reliability standard, meaning loss of load should occur, on average, no more than once every ten years. While resource adequacy is one important aspect of grid reliability, it is distinct from other operational standards such as transmission security and operating reserve requirements.

To help the FAWG evaluate different types of resources through a reliability lens, E3 presented the concept of effective load carrying capability (ELCC). ELCC measures a resource's contribution to system reliability relative to "perfect" capacity (that is, generation that is always available). E3 illustrated how ELCC varies by technology, and how certain resources, such as wind, solar, and 4-hour energy storage, exhibit declining marginal contributions to the electric system as their penetration increases.

Part 2 of this report provides a deep dive on foundational resource adequacy topics and the evolving needs of the New England electricity system. In particular, the resource adequacy discussion in Part 2 reinforces and builds on a key discussion point from the FAWG meetings: the importance of evaluating how individual resources and portfolios of resources operate during the most challenging system conditions. While annual generation from fossil fuel-fired power plants is projected to decline as additional zero-emissions resources like wind and solar are added to the grid, studies, including those by ISO-NE, have found that the amount of firm capacity required during the most critical reliability periods may be similar or even exceed today's levels.

Overview of New England Electricity Markets

Building on the resource adequacy discussion, the DTP FAWG presented an overview of New England's electricity markets, with a focus on how peaker plants are compensated. The briefing began with a high-level look at the distinct revenue streams available to generators. Peaker plants earn most of their revenue from two sources: energy market payments and forward capacity market payments. The energy market provides variable revenues tied to real-time production and market prices, while the forward capacity market offers fixed revenues to resources that commit to being available to serve load when called upon in the future. As described below, capacity market revenues are often a key source of compensation to allow peaker plants to recover their ongoing operational costs, given their low annual utilization and limited participation in the energy market.

The FAWG examined how capacity markets address the "missing money" problem, in which – in part due to price caps in the energy market to limit consumers' exposure to volatility – energy market revenues alone are insufficient to recover the fixed costs of certain generators, particularly higher marginal cost peaker units that run infrequently. Without this supplemental revenue stream, many resources would not have enough incentive to remain in the market. In ISO-NE, capacity is procured via a forward capacity auction, in which pricing is influenced by both regional demand forecasts and resource-specific factors such as effective load carrying capability (ELCC). ISO-NE is transitioning from a forward, annual model, where capacity is procured three-years in advance, to a prompt, seasonal capacity market in future years, which will more accurately reflect changing demand and available resources. For peakers, these market revenues are often the primary source of compensation, and their participation is shaped by auction outcomes, retirements, and the capacity accreditation process.

DTP workshop materials also highlighted how energy market price signals vary by location, introducing the concept of locational marginal pricing (LMP) as a mechanism for reflecting the marginal cost of serving load in a specific area of the grid. When congestion occurs, LMPs can rise significantly in constrained areas, sending stronger revenue signals to generators in those zones.

This is especially relevant in Massachusetts, which has historically been considered an import-constrained region. Transmission constraints can elevate both energy and capacity prices in such areas, enhancing the economic case for siting or retaining peakers locally. As an example, the FAWG assessed a transmission event in July 2023 that led to a 30-minute supply constraint and a dramatic spike in wholesale electricity costs, illustrating how just a few hours can drive a large share of annual electric system costs.

Further, as a region with limited access to natural gas pipeline infrastructure, New England is susceptible to curtailment of natural gas for power production during cold weather, when it is reserved for home heating needs. Liquid natural gas (LNG) is an important consideration in this winter reliability assessment, as LNG can be delivered and stored, including in the EMT facility outside of the Boston load center (this specific topic is being addressed by the EMT FAWG).

Finally, the DTP FAWG discussed a range of demand- and supply-side strategies that could support a reliable, decarbonized system under deep electrification. On the demand side, energy efficiency, managed electrification, and demand response were presented as important and impactful tools for reducing the peak electric demand impacts of building and transportation electrification. Specific measures such as building shell improvements and adoption of more efficient heating technologies (like ground source heat pumps) can help mitigate winter peak challenges. Likewise, flexible charging incentives for electric vehicles (EVs) were noted as a strategy to flatten load profiles and reduce stress on the grid during high-demand periods.

On the infrastructure side, DTP workshops highlighted the role of transmission system upgrades and grid-enhancing technologies to alleviate local reliability constraints, especially in areas with limited import capacity. In terms of supply, it was understood that renewables and battery storage will continue to provide contributions to system reliability as their share of the capacity mix grows over time, their marginal value declines, however, at higher penetrations. Increasing the duration of storage – from current 4- to 8-hour lithium-ion systems to emerging long-duration technology – was identified as a pathway to boost reliability contributions of storage resources. The FAWG was also introduced to new and emerging zero-carbon technologies that could support system needs for firm capacity, including small modular nuclear reactors, linear generators, and hydrogen fuel cells. Finally, consultant briefings noted that existing and new combustion facilities may continue to play a role, particularly if they can be transitioned to operate on lower carbon fuels, to help meet peak system needs and continue to advance decarbonization goals (Figure 20).

Review of Relevant Policies

Consulting teams from GCC and Harvard EELP opened this segment of the Phase I briefing by describing the layered policy environment that governs electricity sector planning and operations. At the federal level, emissions limits, tax incentives, and regulatory guidance all affect investment and operational choices. The presentation noted that these policy influences span national, regional, state, and local jurisdictions. Agencies such as the Federal Energy Regulatory Commission (FERC) and Environmental Protection Agency (EPA), ISO-NE planning frameworks, state-level mandates, and local priorities all shape decisions about resource siting and operations.

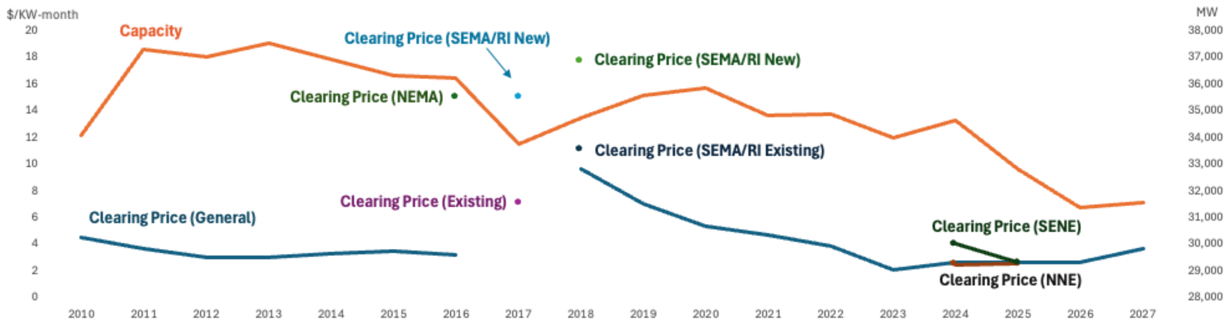
At the national level, several recent and pending federal actions may affect how peaker plants operate in the future. The presentation summarized orders from FERC including Order 745, which establishes compensation for demand response, and Order 845, which creates provisions for surplus interconnection capacity. GCC and EELP also highlighted FERC Order 2222, which supports distributed energy resource participation in ISO-NE markets. The Inflation Reduction Act (IRA), passed in 2022, includes a 30% investment tax credit (ITC) for eligible clean energy technologies such as wind, solar, and storage, and a production tax credit (PTC) of up to $0.0275 per kWh for qualifying renewable generation. It was presented as a major influence for its potential to accelerate renewable and storage deployment, especially where renewable curtailment is likely. If curtailment occurs, storage can absorb excess generation and reduce emissions during peak periods. The *One Big Beautiful Bill Act of 2025*, signed by the Trump administration in July 2025, curtails and eliminates these tax credits for new generation after 2027. Lastly, it was noted that the 2024 EPA standards for fossil fuel-fired power plants will affect plant design and fuel choices, especially for units that operate during winter peaks; however, the EPA is in the process of rescinding these regulations.

Table 3. National Policies Influencing Decarbonization of Peak Demand

Policy/Program	Description
FERC Order 745	Enables demand response to be compensated at locational marginal price (LMP)
FERC Order 845	Establishes provisions for surplus interconnection capacity, potentially useful for peaker replacements
FERC Order 2222	Supports integration of distributed energy resources into ISO-NE markets
Inflation Reduction Act (IRA)	Provided tax credits for storage, renewable generation, and thermal resources. The *One Big Beautiful Bill Act of 2025*, signed in July 2025, curtails and eliminates these tax credits for new generation after 2027.
EPA Fossil Fuel Standards	Proposes emissions caps and fuel requirements for new and existing fossil plants. (In process of being rescinded)

E3 then turned to regional ISO-NE market rules that influence peaker plant operations, explaining how these design elements intersect with broader policy considerations and planning processes. The Forward Capacity Market (FCM) allows market participants to forecast, build, and transact on future capacity needs. Needs are forecasted and capacity is procured three years in advance through competitive auctions. E3 explained that capacity prices vary by zone and can send entry or exit signals based on market conditions. When more capacity enters the market, prices fall, which may prompt retirement of older peaker units. When supply tightens, prices rise, encouraging new investment. E3 also introduced ISO-NE market rules that govern plant participation, including the de-list process and Reliability Agreements that can keep peakers online when needed for system reliability. In addition, the "pay for performance" framework was presented, which imposes penalties and rewards based on how much energy a resource actually delivers during five-minute scarcity intervals. This structure favors fast-responding technologies like batteries or combustion turbines over slower, non-spinning reserves.

