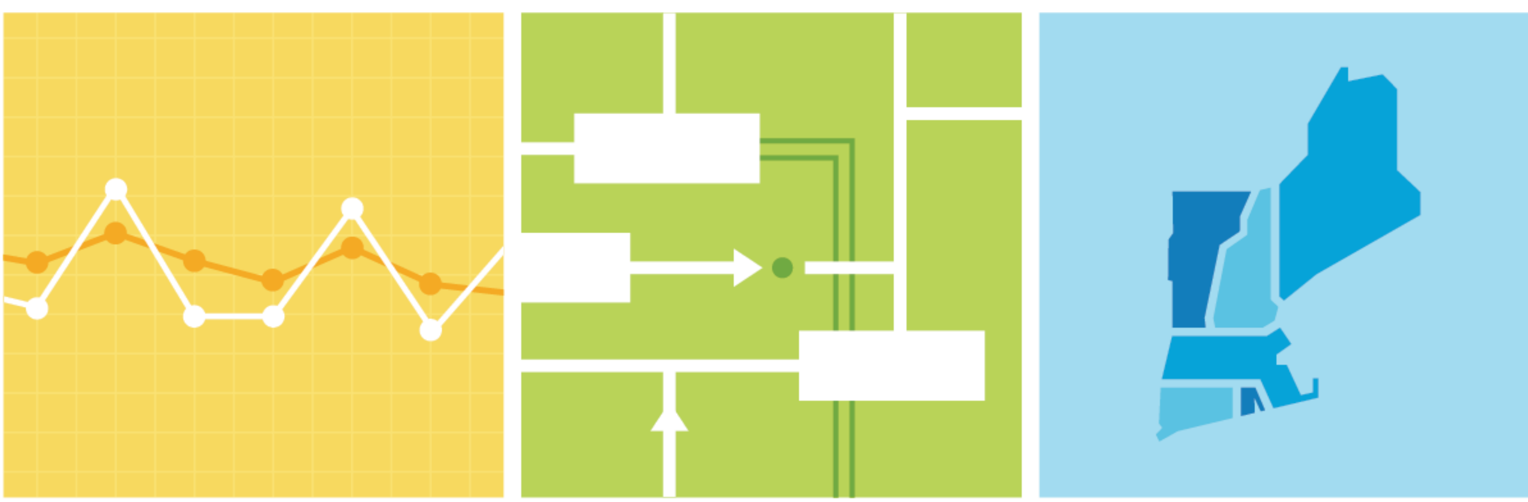
2024 Annual Markets Report

Internal Market Monitor

MAY 23, 2025



Document Revision History		
Date	**Version**	**Remarks**

Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2024 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2024. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Appendix A, Section III.A.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[2]

This report presents key findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2024. The executive summary gives an overview of the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Sections 1 through 9 include more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report.

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[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation", available at http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

[2] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.[3]

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

Underlying oil and coal pricing data are furnished by Argus Media.

[3] See ISO's *Financial and Performance Reports*, available at https://www.iso-ne.com/about/corporate-governance/financial-performance.

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Executive Summary

The 2024 Annual Markets Report by the Internal Market Monitor (IMM) at ISO New England (ISO) addresses the development, operation, and performance of the wholesale electricity markets. The report presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electricity in the day-ahead and real-time markets, the participants in the forward and real-time markets buy and sell operating reserve products, regulation service, financial transmission rights, and capacity. These markets are designed to ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

As additional background, the supporting document titled "An Overview of New England's Wholesale Electricity Markets: A Market Primer" may assist readers with understanding the fundamental concepts and mechanics of the wholesale markets.[4]

In this executive summary, we provide an overview and assessment of key market trends, performance, and issues. We follow this with a consolidated list of recommended enhancements to the market design and rules from this and prior IMM reports.

The capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2024. Day-ahead and real-time energy prices continued to reflect changes in primary fuel costs, electricity demand, and the region's evolving supply mix. Tight system conditions and scarcity pricing remained rare, with operating reserves falling short of requirements for only 2.3 hours (approximately 0.03% of the year). These events were brief and moderate, with the system recovering quickly and no load shedding required. During these periods, the markets provided transparent and strong price signals that incentivized resource performance.

Energy market prices increased by 13% in 2024 compared to 2023, driven by higher production costs and shifts in the regional supply mix. Two key contributors were higher CO_2 emissions costs under the Regional Greenhouse Gas Initiative (RGGI) and a sharp decline in imports from Quebec. By contrast, natural gas prices—the primary driver of electricity prices in New England—remained relatively stable, averaging $3.06/MMBtu in 2024. While elevated gas prices occurred during cold winter periods due to pipeline constraints, prices during warmer periods tracked historically low Henry Hub and Marcellus prices, reflecting high natural gas storage levels.

Changes to the energy supply mix were driven by a near 30% year-over-year reduction in imports to the region. The decrease in imports was primarily due to extended dry weather conditions limiting hydroelectric generation in Canada. Increased output from natural gas-fired and nuclear generation offset the lower imports, while wholesale demand increased by just 2% (or 200 MW per hour).

High-level market statistics for the five-year period covered in this report are presented below.

[4] See *An Overview of New England's Wholesale Electricity Markets: A Market Primer* (June 2023), available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf. This document will be updated periodically, particularly to reflect changes to market design such as the upcoming Day-Ahead Ancillary Services Initiative.

At a Glance: High-level Market Statistics

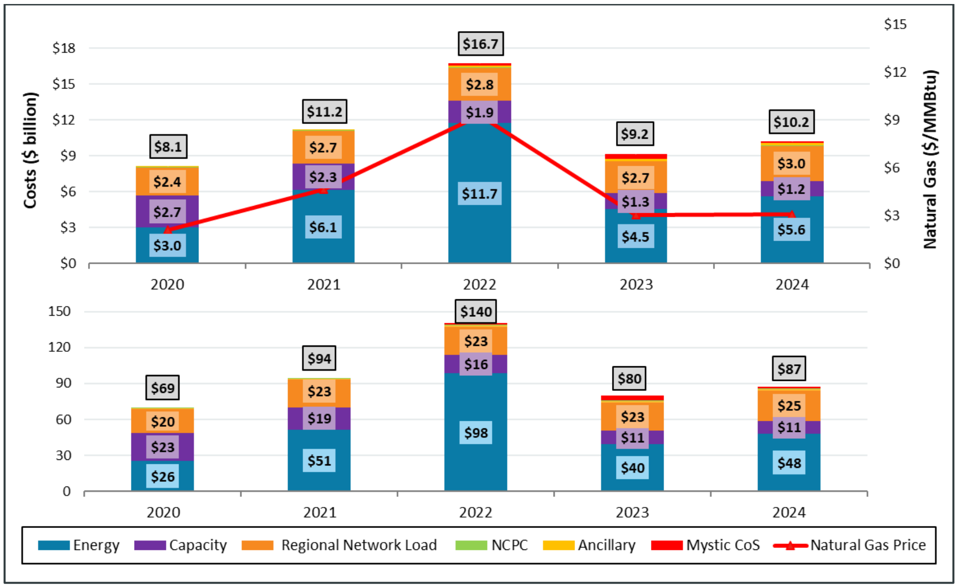
Demand (MW)	2020	2021	2022	2023	2024	% Change '23 to '24	Sparkline
Load (avg. hourly)	13,305	13,561	13,576	13,096	13,294	2%	
Weather-normalized load (avg. hourly)[a]	13,242	13,419	13,514	13,132	13,226	1%	
Peak load (MW)	25,121	25,801	24,780	24,043	24,871	3%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	16.34	36.07	72.57	23.76	23.83	0%	
Coal	37.82	67.77	144.87	69.19	58.89	-15%	
No.6 Oil	89.42	138.21	221.17	164.97	154.96	-6%	
Diesel	112.07	184.50	331.99	253.42	217.37	-14%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	23.31	45.92	85.56	36.82	41.47	13%	
Real-time (simple avg.)	23.37	44.84	84.92	35.70	39.50	11%	
Day-ahead (load-weighted avg.)	24.57	48.30	91.36	39.19	44.52	14%	
Real-time (load-weighted avg.)	24.79	47.34	91.13	38.25	42.47	11%	
Estimated Wholesale Costs ($ billions)							
Energy	3.0	6.1	11.7	4.5	5.6	24%	
Capacity[c]	2.7	2.3	2.0	1.8	1.4	-22%	
Uplift (NCPC)	0.03	0.04	0.05	0.03	0.03	1%	
Ancillary Services[d]	0.1	0.1	0.1	0.2	0.2	7%	
Regional Network Load Costs	2.4	2.7	2.8	2.7	3.0	11%	
Total Wholesale Costs	**8.1**	**11.2**	**16.7**	**9.2**	**10.2**	**11%**	
Supply Mix [e]							
Natural Gas	42%	45%	45%	48%	50%	2%	
Nuclear	22%	22%	23%	20%	22%	2%	
Imports	20%	16%	14%	13%	9%	-4%	
Hydro	7%	6%	6%	8%	7%	-1%	
Other[f]	5%	5%	4%	4%	5%	0%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	2%	2%	3%	3%	4%	0.6%	
Coal	0%	0%	0%	0%	0.2%	0.04%	
Oil	0%	0%	2%	0%	0.3%	-0.01%	
Battery Storage	0%	0%	0%	0%	0.3%	0.10%	

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Capacity costs in 2022-2024 include Mystic cost-of-service costs
[d] Ancillary Services include inventoried energy program costs
[e] Provides a breakdown of total supply, which includes net imports; Note that section 1.2 provides a breakdown of native supply only
[f] The "Other" fuel category includes landfill gas, methane, wood, refuse and steam
⇨ denotes change is within a band of +/- 1%
Sparkline: Green = High Point, Red - Low Points

Higher energy costs drove a $1 billion increase in wholesale costs due to higher carbon emissions prices and fewer net imports

In 2024, the total wholesale cost of electricity rose to $10.2 billion, or about $87 per MWh of load served—an 11% increase over the 2023 total of $9.2 billion. This uptick was mainly driven by a 24% rise in energy market costs, which reached $5.6 billion.

Flat Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs remained the largest component of wholesale electricity costs, accounting for 55% of the 2024 total. The increase was driven by higher input costs and changes in the supply mix, including increased CO_2 emissions costs under the Regional Greenhouse Gas Initiative (RGGI) program and reduced net imports from Quebec. Natural gas prices remained steady, averaging $3.06/MMBtu in 2024 compared to $3.04/MMBtu in 2023. The previous year had seen a sharp 43% drop in wholesale costs from $16.7 billion in 2022, largely due to a significant decline in natural gas prices.

Transmission costs, at $3 billion, comprise 30% of total costs and have increased in recent years due to investments addressing ISO-identified reliability needs, replacement of aging infrastructure through asset condition projects, and broader inflationary pressures.