Figure 6. ISO-NE Forward Capacity Auction Clearing Prices Can Influence Peak Resource Decisions



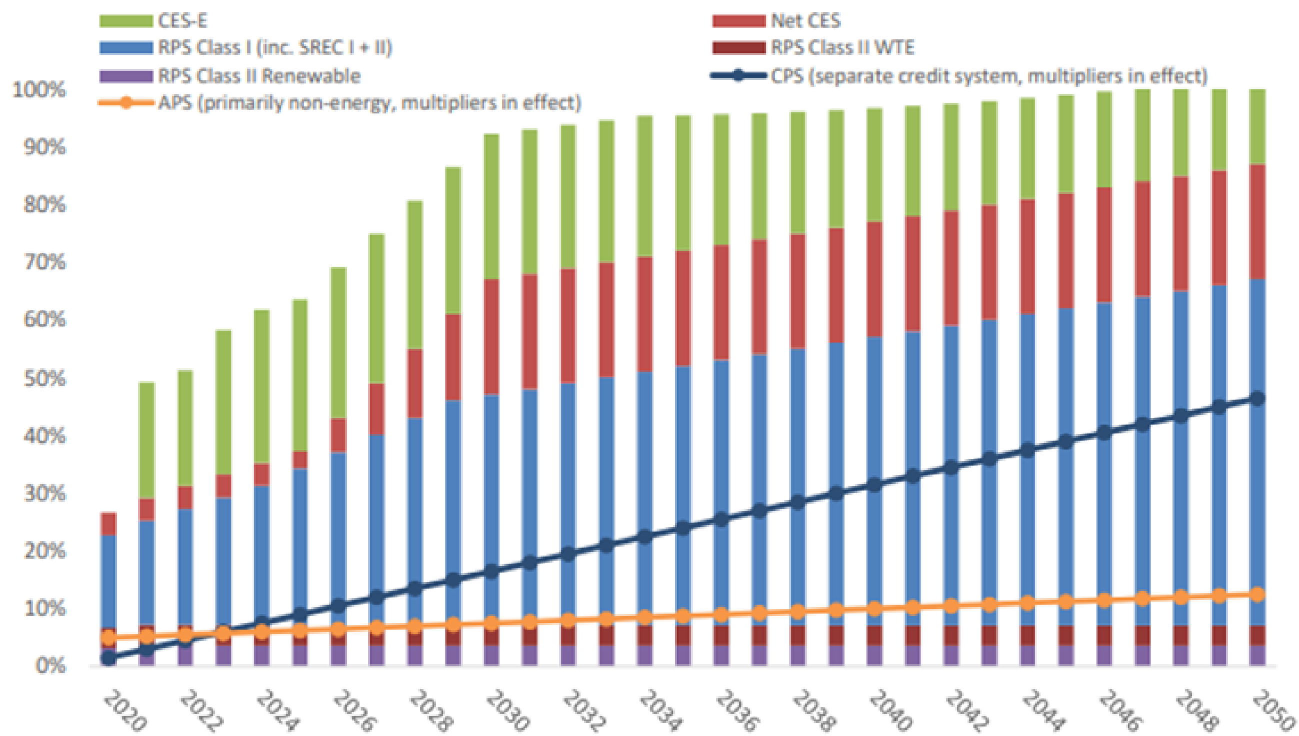
Members of the OET consulting team from GCC and EELP outlined ways in which Massachusetts has implemented policies that influence the cost, operation, and emissions profile of peak resources. Included in the presentation to the DTP FAWG were summaries of state policies noted in Table 4 below.

Table 4. Massachusetts Policies Influencing Decarbonization of Peak Demand

Policy/Program	Description
2015 Energy Storage Initiative	Established statewide target of 1,000 MWh of battery storage
2017 Clean Energy Standard (CES)	Reduces carbon-intensity of retail electricity supply
2020 Clean Peak Energy Standard (CPS)	Creates clean peak obligation and incentives for qualifying resources
2021 Climate Roadmap Act	Codifies environmental justice as a factor in resource siting
2022 Clean Energy and Offshore Wind Act	Requires IOUs to offer time-of-use rates
Ongoing Legislative Priorities	Focus areas include interconnection acceleration and siting reform

These standards set progressively stricter requirements for the share of electricity that must come from clean resources. The CES distinguishes between new and existing clean generation and requires retailers to procure a rising share of electricity from qualifying resources or pay an alternative compliance fee. As this policy drives more solar generation onto the system, peak demand shifts later in the day, increasing the need for storage to meet evening load without relying on fossil generation.

Figure 7. Combined Massachusetts Standards as a Percentage of Retail Sales



Source: Clean Energy Standard: Frequently Asked Questions, Massachusetts Department of Environmental Protection, 2024, https://www.mass.gov/doc/frequently-asked-questions-massdep-clean-energy-standard

The CPS, established by DOER in 2020, requires that a portion of retail sales come from clean peak resources. Electric retailers must demonstrate compliance by procuring qualified resources or making alternative compliance payments. Energy storage plays a central role in meeting these targets as well. The state has set a storage deployment goal for 2025; a large portion of the needed capacity is already in place through existing pumped hydro and recent battery builds, while additional capacity is moving through the ISO-NE interconnection queue.

The working group also noted the impacts of more recent legislation, including the 2021 Climate Roadmap Law, which incorporated environmental justice into siting, and the 2022 Offshore Wind Law, which established time-of-use rate mandates. Ongoing legislative priorities were noted as well, including siting reform and interconnection improvements for renewables and storage.

With supporting context from consulting teams, including representatives from GCC and Harvard EELP, the DTP FAWG explored additional context on several state-level programs that support clean peak resource development and demand-side management. The ConnectedSolutions program, an active demand response program run by electric distribution companies as part of Mass Save, was highlighted as a key demand response tool. In 2024, it delivered approximately 200 MW of peak demand reduction across residential and commercial customers using a mix of smart thermostats, energy storage, and "bring-your-own-device" participation. The program primarily targets system cost avoidance during summer peaks and compensates participants through seasonal incentives or per-event payments depending on the offering.

GCC also reviewed the Alternative Energy Portfolio Standard (APS), which provides incentives for technologies that reduce fossil fuel use, such as CHP, heat pumps, fuel cells, and biofuels. Like the RPS, eligible technologies receive Alternative Energy Certificates (AECs) based on their output. In 2023, APS technologies generated 2.8 million MWh, with CHP representing the largest share of capacity among participating technologies.

Participating Facilities

From its inception, the DTP FAWG included members from three Massachusetts peaker facilities and one CHP facility. The participation of these generators in the FAWG's discussions provided perspectives into the specific challenges and opportunities that are unique to individual sites. This analysis provided useful contrast to the system-wide approach that otherwise examined facility value and substitution potential at a system-level.

Cogentrix's facility in West Springfield is a retired conventional peak generator. With a historical capacity of 229 MW and an average capacity factor of about 5%, the site was powered by natural gas, distillate fuel oil, residual oil, and kerosene. It is currently being converted to host a 45 MW battery storage system.

Hull Street Partners' facility in Pittsfield is an active peaker with a capacity of 181 MW situated on about 6 acres of leased land. It uses natural gas and distillate fuel oil to deliver reliability to the Western/Central Massachusetts load zone. The plant reflects typical peaker attributes, including limited site footprint, dual-fuel capability, and a capacity factor of approximately 5%. For its December meeting, the DTP FAWG toured the Pittsfield plant to better understand its site-specific characteristics and limitations.

The **Canal Station facility, owned by JERA Americas** – which has committed to reaching net-zero emissions by 2050 in alignment with state law – is an active fossil-fueled power plant located in Sandwich, Massachusetts. It has a total capacity of 1,578 MW and is interconnected via a 345 kV transmission line. The facility includes three units: two older steam turbine units (Canal 1 and 2) totaling 1,125 MW and commissioned in 1968 and 1978, and one more recent, quick-starting unit (Canal 3) with a capacity of 333 MW that came online in 2019. The plant uses residual fuel oil and natural gas, operating at an average capacity factor of less than 5%, to deliver power to the Southeast Massachusetts load zone, including geographically constrained Cape Cod. The site supports 50 full-time employees and contributes $3.5 million annually in local taxes.

With approximately 130 acres of land and significant interconnection rights, the site has potential for redevelopment. Its location – coastal, proximate to the Boston load pocket, and with existing transmission access – was identified as a key asset. Future strategies for the site include repurposing the facility for battery energy storage, switching to renewable fuels like biodiesel, and/or leveraging interconnection capacity to support offshore wind integration. Surplus interconnection service (SIS) was identified as a site-specific attribute of significant interest and critical to enabling the transition to new resources, such as offshore wind, solar, and battery storage.

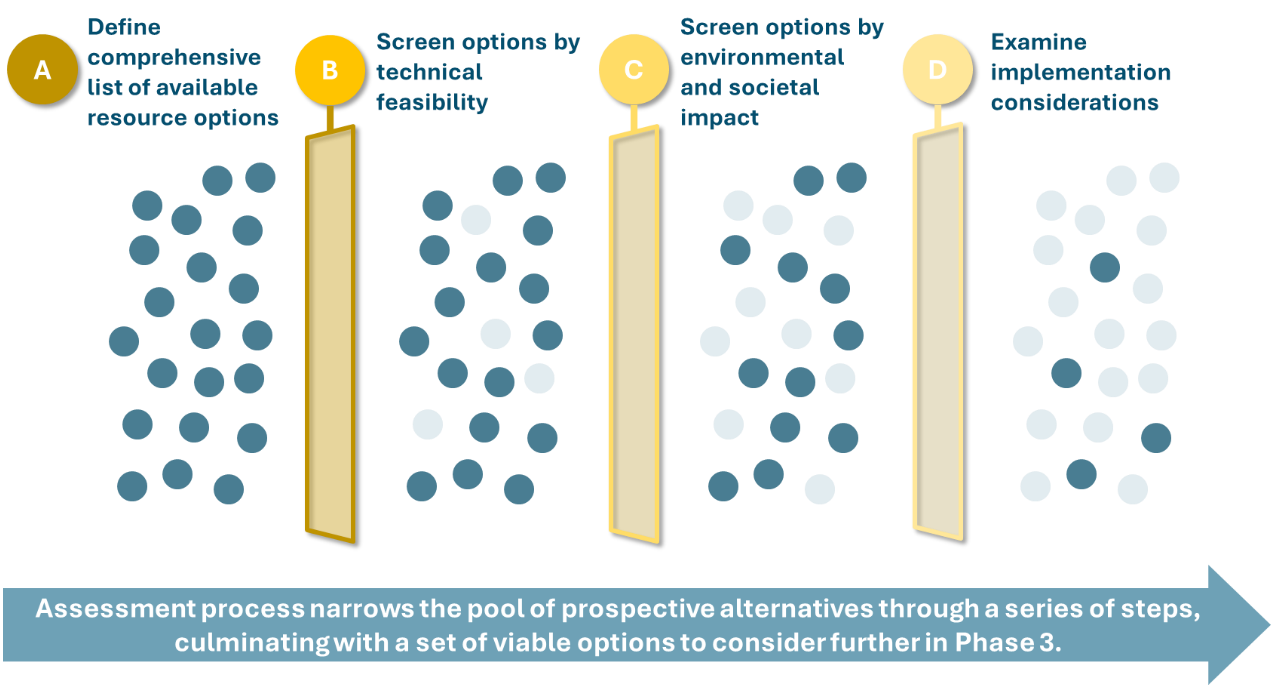
Tufts University's Central Energy Plant is an active CHP facility located in Medford, Massachusetts. The plant has a capacity of 4 MW, runs on natural gas, and is interconnected to the Northeast Massachusetts load zone with limited transmission access. The facility operates with high efficiency (approximately 75% when considering both heat and electricity) and maintains an average capacity factor over 70%.

Several constraints limit the options for transitioning the facility. The campus' urban location and distribution system limitations pose challenges for electrification. In the near term, Tufts is evaluating the potential to add ground-source heat pumps and battery storage. Long-term decisions will depend on future policy, regulatory incentives, and emerging technologies. On-campus generation continues to offer resiliency and economic benefits, particularly in a setting where other alternatives may not offer comparable reliability or efficiency.

Development of a Screening Assessment Framework

Phase I culminated with the development of a screening assessment framework in which various technologies and policies could be assessed at a high level against various criteria. Through several workshops, the DTP FAWG discussed the purpose, format, and contents of the framework. The overall goal of the framework is to first, develop a comprehensive list of potential technologies or resource options to reduce reliance on peaker facilities, then establish key criteria to screen out technologies that may not be feasible alternatives. The prevailing solutions can then be studied in more detail and, possibly, become part of final recommendations. The concept of this progressive screening framework is illustrated in Figure 8.

Figure 8. Illustrative Screening Framework Concept



Noting the importance of understanding system-level impacts, while also accounting for site-specific constraints, OET's consulting team, including CBI, E3, GCC, and Harvard EELP, identified and shared an initial list of technology and policy alternatives based on FAWG member input from previous meetings. Through several meetings, members of the FAWG provided additional feedback and aligned alternatives for further assessment. The DTP FAWG agreed that technology options should be very specific and that additional work to refine some policy options may need to occur in smaller work groups as the process advanced into Phase II.

E3, GCC, and Harvard EELP developed a proposed framework to assess each technology and policy alternative against a set of criteria, based on FAWG input and feedback, which were bucketed into the following categories:

Table 5. Assessment Framework Criteria

Technology	Policy
• Environmental Impacts • Feasibility • Community and Economic Impacts • Suitability for Fossil Fuel-Fired Peaker Replacement • Cost • Availability/Stage of Commercialization • Other Considerations (e.g., consistency with existing state policy, legal risks, federal policy risk)	• Impact on peak demand • Equity • Customer Cost Impacts • Impact on increasing availability of decarbonized supplies • System Cost Impacts • Implementation Needs/Risks • Timing • State Authority

With support from the consulting teams, DTP FAWG members assembled a comprehensive list of alternatives for assessment. Although there may be differing opinions among members of the working group regarding the efficacy of specific candidate solutions, there was a consensus to not prematurely exclude any options. Technology options focused on both demand and supply-side alternatives that could be scaled with application across a variety of sites.

The framework considers both quantitative and qualitative assessment criteria to evaluate a wide array of impacts for potential technology and policy solutions. In the continued spirit of facilitating a stakeholder driven process, critical sections of the assessment criteria were referred to subgroups of the DTP FAWG for further development and consideration.

- A **demand-side technology subgroup** was tasked with developing a list of demand-side measures to include for assessment in the DTP framework and to provide recommendations on evaluation considerations for demand-side measures.
- A **technology costs subgroup** categorized technology options based on availability and confidence of cost projections (e.g., levelized fixed costs and levelized cost of energy), including consideration of anticipated cost risks external to core assessment (e.g., federal support). The subgroup was also asked to recommend options for additional portfolio-level cost analysis.

- An **emissions subgroup** considered screening level characterization of emissions impacts with the goal of recommending short-listed options for portfolio level analysis. This assessment included identification of expected potential portfolio impacts and associated upstream and downstream impacts.
- A **community impact subgroup** was dedicated to assessing quantitative and qualitative metrics of social impacts on host communities and their neighbors.
- A **ranking subgroup** was formed to help consider the approach that should be used in ranking technologies against one another (e.g., red, yellow, or green), including what a ranking means and how it can be objectively applied, to ensure consistency across all technologies.

All subgroups were self-organized with support from OET and included six-to-ten volunteers from the FAWG. Each was charged with developing recommendations for how to measure the criteria within each designated topic area.

In its June 2025 meeting, the DTP FAWG received debriefs from each subgroup, including their summary recommendations. Several of the topic areas were identified by OET as needing additional development where findings and recommendations were not fully developed.

Review of Third-Party References

In order to provide members with a comprehensive understanding of the challenges, opportunities, and considerations related to decarbonizing peak demand while maintaining system reliability, a number of references were reviewed. Relevant materials considered by the DTP FAWG included "Insights from Fossil Fuel Replacement Case Studies," which was prepared by Applied Economics Clinic on behalf of the Berkshire Environmental Action Team. Additionally, the DTP FAWG received a briefing from Synapse Energy Economics on discussions around peaker plants in New York.

Expert Series

To ensure that all members of the DTP FAWG have access to the necessary information related to a diverse array of technology and policy considerations, a series of presentations was arranged in which information could be shared with interested parties on select topics. Experts included representatives of organizations like the United States Department of Energy's Sandia National Laboratory and National Renewable Energy Laboratory, the Electric Power Research Institute (EPRI), and the Massachusetts Department of Energy Resources (DOER), along with academic institutions and technology developers and providers. Presentations in the series covered topics including renewable fuels, energy storage, and surplus interconnection, with more session planned on transmission, smart grid technologies, and demand response, among others. This series is ongoing and plans to cover more topics related to the issue of decarbonizing the peak.

Progress and Milestones

The DTP FAWG has gained a common understanding of current and future peak demand in the New England region, as well as how peaker plant and CHP facilities interact with the market. The FAWG continues to work toward understanding and developing an inventory of feasible decarbonization opportunities for the four participating facilities. Throughout this process, major milestones of the DTP initiative were marked by critical meetings in which decisions were affirmed, in some cases, by a formal vote of the ETAB.

Table 6. Summary of Meetings and Milestones

Date	Party	Topic
9/30/2025	ETAB	Inaugural Energy Transformation Board Meeting
10/8/2025	DTP FAWG	Informational webinar on relevant background
1/14/2025	DTP FAWG	• Toured Pittsfield peaker plant and reviewed facility-specific data on Pittsfield and West Springfield peaker facilities. • Reviewed ISO-NE facility requirements. • Considered third-party reporting from Applied Economics Clinic on cases of peaker plant conversion.
1/22/2025	ETAB	Second Quarterly Energy Transformation Board Meeting
2/25/2025	DTP FAWG	Reviewed: • Proposed workstreams for Phase II. • "Straw" alternatives and assessment framework for feedback and input. • Policy scenarios. • Deep-dive on select technologies.
3/18/2025	DTP FAWG	Reviewed: • Presentation from Clean Energy Group on AEC report. • Presentation from Synapse on peak decarbonization analysis and supply and demand resources that could replace peaker plants. • Further feedback on policy options and assessment criteria, including identifying where additional clarity is needed and suggestions for additional policies to consider.
3/27/2025	DTP FAWG	Finalized and affirmed assessment framework and alternatives list for sharing with ETAB for approval as a starting point for Phase II assessment.

4/3/2025	ETAB	Reviewed, amended, and approved DTP framework
6/17/2025	DTP FAWG	Expert-led presentation on renewable fuels
6/24/2025	DTP FAWG	Expert-led presentation on energy storage
6/26/2025	DTP FAWG	Expert-led presentation on surplus interconnection

Part 2: ISO-NE Future Needs Assessment

Ensuring a reliable electricity supply is vital for protecting the health, safety, and security of residents across the Commonwealth. This section of the report provides a deep dive on the resource adequacy needs of Massachusetts, today and in the future. It then discusses at a high level the current role that “firm” capacity—in other words, resources that can dispatch on demand to meet system needs—plays in ensuring resource adequacy. Given that grid operations and planning are conducted on a regional scale across New England, this section discusses resource adequacy at the broader ISO-NE level, while focusing on Massachusetts-specific impacts and considerations.