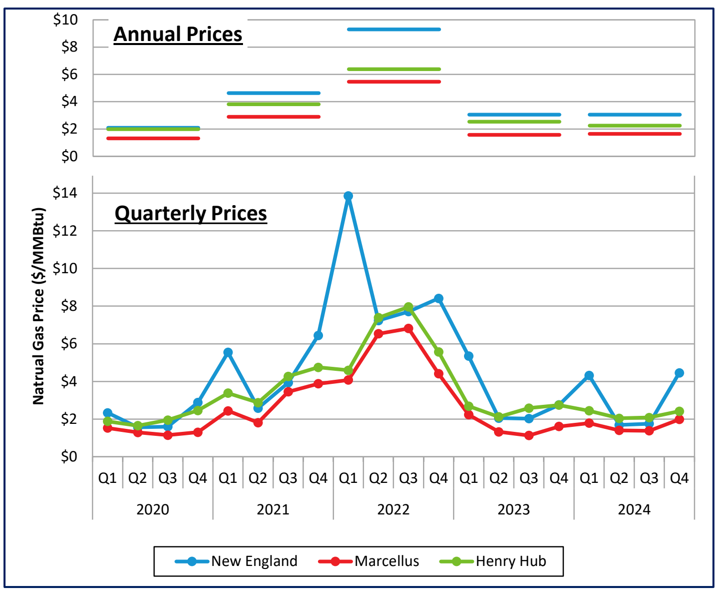
Capacity costs totaled $1.2 billion in 2024, accounting for 12% of total wholesale electricity costs—a 5% decrease from 2023. The decline reflects continued surplus capacity (~1,300 MW) in the region and relatively low clearing prices in the capacity auctions. Prices averaged $2.00/kW-month during the fourteenth capacity commitment period (CCP 14, 2023/24), increasing modestly to $2.61/kW-month in CCP 15 (2024/25), well below the average Net Cost of New Entry parameter for both auctions of $8.45/kW-mo.

Uplift costs, or Net Commitment Period Compensation (NCPC), totaled $34.7 million in 2024—essentially unchanged from 2023—and represented a small portion of total energy costs at 0.6%, slightly lower than the prior year. As in past years, the majority of NCPC payments (91%) were for first contingency or “economic” commitments—covering the operating costs of resources committed in merit order to meet load and reserve requirements. Payments for reliability services remained minimal. Notably, payments under the Mystic Cost of Service (CoS) agreement totaled $139 million in 2024—more than four times higher than NCPC—equating to $1.19/MWh of load served. That agreement expired in May 2024, when the Mystic combined cycles retired.

Natural gas prices were flat year-over-year and remain the key driver of energy prices, but rising CO_2 costs had a greater impact on year-over-year energy price changes

In 2024, natural gas prices remained relatively low, averaging $3.06/MMBtu for the year—similar to 2023. During the non-winter months, New England prices fell below $2.00/MMBtu for the first time since 2020, tracking historically low Henry Hub and Marcellus prices supported by high storage levels. However, limited pipeline capacity during colder periods led to elevated winter prices, with Q1 and Q4 averages exceeding $4.00/MMBtu—more than $2.00 above national hub prices—and daily prices spiking above $10.00/MMBtu on 22 days in January and December. These seasonal price swings influenced generator behavior, with lower gas prices outside of winter contributing to high utilization of gas-fired generators and relatively low LMPs during mild weather.

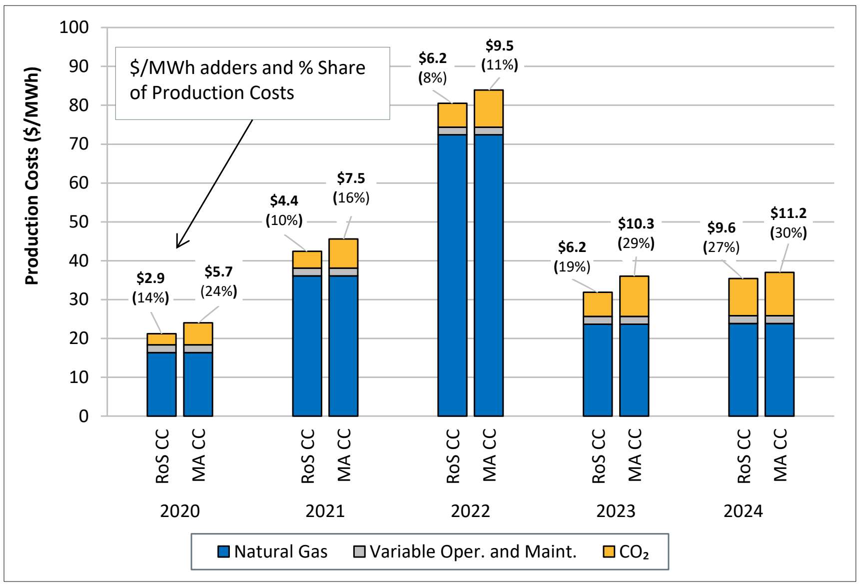
Tighter Spread between New England and Henry Hub, Marcellus Natural Gas Prices



Despite stable national prices at Henry and Marcellus hubs, New England remains susceptible to winter price volatility. Looking ahead, the EIA projects rising Henry Hub prices—$3.10/MMBtu in 2025 and $4.00/MMBtu in 2026—driven by growing demand, particularly for LNG exports. In New England, future gas prices will likely continue to reflect both broader market trends and regional pipeline constraints, with higher emissions costs further increasing the cost of gas-fired generation.