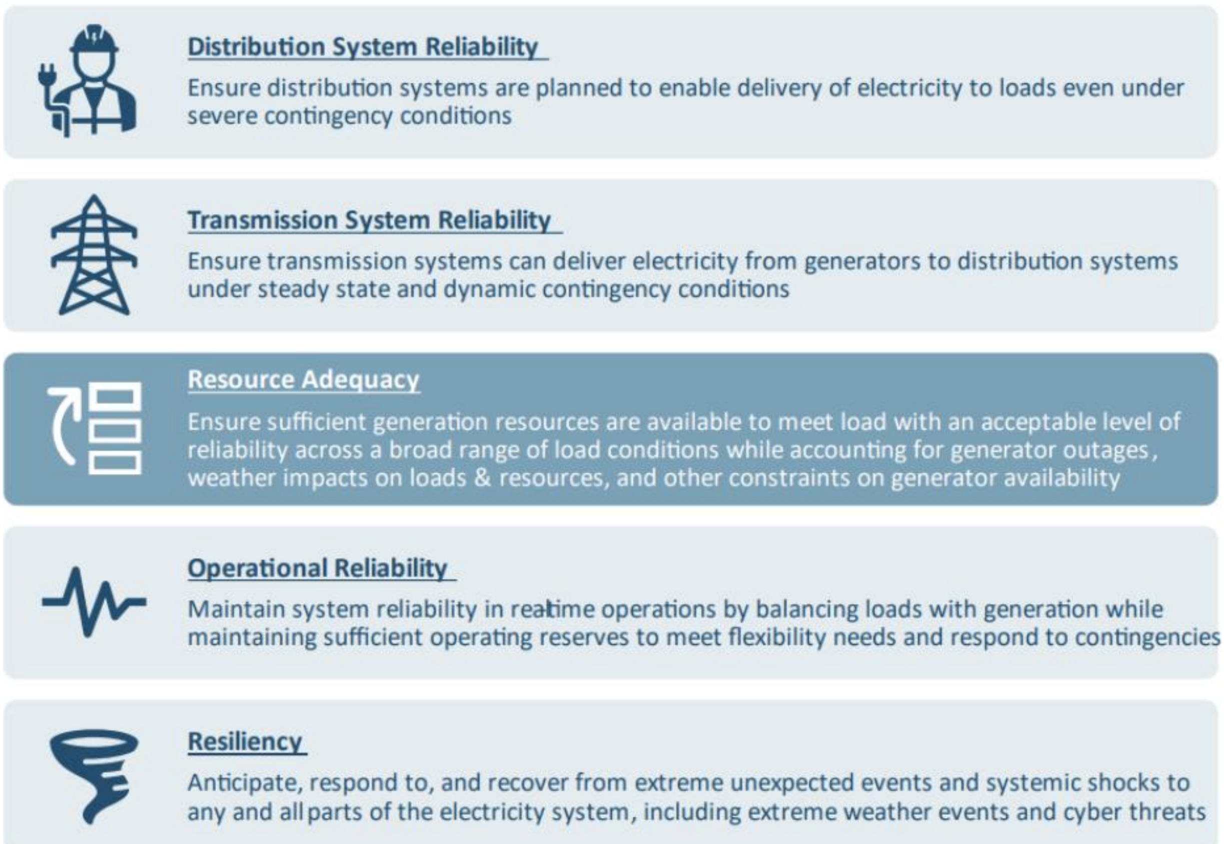
As noted in the introduction, the goal of Part 2 of this document is to expand on the resource adequacy foundation established during the first phase of the FAWG and summarized in Part 1, to further support the subsequent assessments of the Decarbonizing the Peak Working Group in Phases 2 and 3.

Electric System Reliability and the Role of Peaker Plants Today

Defining Reliability and Resource Adequacy

Ensuring reliable electricity service requires careful planning across all levels of the power system—from power plants to transmission lines to local distribution networks. These many aspects of reliability planning are illustrated in Figure 9. Central to this planning is **resource adequacy**, which refers to having enough available generation capacity to meet electricity demand at all times, particularly during periods of high usage or unexpected disruptions.

Figure 9. Major Elements of Reliability Planning

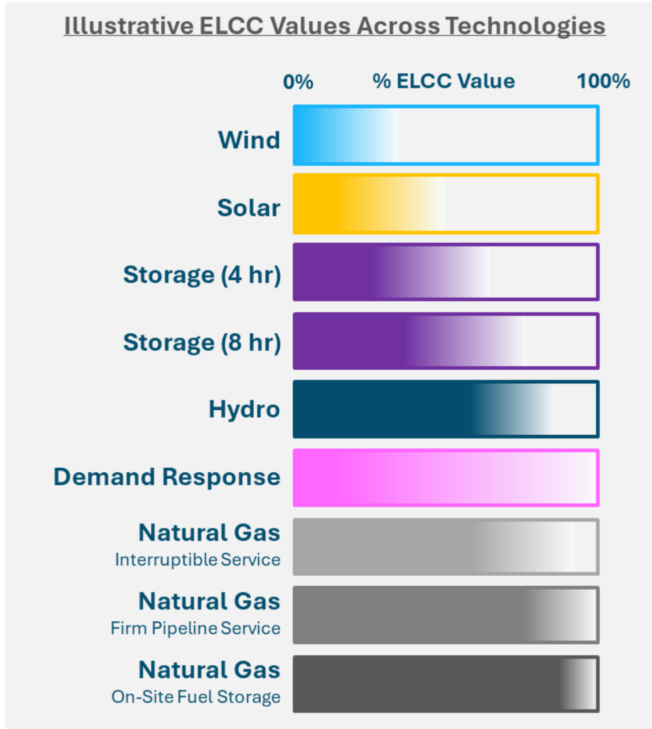


Resource adequacy is influenced by a range of factors, including the nature of electricity demand—such as its overall magnitude, seasonal trends, weather sensitivity, and daily usage patterns—as well as the attributes of supply resources, including their capacity, flexibility, likelihood of unplanned outages, and other constraints on availability. As such, it is expected that the resource adequacy needs and relative reliability risks of the system will evolve over time, particularly as the region pursues economy-wide decarbonization.

Measuring Resource Adequacy Contributions using Effective Load Carrying Capability

With the growing penetration of renewable energy and energy storage, along with changing patterns of energy demand driven by electrification, evaluating resource adequacy is becoming more complex. Traditionally, system planners often relied on basic rules of thumb to estimate the reliability contributions—or capacity value—of intermittent and energy-constrained resources. However, as these resources make up a larger share of the grid, such simplified approaches no longer capture the full picture. Higher renewable penetrations change when and how reliability risks occur, as explored further below. Additionally, the electrification of end uses in buildings, transportation, and industry is leading to changes in both the magnitude and timing of electricity demand, which leads to evolving system needs, in particular as winter demand grows.

To consistently evaluate how different resources support the grid during periods of higher risk for loss of load, we use **Effective Load Carrying Capability (ELCC)**. ELCC quantifies the capacity contribution of any electricity resource by expressing it in terms of equivalent "perfect capacity"—that is, a hypothetical resource that is always available when needed. This metric is now widely adopted across North America and increasingly used by utilities and regional transmission organizations (RTOs) for accrediting resources toward resource adequacy targets.



Conceptually, if a 100 MW resource has an ELCC of 50 MW, it means the system could rely on that resource to replace 50 MW of perfect capacity without any change in system reliability. ELCC is often expressed as a percentage by dividing the ELCC value by the resource's nameplate capacity—in this case, 50%. The ELCC value is determined using a **loss-of-load probability (LOLP)** model, which simulates grid performance thousands of times under varying demand and supply conditions to estimate the reliability contribution of each resource.

Figure 10 and Figure 11 below demonstrate how this works in practice.

Figure 10. Illustrative Demand Curve Demonstrating Diminishing Capacity Value of Solar With Increased Penetration

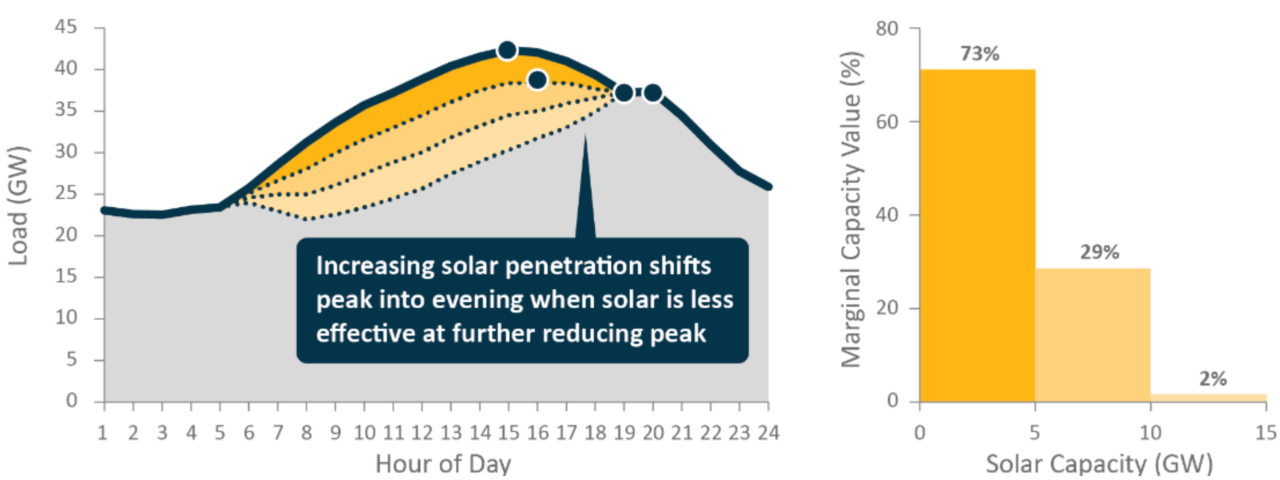
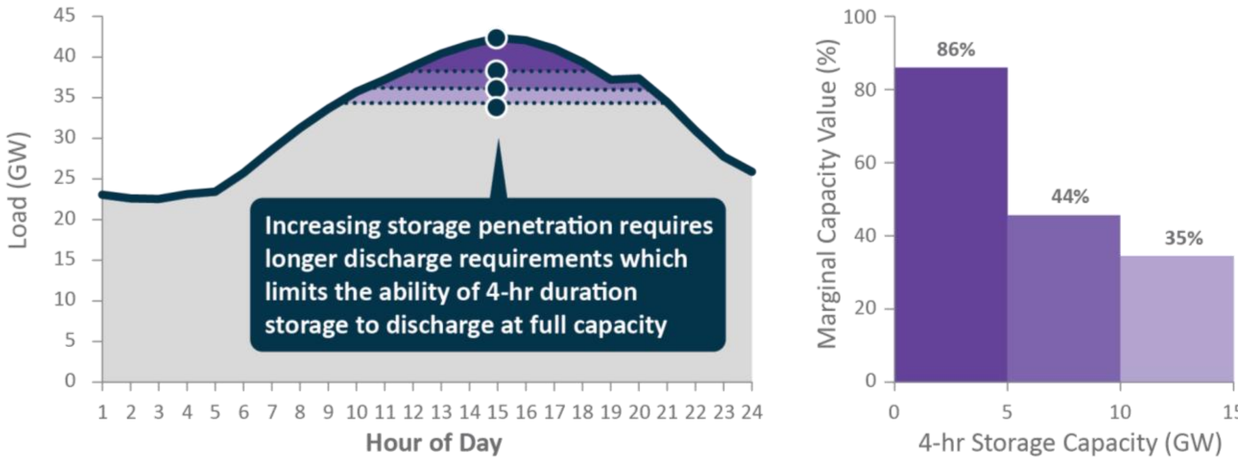
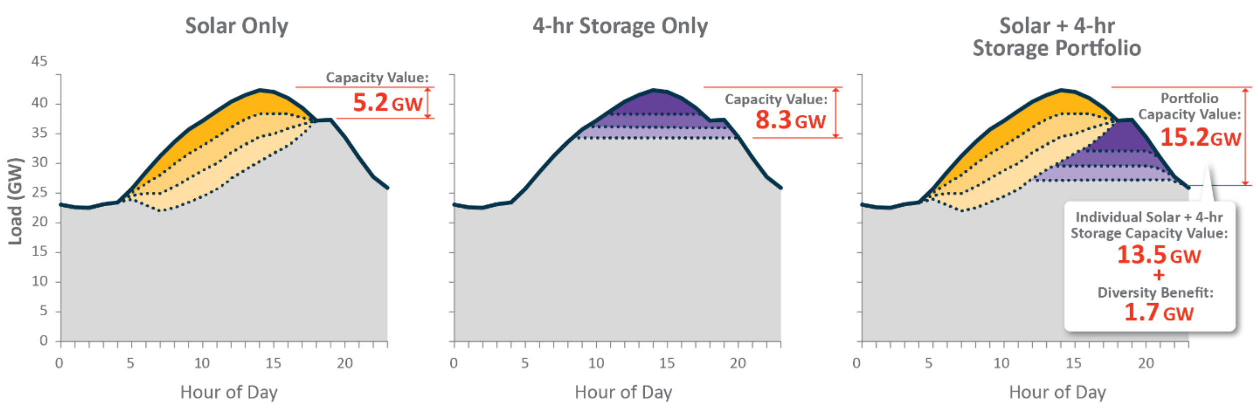