New England has two carbon-reducing cap-and-trade programs that affect generator production costs and electricity prices: (1) the Regional Greenhouse Gas Initiative (RGGI), which applies to generators in all New England states, and (2) the Massachusetts Electricity Generator Emissions Limits (MA EGEL), applicable only to Massachusetts generators. In 2024, carbon allowance costs made up a larger share of fossil fuel generation costs than in prior years, primarily due to rising RGGI prices. RGGI allowance prices reached record levels in 2024—averaging \$21 per short ton of CO_2, up 55% from 2023. CO_2 costs accounted for 11–13% of production costs for oil-fired generators and up to 30% for natural gas-fired generators, making them a significant driver of energy prices. We estimate that CO_2 compliance costs added approximately \$8/MWh to the average annual load-weighted energy price and contributed about \$910 million to total energy costs.[5]

Breakdown of Estimated Combined Cycle (CC) Production Costs by Component[6]



Net interchange with Canada continued to decrease

In 2024, real-time net interchange averaged 1,175 MW per hour—meeting approximately 9% of real-time load—and marked the lowest level of net imports since 2011. This continued decline was primarily driven by dry weather conditions in Québec.

According to the U.S. Energy Information Administration (EIA), 2023 saw a significant decline in electricity exports from Canada across both the Eastern and Western Interconnections with the United States, driven in part by reduced hydropower generation in Canada.[7] Flows into MISO, NYISO and New England from neighboring Canadian provinces were substantially lower than historical levels. This trend persisted into 2024.

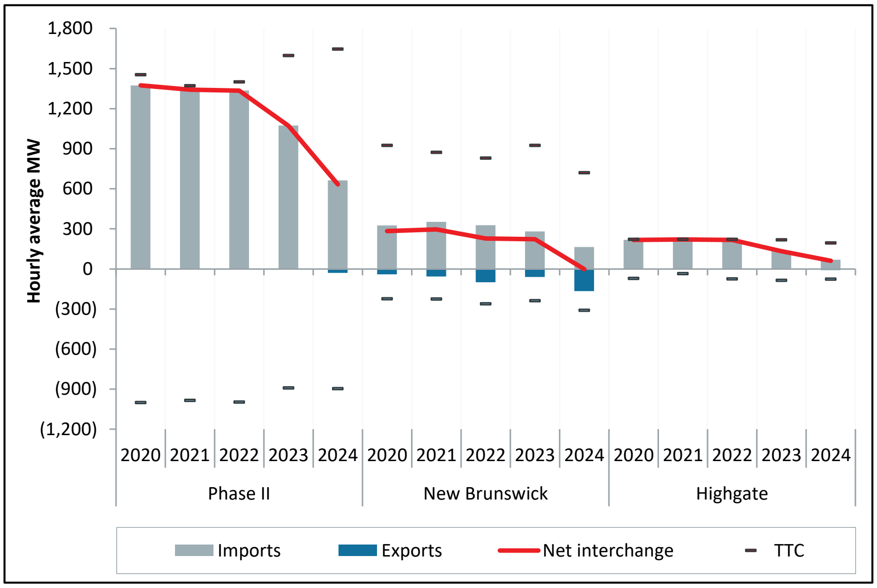
[5] The net costs of the CO_2 emission programs are significantly lower (than the estimated wholesale energy cost impact) as the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs, clean and renewable energy. For instance, the majority of auction proceeds from RGGI are invested by the New England States in energy efficiency programs, which have had a significant impact on reducing wholesale demand and wholesale energy costs (see Section 1.5). Similarly, the majority of proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions.

[6] RoS CC = Rest of System Combined Cycle generators to which RGGI costs apply. MA CC = Massachusetts Combined Cycle generators to which both RGGI and MA GWSA costs apply. The estimated costs are based on an average heat rate of 7.8 MMBtu/MWh.

[7] See *U.S. electricity exports to Canada have increased since September 2023* (November 12, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=63684

Canadian interfaces, which accounted for over 80% of net interchange in 2023, contributed just under 60% in 2024. Despite the overall decline, net imports remained a critical resource during high-load periods, averaging nearly 2,700 MW per hour on days when load exceeded 20,000 MW.

Net interchange between New England and Canada fell substantially for the second consecutive year



Imports from Québec continued to fall across both Phase II and Highgate.[8] At Phase II, average net imports dropped to 633 MW per hour—down 53% from the 2020–2022 average of 1,351 MW—while Highgate imports declined to just 61 MW per hour. In New Brunswick, a nuclear generator took an extended outage that lasted from April 2024 to December 2024 resulting in lower net imports into New England.

Flows over the New York North interface increased for the second year in a row, supported by infrastructure upgrades in New York, while exports to Long Island over the Cross Sound Cable and Northport-Norwalk interfaces remained relatively stable. At the New York interfaces (not shown above), net interchange helped offset some of the drop in Canadian imports, with New England importing a net 483 MW per hour in real time.

The evolving demand and supply landscape and market implications

The New England states are making significant investments in the power sector to support their decarbonization goals, including funding for energy efficiency measures, storage, and renewable generation at both the wholesale and retail levels.

Overall, the contribution of renewables to meeting gross demand increased from 17.7% to 19.1% over the past five years. However, at the wholesale level, the share remained flat at 16%, as higher solar output was offset by reduced hydroelectric generation due to drought conditions and a decline in other renewable sources. Looking ahead, the commissioning of major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704

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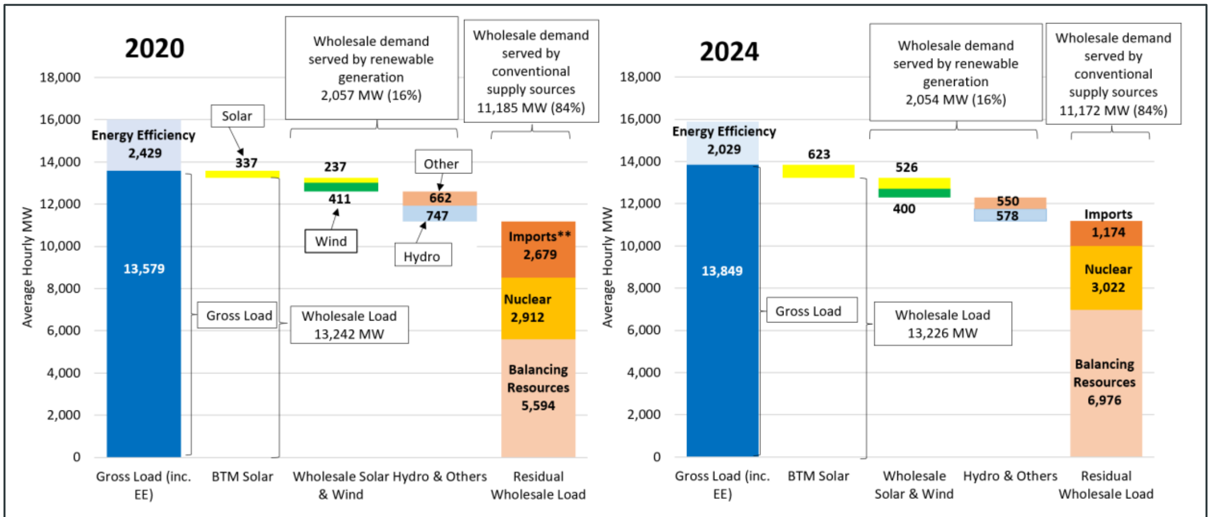
[8] For more information on Québec's reduction in exports, see Hydro-Québec's *Annual Report 2024*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/M1029-22024G415-rapport-annuel-2025-03-en.pdf.

MW), and the New England Clean Energy Connect (1,200 MW) transmission line—would significantly expand the region's renewable energy portfolio over the coming years.

A Five-Year Snapshot of Demand and Supply, 2020 vs. 2024



* Other renewable sources include biomass, wood waste, refuse, landfill gas and methane.
** The net import value includes imports backed by renewable forms of generation.

Long-term studies such as the ISO's Economic Planning for the Clean Energy Transition (EPCET) and the Analysis Group's Pathways study provide important insights into the operational and market impacts of large-scale renewable integration, including implications for pricing, resource balancing, and evolving load and generation patterns.[9,10] While current impacts remain modest due to relatively stable load and limited incremental renewable growth, this report establishes a framework for monitoring key trends identified in long-term studies, which are expected to become more significant as the clean energy transition progresses in future years.

The main body of this report provides analysis on several key areas that relate to the EPCET and Pathways studies that are not covered in detail in this executive summary, including:

- Profitability and/or net revenues of new and existing supply resources (0)
- Changes in load profiles and resulting demand for flexible supply (1.5.3, 1.5.4)
- Energy price impacts and trends in negative supply offers (1.5.2, 3.1.2)
- Load uncertainty and forecasting challenges (1.5.5, 1.5.6)

Low levels of structural market power and mitigations in the energy market

Market outcomes were competitive overall, and the exercise of market power was generally not a concern. Although price-cost markup metrics in both the day-ahead and real-time markets were higher than in previous years, they remained well below the tightest mitigation threshold

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[9] See the ISO's *Economic Planning for the Clean Energy Transition* report (October 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf

[10] See the Analysis Group's *Pathways Study* (April 2022), available at https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf

of 10%. These results indicate that competition among suppliers effectively limited the ability to inflate LMPs by submitting offers above marginal cost.

The top four suppliers controlled 40% of real-time supply and 55% of demand, consistent with historical averages and not highly concentrated in any single firm. The frequency of pivotal suppliers declined slightly, occurring in 33% of real-time hours compared to 37% in 2023; the average Residual Supply Index (RSI) improved from 103.5 to 104.2, reflecting fewer generator outages.

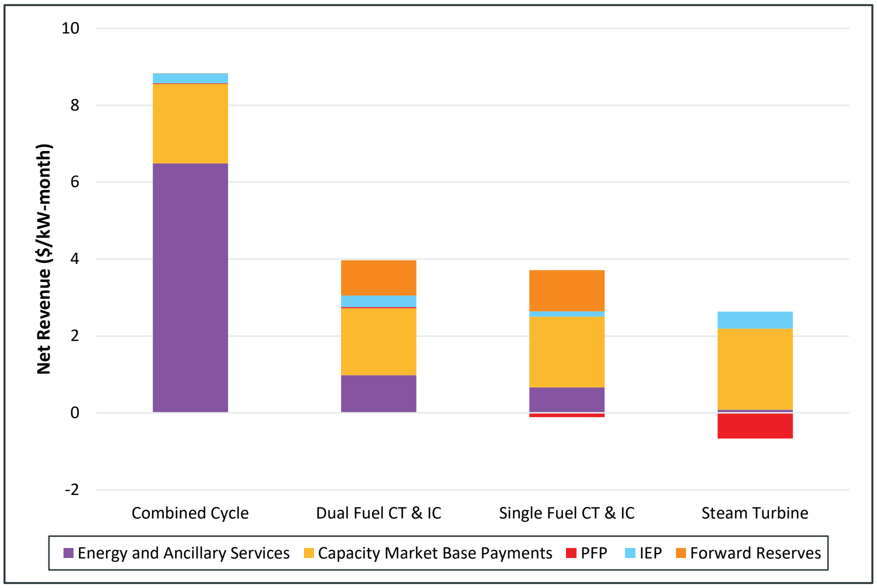
In the day-ahead and real-time markets, annual load-weighted markups—a measure of price impacts due to above-cost offers—had been close to zero or negative from 2020 to 2023 but increased in 2024 to 2.4% and 6.8%, respectively. This increase was primarily driven by gas-fired generators offering above marginal cost, whereas historically much of their capacity had been offered below FPA-adjusted reference levels. Despite the rise in markups, economic withholding remained limited in 2024, with the output gap—a measure of withheld capacity due to above-cost offers—staying below 2%.