Figure 11. Illustrative Demand Curve Demonstrating Diminishing Capacity Value of 4-Hour Storage With Increased Penetration



Additionally, different resources in a portfolio can interact with each other in positive or negative ways. For example, solar and storage exhibit synergistic qualities that collectively provide more load carrying capability than the sum of the individual resources. In other words, together, these resources may be able to support the system over a broader range of resource and load conditions than they would individually. This diversity benefit is illustrated in Figure 12. Conversely, resources offering similar services or profiles, like "energy shifting" provided by storage and demand response, result in less incremental value gained.

Figure 12. Diversity Benefit of Synergistic Interactions Between Portfolio Resources



Today, peaker plants play a critical role in supporting New England's resource adequacy needs. However, as we evaluate pathways to reduce the state's reliance on fossil fuels, understanding the contributions that fossil fuel-fired peaker plants have provided to system reliability needs will be critical. As these pathways are evaluated, it will also be important to evaluate portfolio and load dependencies, such that future portfolios collectively meet the evolving reliability needs of the New England grid as the region decarbonizes.

One additional theme that will be important to consider is that a resource or group of resources ability to contribute to the region's capacity needs will depend on the rest of the resource portfolio.

Evolving New England Electric Grid

Electricity Demand Forecasts

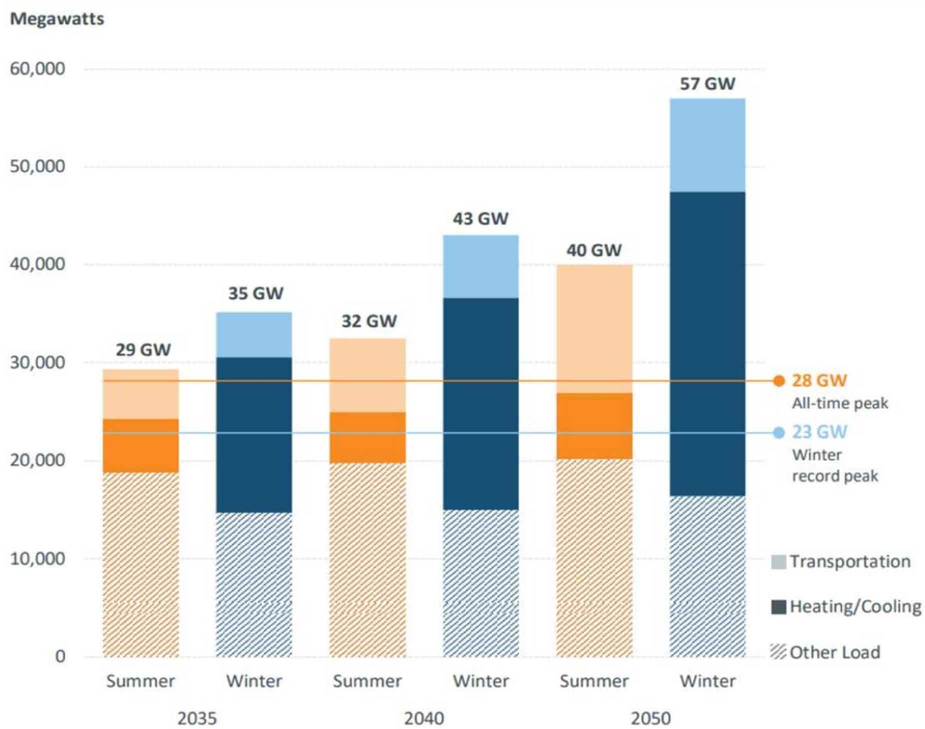
As the region pursues deep decarbonization, total energy demand and peak demand are expected to grow dramatically. Across a range of forecasts, electrification is expected to reshape the timing and magnitude of peak demand. For example, ISO-NE projects a shift from summer to winter peaks beginning in the mid-2030s, with systemwide demand expected to double by 2050. Massachusetts' CECP 2050 planning models demonstrate this same projected future pattern. Key trends driving this transition and embedded in both forecasts include:

- **Adoption of electric vehicles:** Models assume near-complete adoption of light and heavy-duty electric vehicles by mid-century (e.g., in CECP 2050, 19% of vehicles are electric by 2030 and 97% by 2050).
- **Building energy efficiency and electrification:** Scenarios assume building shell improvements and weatherization grow dramatically by mid-century, coupled with near-complete adoption of heat pumps in residential and commercial buildings (e.g., in CECP 2050, 47% of households are weatherized by mid-century and 92% of residential homes are electrified).
- **Industrial electrification:** Applicable low-temperature industry energy demands are electrified.

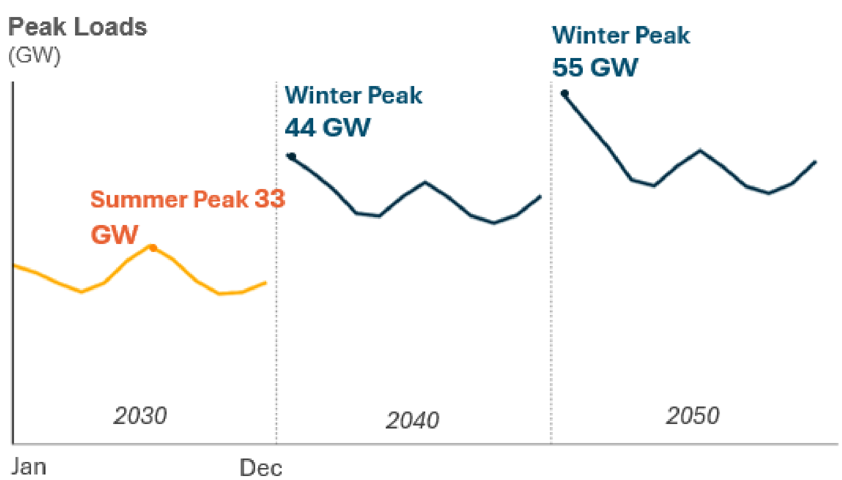
Across studies and forecasts, demand flexibility – i.e., the ability to shift load across time based on available generation and market prices – is expected. At the same time, the weather *variability* of demand will also increase as much of the region's building heating needs are electrified.