A breakdown of revenue streams from wholesale electricity markets by generator technology provide some indication of new investment and exit signals

Market-based revenues were insufficient to cover the going-forward costs of new entrant gas-fired generators. The profitability of wind and solar units in the region remains intricately linked with state policies, with both technologies generally relying on additional revenue streams to those in the wholesale markets to be economically viable. Net revenues for the typical battery resource in the region have steadily decreased since 2021, driven largely by a decline in regulation service revenues.

In terms of existing resources, combined-cycle (CC) plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have relied on the capacity market to a greater extent. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market over the same period. These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

Existing Resource Net Revenues from Energy, Capacity and Ancillary Markets in 2024 show Significant Variation across Technologies



Capacity Auction Reforms (CAR) - the benefits of low barriers to exit and a robust market power mitigation framework

The Capacity Auction Reform (CAR) project is a multi-year initiative aimed at overhauling key aspects of the capacity market, including auction timing, seasonal procurement, and capacity qualification and exit (deactivation) rules. These changes are critical to improving the cost-effectiveness of how the market procures and prices capacity to meet its resource adequacy goals. By moving away from the current structure—where capacity is procured more than three years in advance—the revised design better aligns the market with the varying and uncertain timelines for new resource development, decision timing on resource exit, the uncertain pace of peak load growth, and reliability risk profile that varies by season.

Efficient coordination of resource entry and exit is essential for maintaining system reliability and cost-effectiveness in New England's wholesale electricity markets. Given uncertainty around future demand growth—driven by electrification of transportation and heating—and supply-side challenges such as permitting and procurement delays, it is important that the market design promote flexibility for both supply- and demand-side solutions.

Near term, New England remains long on capacity with prices well below Net CONE, prompting retirements of existing resources reaching the end of their economic lives. Over time, as the supply-demand balance tightens, the potential reactivation of retired resources may be a cost-effective solution. To support efficient outcomes, it would be reasonable to remove the current $417/kW repowering threshold, which requires a resource owner to make a substantial capital investment to return to the capacity market. The threshold serves as an unnecessary barrier to efficient exit and re-entry.

Further, allowing limited revocability of deactivation notifications could enhance flexibility. We believe there is merit in allowing for the cancellation of deactivation notifications, recognizing that a resource's economic outlook may change after the currently proposed two-year notification time. This revocation window should end sufficiently in advance of the existing capacity qualification deadline for the CCP but should be sufficiently long to provide economic benefits to the region.

However, introducing this flexibility requires careful rule design to preserve the integrity of the power system and market power study processes (e.g., deter information or RMR fishing[11]), and to promote the efficient release of scarce transmission capacity for potential new entrants. One potential safeguard could be a requirement that the participant demonstrate to the satisfaction of the ISO or its IMM that the resource's economic conditions have materially improved before it is permitted to reverse its retirement plans.

The CAR initiative requires a review of the current mitigation rules to ensure consistency with a prompt and seasonal market, and with new accreditation rules. It also provides an opportunity to ensure that the rules are aligned with sound market power mitigation principles. In this regard there are improvements that can be made to the seller-side mitigation rules that apply to existing resources submitting capacity offers for a single delivery period. Specifically, we recommend that the ISO introduce a Conduct and Impact (C&I) test framework to replace the current Pivotal Supplier Test (PST). There are number of potential benefits to introducing a C&I framework, including:

- a more accurate assessment of market power;
- a consistent mitigation framework;
- a C&I approach could reduce the influence of the conduct review threshold value (currently known as the Dynamic Delist Bid Threshold or DDBT); and
- a C&I approach could conceptually incorporate buyer-side mitigation rules.

In this report, we add a further five new recommendations regarding market enhancements

In addition to our recommendation to adopt a Conduct and Impact framework for seller-side capacity market mitigation, we introduce five new recommendations to potentially improve the design and operation of the wholesale markets,

First, there are a number of areas where the capacity market rules can be enhanced that are not directly related to the scope of the aforementioned CAR project, but should nonetheless be considered. Here, we make recommendations in three areas. The first relates to the allocation of capacity charges, specifically Pay for Performance (PfP) charges to exports during Capacity Scarcity Conditions. The next two recommendations relate to areas of the rules which generate issues or concerns around market compliance for market participants. We think the marketplace would benefit from improvements to the Tariff language to enhance clarity.

- *Pay-for-Performance Treatment of Exports*
  We agree with the External Monitor's recommendation on this, which we supplement with our own recommendation.[12] The current Pay-for-Performance (PfP) structure creates unequal incentives for imports and exports during scarcity events, crediting

[11] Reliability Must Run (RMR) fishing refers to a practice where a resource owner may be incentivized to submit a speculative retirement notification to determine whether the resource is needed for reliability and thus eligible for a cost-of-service agreement. If it is not deemed necessary, the owner can simply withdraw the notification.

[12] The External Market Monitor's recommendation can be found in the *2023 ISO New England Assessment of the ISO New England Electricity Markets* (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/07/ISO-NE-2023-EMM-Report_Final.pdf

imports at the PfP rate but not applying the same charges to all exports. This misalignment can lead to inefficiencies and potential gaming opportunities, where related participants profit from simultaneous imports and exports with minimal risk and no reliability benefit. While both increased imports and reduced exports can help resolve reserve deficiencies, only imports are financially rewarded under current rules. For example, during scarcity events on June 18 and August 1, 2024, New England exported over 800 MW to neighboring regions, despite the system being short on reserves. To address this we recommend that ISO-NE update the Tariff to apply the PfP rate symmetrically to exports, aligning financial incentives and ensuring that external transactions—whether imports or reduced exports—are valued equally for their contribution to system reliability.

- *Provide Clarity on the Need to Shed a CSO During Outage Periods*
  The Tariff requires non-intermittent resources to offer their full Capacity Supply Obligation (CSO) unless they are physically unavailable, but it lacks clear definitions and enforcement mechanisms for prolonged unavailability. The IMM considers a resource physically available if it is not on a forced or planned outage, consistent with other Tariff provisions and FERC rulings. However, resources can remain on outage and continue receiving capacity payments without being required to shed their CSO, which has led to enforcement actions in the past. Given the range of unavailability scenarios—such as early retirements, long-term outages, lack of fuel, or insufficient backing of demand response resources—the IMM recommends amending the Tariff to better define physical unavailability and to require resources to shed their CSO or face penalties if they cannot deliver capacity for extended periods.

- *Review and Clarify the Time-Out Trigger for Capacity Resource Retirements and Termination of Interconnection Rights*
  The current market rules state that a resource will be considered retired, and its interconnection rights terminated, if it does not "operate commercially" for three calendar years—a rule intended to support the efficient reallocation of unused transmission capacity. However, the term "operate commercially" is not clearly defined, allowing resources to retain rights by producing minimal energy output, even without plans to return to full operation. To prevent inefficient use of transmission capacity, the IMM recommends clarifying the Tariff to require that a resource demonstrate meaningful and sustained energy production to be considered commercially operational.

The final two recommendations address additional areas for market and system improvements. First, we recommend evaluating the market clearing mechanism for external transactions at non-CTS interfaces. Second, we recommend a system enhancement (a market rules change is likely not required), to address an operational issue identified when renewable resource owners failed to overwrite their cleared day-ahead offers with their intended real-time offers, resulting in lower renewable generation output. Implementing these enhancements would improve market efficiency and better align dispatch with resource capabilities and costs.

- *Clearing Mechanisms used at External Interfaces*
  Participants have increasingly used virtual demand bids at the Highgate interface to secure real-time clearing priority for their imports. By pairing virtual demand bids with early-submitted import offers, up to 40 days in advance of the operating day,

participants can create counter-flow in the day-ahead market, enabling full clearing of their imports and gaining a timestamp advantage in real-time scheduling.

While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time. Accordingly, we recommend that ISO-NE reevaluate clearing rules at non-CTS external interfaces, particularly the use of timestamps as a tiebreaker, to reduce incentives for strategic virtual bidding and incentivize participants to submit more accurate, cost-reflective offers closer to the operating day.

- *Allow Option For Real-Time-Specific Offer Schedules to Automatically be Used in Real-Time Energy Dispatch, in Support of Low Marginal Cost [Renewable] Resources*
  Wind and solar resources must offer into the day-ahead market but face uncertainty in real-time output. To manage this, they often submit higher day-ahead prices to reflect volumetric risk and lower real-time prices based on their low marginal costs. However, ISO-NE's system automatically carries day-ahead offers into real-time if a resource clears, requiring manual replacement by participants. In 2024, the IMM observed several cases where this manual process failed, leading to unnecessary down-dispatch of low-cost renewables. The IMM recommends ISO-NE allow separate day-ahead and real-time offers to prevent such issues, especially as renewable capacity grows.

Summary of IMM Market Enhancement Recommendations

One of the IMM's key functions is to recommend rule changes to enhance the performance of the markets. In practice, we communicate our recommendations through our reports, particularly our quarterly markets performance reports, and through comments filed with FERC on proposed rules changes.

The table below summarizes the IMM's recommended market enhancements, first showing issues with an "open" status, followed by recently closed issues. A hyperlink is provided to the document in which the recommendation was first put forward, along with the IMM's priority ranking of each recommendation. Recommendations included in this report for the first time are identified as "*NEW*".

The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well as the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, low priority recommendations are not intended to indicate low importance, but rather issues that may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

ID	Recommendation	When made	Status	Priority Ranking
2025-6	***NEW* Adopt a C&I Approach for Single-Year Capacity Offers Subject to IMM Review** Use a C&I approach for single year capacity offers subject to an IMM cost review. Eliminate the current Pivotal Supplier Test (PST) whereby only resources belonging to a pivotal supplier are subject to market power mitigation. The C&I framework is a more accurate measure of market power and avoids over- and under-mitigation risks associated with the current approach. Implement a Capacity and Impact (C&I) framework for evaluating single-year capacity offers that are subject to IMM cost reviews. Eliminate the existing Pivotal Supplier Test (PST), under which only resources belonging to pivotal suppliers are subject to market power mitigation. The C&I framework provides a more accurate assessment of market power and reduces the risks of both over-mitigation and under-mitigation associated with the current PST and Conduct approach.	2024 AMR	New Recommendation.	High
2025-5	***NEW* Review and clarify the time-out trigger for capacity resources to prevent inefficient transmission reservation** The current market rules state that a resource will be considered retired, and its interconnection rights terminated, if it does not "operate commercially" for three calendar years. The term "operate commercially" is not clearly defined, potentially allowing resources to retain interconnection rights by producing minimal energy output, even without plans to return to full operation. To prevent inefficient reservation of transmission capacity, the IMM recommends clarifying the Tariff to require that a resource demonstrates meaningful and sustained energy production to be considered commercially operational.	2024 AMR	New Recommendation.	Medium
2025-3	***NEW* Treatment of Export Transactions in Pay-for-Performance Settlements** The current Pay-for-Performance (PfP) rules create unequal incentives for imports and exports during scarcity events, crediting imports at the PfP rate but not applying a corresponding charge to all exports. While there is netting of imports and exports at the market participant level, this does not fully address the issue. This misalignment can lead to inefficiencies as it fails to prevent potential gaming opportunities, where related entities can profit from simultaneously scheduling imports and exports, receive credits for the import, and provide no reliability benefit.	2024 AMR	New Recommendation.	Medium
2025-2	****NEW* Provide Clarity on Need to Shed a CSO During Outage Periods*** The Tariff requires non-intermittent resources to offer their full CSO unless they are physically unavailable, but it lacks clear definitions and enforcement mechanisms for prolonged unavailability. The IMM considers a resource physically available if it is not on a forced or planned outage, consistent with other Tariff provisions and FERC rulings. However, resources can remain on outage and continue receiving capacity payments without being required to shed their CSO, which has led to enforcement actions in the past. Given the range of unavailability scenarios—such as early retirements, long-term outages, lack of fuel, or insufficient demand backing—the IMM recommends amending the Tariff to better define physical unavailability and to require resources to shed their CSO or face penalties if they cannot deliver capacity for extended periods.	2024 AMR	New Recommendation.	Medium