Figure 13. Peak Demand Projections by ISO-NE (top) and Massachusetts Clean Energy and Climate Plan (bottom), 2030-2050

ISO-New England 2050 Transmission Study



Massachusetts Clean Energy and Climate Plan 2050, Phased Scenario Peak Loads

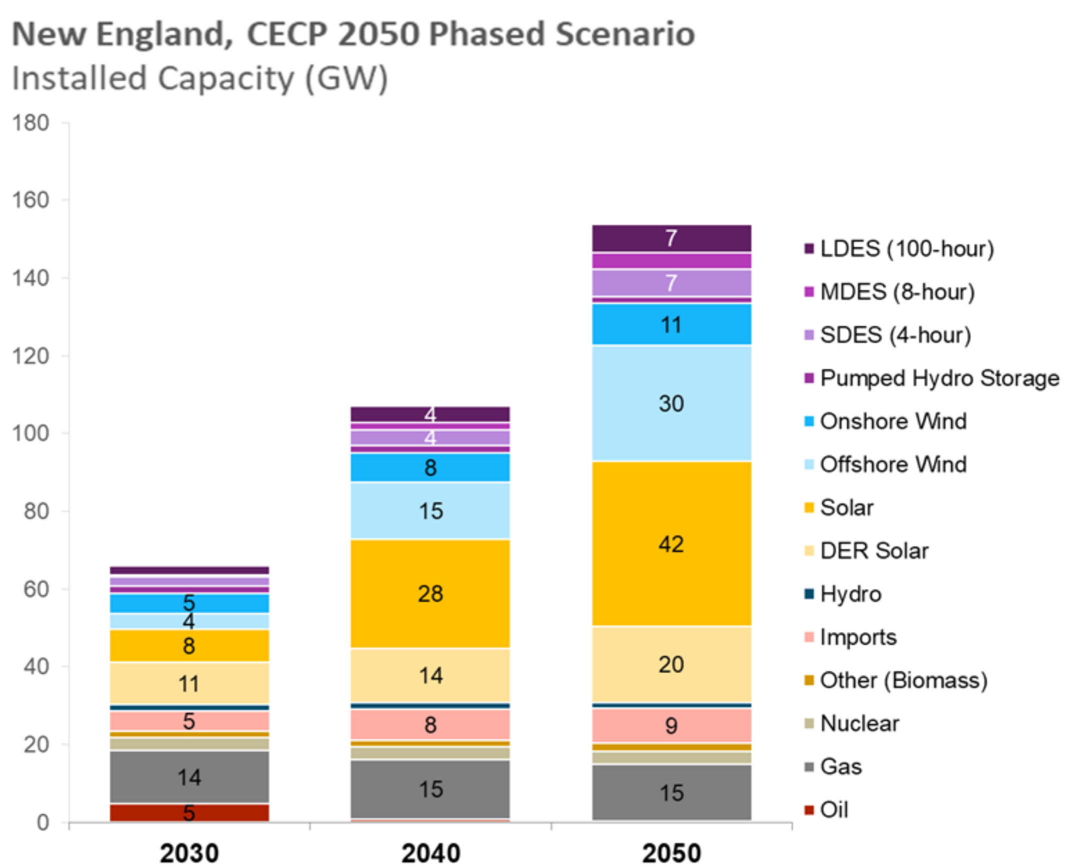


Source: (top) 2050 Transmission Study, ISO New England Inc, 2024, https://www.iso-ne.com/; (bottom) Massachusetts Clean Energy and Climate Plan 2050, https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/

Resource Forecasts

In parallel, studies and planning efforts show that New England's electric grid will transform in the coming decades to meet growing demand described above, while achieving state and regional policy targets aligned with Net Zero. By 2050, projections indicate that over 100 GW of renewable capacity could be developed in New England—more than three times the current installed capacity of the grid. This includes tens of gigawatts of solar, wind, and energy storage, making renewable resources the primary source of electricity generation. While some firm resources—such as gas turbines, nuclear generation, and imports—are expected to remain critical to grid reliability, the overall system will rely increasingly on variable, carbon-free resources, particularly for energy generation. An example of this transformation is shown in Figure 14 below, which reports the build-out of the New England grid in 2030, 2040 and 2050. While these scenarios achieve high levels of decarbonized energy generation, they also expand the amount of "firm" or on-demand dispatchable generation. This includes retaining existing gas capacity, almost doubling the amount of firm import capacity and adding several GW of long-duration energy storage.

Figure 14. Example New England Electric Grid Resource Additions, from MA CECP 2050

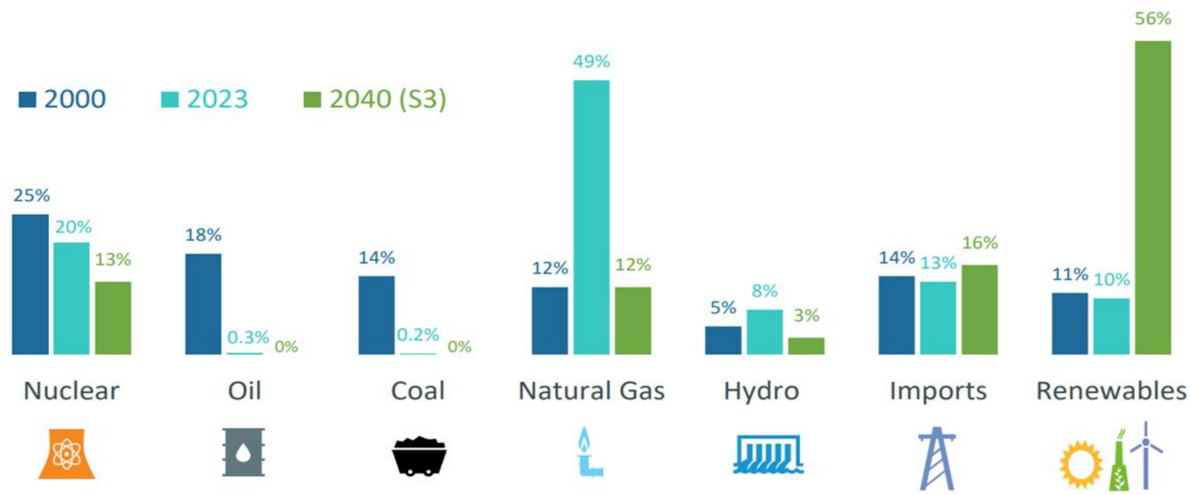


Note: This figure is after the removal of the renewable capacity that would need to be reserved to support electrolysis loads.

Source: Massachusetts Clean Energy and Climate Plan 2050, https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download

The state's planning shows the same pattern as studies done by ISO-NE, which similarly projects that from a generation perspective, the share of demand supplied by renewable energy will accelerate over the next 15 years, reaching nearly 60% of the generation mix (including hydro) by 2040 even as the total energy demand met by the electricity sector increases as well.

Figure 15. ISO-NE's Forecast of Total Electric Production by Source



Source: 2021 Economic Study: Future Grid Reliability Study Phase I, ISO New England Inc., 2022, https://www.iso-ne.com/

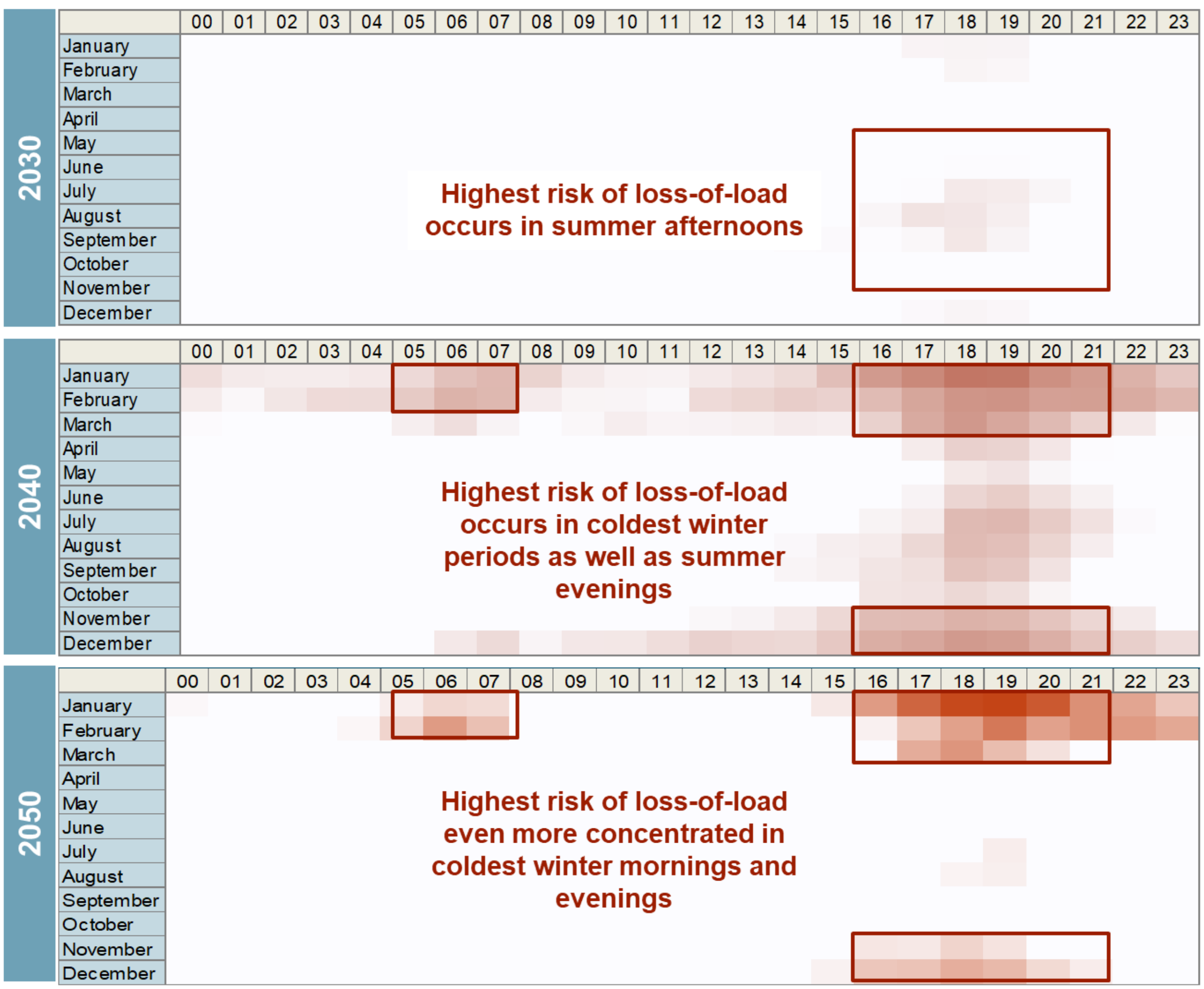
Resource Adequacy Needs from 2030 to 2050

New England's resource adequacy needs are expected to shift significantly over the next decade and through mid-century, driven by the dramatic load growth and renewable energy build-out described above. As significant renewable energy is added to the grid, gross total load is no longer the most accurate measure of when the electric system faces its greatest resource adequacy challenges. This is because renewable generation—particularly from solar and wind—can significantly reduce the amount of demand that must be met by dispatchable resources during certain hours. As a result, resource adequacy planning is increasingly focused on **net load,** rather than gross demand. Net load—defined as total electricity demand less variable renewable generation—provides a more accurate picture of the times when the system is most vulnerable and must rely on firm capacity to maintain reliability.

Figure 16 below illustrates how net load is expected to evolve from 2030 to 2050. In 2030, renewables begin to have a significant impact on the need for some sort of firm dispatchable generation. For example, in Massachusetts' CECP, the New England system is assumed to have almost 30 GWs of renewables, a majority of which come from solar. While solar contributes meaningfully during daylight hours, it declines rapidly in the late afternoon. As a result, the highest risk of loss-of-load events in the summer is expected to shift into early evening hours, particularly from 5 to 7 p.m. Although the region remains a summer-peaking system, maintaining resource adequacy in the winter is also becoming increasingly important, due to lower renewable output and higher electrified demand during cold, dark hours.

By 2040 and even more in 2050, continued electrification is projected to drive increases in electricity demand across New England, with peak system loads reaching double today. This marks a shift to a winter-peaking grid, with potential for two daily peaks—one in the morning and another in the evening—during the coldest winter months. The CECP 2050 estimates the grid could have roughly 100 GW of renewable resources by mid-century, widening the need for dispatchable resources. There still exists a spiky and short later afternoon peak but the system resource needs are stretched out across the day in cold winter months. By 2050, the high levels of renewable and storage build-out largely mitigate the summer needs, which are meaningfully higher than today but lower than winter needs.

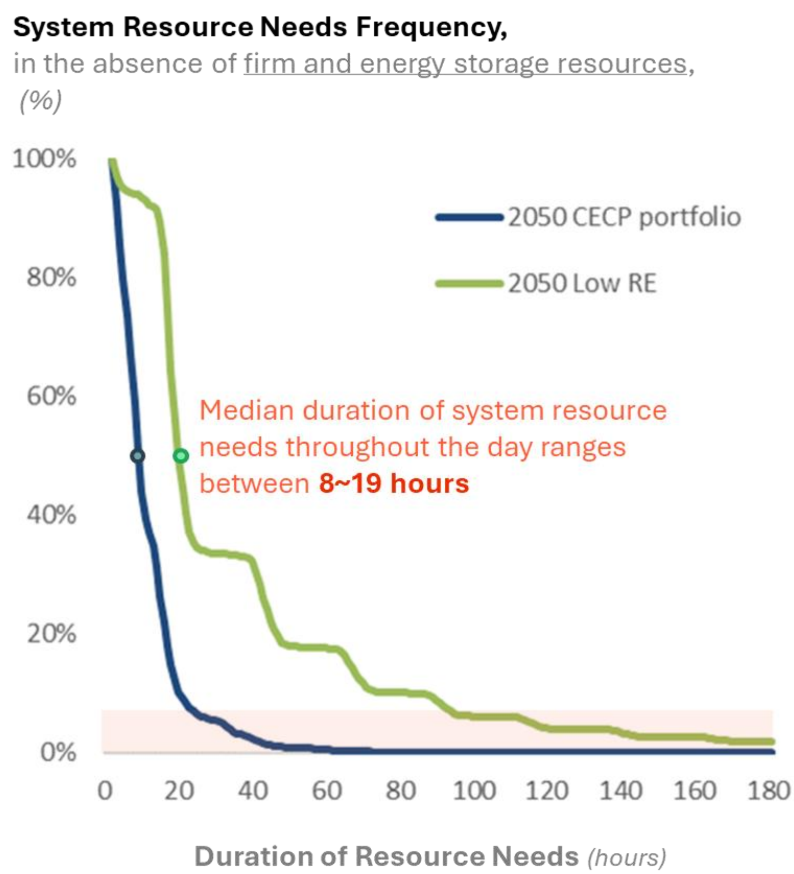
Figure 16. Average Month-Hour Net Load, Indicating Periods of Greatest Remaining Resource Need after Renewable Dispatch, based on CECP 2020 Portfolios



Source: Massachusetts *Charging Forward: Energy Storage in Net Zero Commonwealth*. Available here: https://www.mass.gov/guides/charging-forward-energy-storage-in-a-net-zero-commonwealth

As indicated by Figure 17, the capacity value of energy storage depends on the level of renewable energy deployment. When there is a significant build-out of renewables, as is the case under the 2050 CECP, storage has a higher and more sustained capacity value. Energy storage provides greater and longer-lasting capacity value as renewable penetration increases. In futures with high renewable deployment, half of the system resource gaps that last eight hours or less and can be met with short-duration storage. A mix of storage with 4-hour, 8-hour, and 100-hour durations are capable of meeting >99% of residual system resource needs if the 100GW of renewable energy forecasted in the CECP portfolio can be achieved. In scenarios with lower renewable energy development, longer-duration energy storage could be required to meet 95% of residual needs, with over 5% of system needs exceeding 100 hours including some gaps lasting several weeks.

Figure 17. Frequency and Duration of System Resource Needs

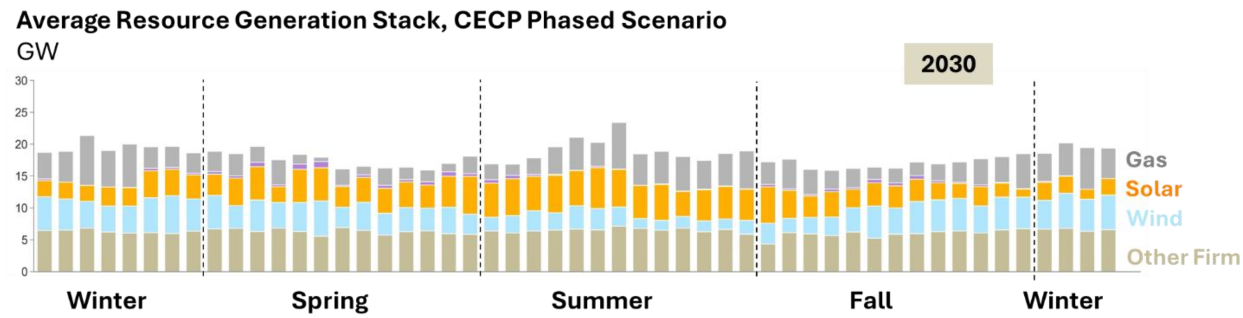


Source: Massachusetts *Charging Forward: Energy Storage in Net Zero Commonwealth*. Available here: https://www.mass.gov/guides/charging-forward-energy-storage-in-a-net-zero-commonwealth

The Role of Firm Generation

Across studies, renewable generation and storage are projected to displace much of today's fossil fuel generation, especially during the spring and summer months. Modeling of the future New England grid shows a significant decline in the system's reliance on firm generation—primarily natural gas and peaker plants—by 2030, with the annual utilization of the gas fleet declining even further by 2050. However, dispatchable capacity, particularly from gas peaker plants, remains critical during peak net load weeks. As shown in Figure 18, the system still depends on gas capacity during high-load summer and winter weeks during 2030, especially when it coincides with low renewable generation.

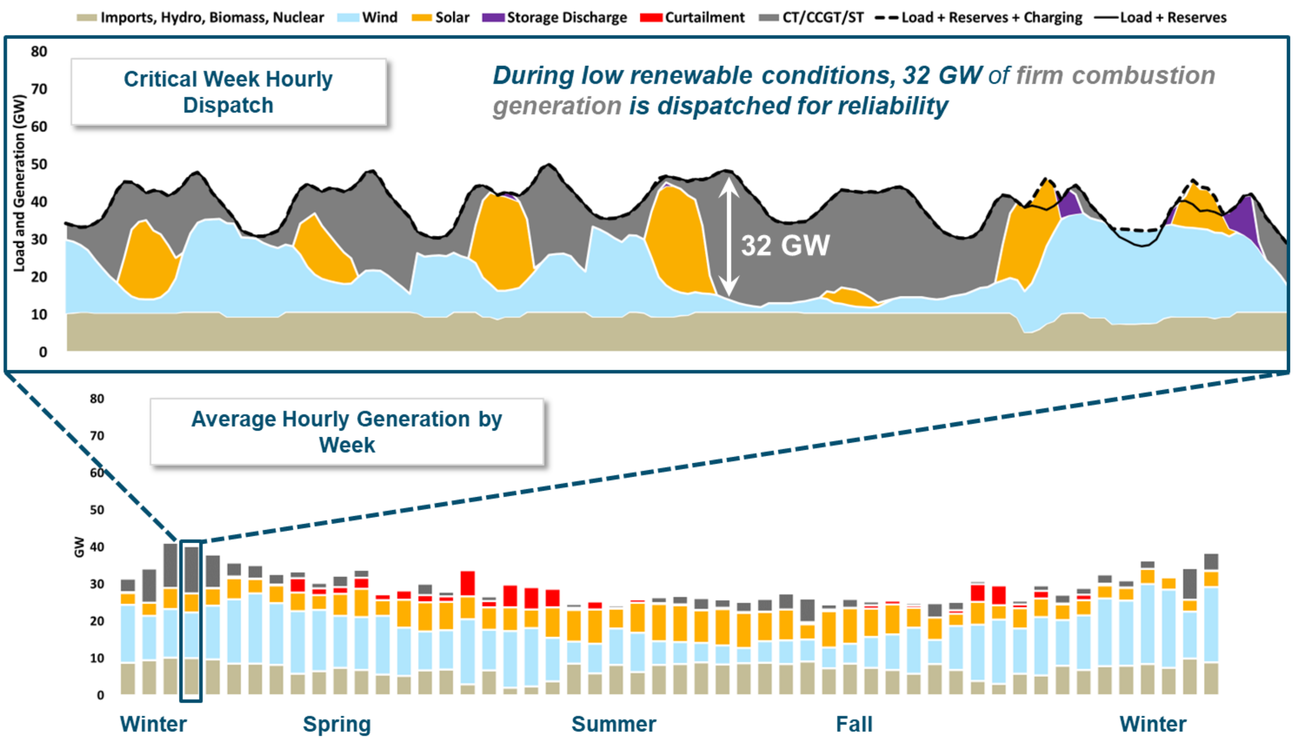
Figure 18. Example of Average Weekly Generation by Resource Type, Demonstrating Key Role of Gas Generation in Supporting 2030 Peak Net System Needs in Summer and Winter



Notes: This scenario is based on simulating hourly dispatch of the CECP Phased Scenario loads and resource portfolios from 2030 and reporting the average output across hours in each week. The "other firm" category includes imports, hydro, biomass, and nuclear generation.

By 2050, renewables meet the majority of energy demand over the course of the year, with firm resources supporting the system during a handful of weeks, primarily in the winter, with sustained higher loads and lower renewable outputs. This is illustrated in the figure below, from a modeled scenario of New England that meets Net Zero. While annual generation from the gas fleet, including peaker plants, is very low, the magnitude of firm capacity needed during the "critical" challenging week is larger than the size of today's gas fleet. This underscores a broader finding across many studies of resource adequacy in New England: critical reliability needs may remain similar – or even increase – relative to today's levels. For purposes of the FAWG evaluation of peaker plants, this underscores the point of evaluating not just how often resources run, but how reliably they can contribute during the system's most stressed conditions.

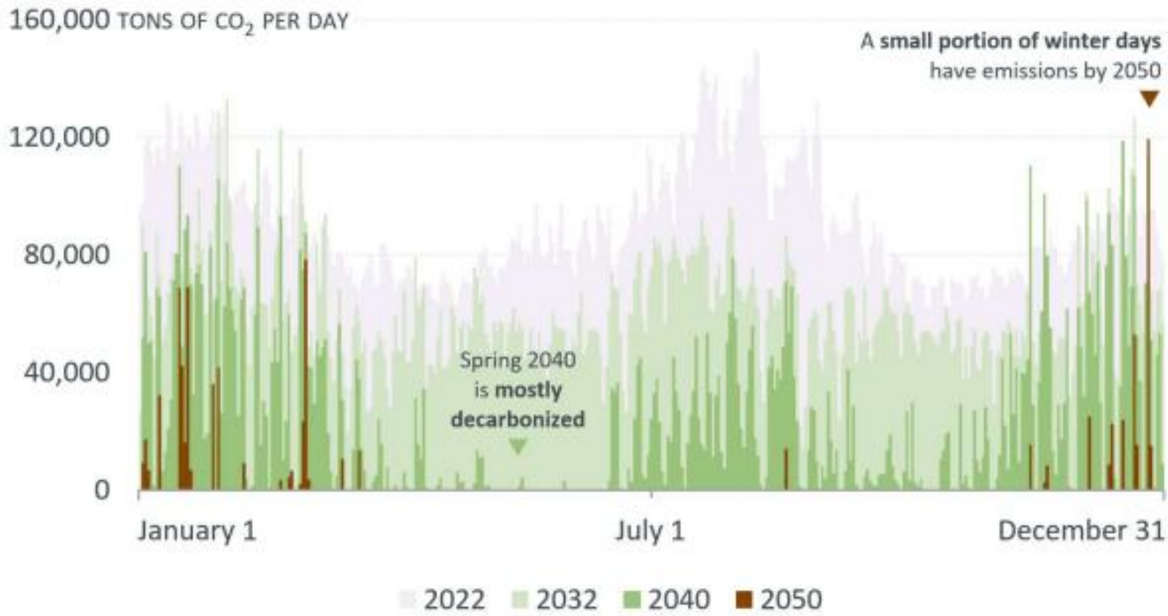
Figure 19. Example Average Resource Generation Stack by Week, in 2050 Under Net Zero Scenario



Note: E3 & Energy Futures Initiative 2050 Net Zero New England study. The firm generation capacity could represent any dispatchable generation. While today, this need is met with natural gas, in the future this could be met with another form of dispatchable generation (e.g., hydrogen, long-duration storage, carbon capture and storage, etc.).

The evolving resource mix, and the role of dispatchable generation, also has implications for the distribution of emissions over the course of the year, as illustrated in Figure 20. This figure illustrates the projected daily CO_2 emissions from the electric grid in New England across multiple years (2022, 2032, 2040, and 2050), demonstrating the transition toward a decarbonized system. Emissions are highest across most days of the year in 2022, with reductions by 2032 and substantial declines by 2040. In spring 2040, emissions are almost entirely eliminated, demonstrating a deeply decarbonized electricity mix during that season. However, even in the deeply decarbonized grid of 2050, the system still relies on carbon-emitting generation for a select number of winter days. This ongoing reliance on firm, dispatchable generation resources during critical days of peak demand and low renewable output highlights the challenge for achieving net-zero. While renewable energy, storage, and other zero-carbon resources can meet most of the system's needs throughout the year, maintaining reliability during the most stressed winter periods may still require limited dispatchable generation (which is today provided by fossil-fired resources).

Figure 20. ISO-NE's Forecast of Long-Term Decarbonization in Winter and Summer



Source: Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow's Grid, ISO New England Inc., 2024, www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf

Part 3: Next Steps and Recommendations for Future FAWG Activities

The DTP, EMT, and FTT FAWGs concluded Phase I and transitioned to Phase II with a debrief of key findings delivered to the ETAB in April 2025. This milestone marked broad agreement among participants on the foundational information reviewed and discussed throughout Phase I. Ensuring a shared understanding of the role of peaker plants, the limitations and opportunities for CHP facilities, and the evolving needs of the electric grid is important to ensure that stakeholders, both FAWG and ETAB members, can make informed decisions based on a common understanding. Consistent with this vision, several additional activities will occur and be considered by the DTP FAWG in Phases II and III, including:

1. **Finalize and apply the assessment framework, resulting in recommendations for technologies and policies for further evaluation in future phases.** The framework is not intended to select replacement resources or identify a single preferred solution. Rather, its purpose is to screen options across a variety of criteria. Several key steps will be helpful in using the framework to compare and potentially narrow the diverse range of potential technology alternatives:

    a. **Identify Any Potential Screening Thresholds:** The FAWG will refine decision criteria and build consensus around any potential thresholds (e.g., cost, emissions, technical maturity, feasibility) and decision rules for narrowing options through the framework.

    b. **Develop Peaker Archetypes:** Categorize full suite of Massachusetts peaker plants into distinct, relevant archetypes and apply the assessment framework to each archetype to inform recommendations. For example, archetypes may be based on size, utilization, fuel sources, location, grid services or other relevant factors. This segmentation will help identify which technologies or strategies are better suited for specific categories of plants.

    c. **Integrate Demand-side Modeling**: Incorporate the DOER load management study results as a set of potential options to evaluate alongside supply-side alternatives for reducing reliance on peaker generation.

    d. **Cost Analysis of Resource Alternatives**: Perform more detailed cost analysis of the existing and expected future capital and operational costs of different potential alternatives to peaker plants, which can inform both the framework assessment as well as potential future modeling. For example, this could involve more detailed evaluation of capital and operating costs under different timeframes and consider the impact of tax incentives, financing mechanisms, fuel price volatility, and potential cost declines due to technology learning curves.

2. **Perform portfolio-level electric grid reliability analysis of shortlisted options.** Understanding portfolio level impacts of replacing peaker plants with potential technology alternatives will be critical to ultimately reducing emissions related to peak demand and ensuring they are not just shifting to another time or resource. This analysis can be designed to answer key questions to inform the FAWG's recommendations, for example:
    a. **What do portfolios with replacement technologies need to ensure ongoing reliability standards are met under extreme conditions?** Loss-of-load probability modeling can evaluate system performance during a diverse range of load and weather conditions, including simulating multi-day weather events (e.g., cold snaps, heat waves) and periods of low renewable output. This may be used to evaluate the implications of replacing multiple peaker plants, and may also evaluate potential interactions across technologies and the ability of combinations of resources to replace or reduce reliance on peaker plants.
    b. **What are the emissions and cost implications of different pathways to replace or reduce reliance on peaker plants?** The modeling can also evaluate, for example, how potential future portfolios that replace or reduce reliance on peaker plants perform in terms of other key metrics, such as total emissions and costs. For example, the modeling can evaluate whether replacement resources reduce net emissions or if the system shifts the emissions to another resource or time. Similarly, the fixed and variable costs of the system can be evaluated.
3. **Identify priority subset of facilities for potential near-term action.** The screening framework and modeling can help the FAWG to understand where there appears to be the most impactful opportunities for decarbonization measures and which facilities represent the most feasible opportunities for near-term conversion. This be important for translating the work of the DTP FAWG into actionable results.

4. **Conduct a deeper assessment of barriers to deployment.** While the DTP FAWG examined several constraints to implementation, a more comprehensive analysis and associated action plan will be important to overcome impediments. Specific concerns—for example, long interconnection queues, permitting challenges, supply chain delays, and cost uncertainty—will impact the pace at which the Commonwealth can achieve its goals. The FAWG can build out a comprehensive list of existing and potential barriers, assess risks, and identify areas where reforms may be needed (e.g., policy, markets). A summary action plan can identify key strategies for mitigating potential barriers where feasible.

5. **Investigate further how policy and market futures might influence facility economics and operating decisions.** Legislation and regulation, both at the federal and state levels, and ISO-NE actions, for example the transition from forward annual capacity auctions to a prompt seasonal model, are likely to have significant impacts on how peak resources enter, exit, or operate in the market. Leveraging a detailed pro forma financial model could show how different policy and market futures would impact facility compensation and

demonstrate how facility economics may change under different policy mechanisms and market futures.

Together, the above activities may help the DTP FAWG to create forward-looking recommendations and perspectives on viable pathways to help decarbonize electricity generation in Massachusetts, while ensuring ongoing reliability and affordability in the Commonwealth.