ID	Recommendation	When made	Status	Priority Ranking
2024-1	***Publish generation retirements that have occurred either prior to the effective retirement date in the FCM or outside of the FCM process*** Retirement timings do not always align with capacity commitment periods and early retirements remain outside of the publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants.	2023 AMR (May 2024)	ISO will evaluate this issue as part of the CAR project.	Medium
2023-2	**Review reserve pricing mechanics under fast-start pricing** Under current fast-start pricing rules, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium
2023-1	**Review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area** Market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generators supply offers. The IMM has identified a number of potential rule improvements to better serve the mitigation function. 1. Review of the current mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. 2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market. 3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas. 4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the "conduct test"). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels.	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium

ID	Recommendation	When made	Status	Priority Ranking
2022-1	**Incentive rebuttal component of proposed Buyer-side Mitigation Rules** The ISO's buyer-side mitigation rules will allow a Project Sponsor to demonstrate a lack of incentive through a Net Benefits Test to avoid mitigation of a below-cost supply offer from certain resources. The IMM has recommended that removing the incentive rebuttal provision from the proposal would make the buyer-side mitigation review more predictable and capable of being administered more reliably and with less subjectivity.	Filed Comments with FERC on MOPR Elimination and Buyer-side Mitigation Rules (Apr 2022)	Not in the scope of the ISO's current work plan.	Medium
2020-1	***Reference level flexibility for multi-stage generation*** Given that recommendation 2017-1 is not part of the ISO's work plan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	Winter 2020 QMR (May 2020)	Not in the scope of the ISO's current work plan.	Medium
2018-1	**Unoffered Winter Capacity in the FCM** The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g. monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.	Fall 2018 QMR (Mar 2019)	The IMM will evaluate this recommendation in the context of the ISO's planned revisions to its capacity accreditation methodology as part of the CAR project, which will separately account for summer and winter physical capabilities.	Medium
2017-1	***Treatment of multi-stage generation*** Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics. The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. Expanding the current pseudo-combined cycle (PCC) rules- Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes, or b. Adopt multi-configuration resource modeling	Fall 2017 QMR (Feb 2018)	Not in the scope of the ISO's current work plan.	Medium

ID	Recommendation	When made	Status	Priority Ranking
	capability- More dynamic approach to modeling operational constraints and costs of multiple configurations.			
2016-2	**Analyzing the effectiveness of Coordinated Transaction Scheduling** ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	2016 AMR (May 2017)	Related to 2016-1. Not in the scope of the ISO's current work plan.	Medium
2016-1	***Improving price forecasting for Coordinated Transaction Scheduling*** There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have been in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	2016 AMR (May 2017)	Not in the scope of the ISO's current work plan.	Medium
2015-3	**Pivotal supplier test calculations** The ISO, working in conjunction with the IMM, should enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	2015 AMR (May 2016)	IMM and ISO to assess the implementation requirements for this project. Not currently in ISO's work plan.	Medium
2015-1	***Corporate relationships among market participants*** The ISO should develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	Q2 2015 QMR (Oct 2015)	Not in the scope of the ISO's current work plan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium
2010-1	***NCPC charges to virtual transactions*** The ISO should develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.	2010 AMR (Jun 2011)	Not in the scope of the ISO's current work plan.	Medium

ID	Recommendation	When made	Status	Priority Ranking
2025-4	****NEW* Option for real-time-specific offer schedules to automatically be used in real-time energy dispatch, in support of renewable resources*** Wind and solar capacity resources must offer into the day-ahead market but face uncertainty in real-time output. To manage this risk, these resources often submit higher day-ahead prices to account for volumetric uncertainty, while offering lower prices in real-time to reflect their low marginal costs. However, ISO-NE's bidding system automatically carries day-ahead offers into real-time if a resource receives a day-ahead award, requiring manual action by the participant to overwrite the supply offers. The IMM has observed several cases in which the participant failed to take the manual overwrite action, leading to unnecessary downward dispatch of low-cost renewables in real-time. The IMM recommends ISO-NE enhance its systems to allow separate day-ahead and real-time offers to prevent such issues, especially as renewable capacity grows.	2024 AMR	New Recommendation.	Low
2025-1	****NEW* Clearing mechanics used at External Interfaces*** Participants have increasingly used virtual demand bids at the Highgate interface to secure real-time clearing priority for their imports. By pairing virtual demand bids with early-submitted import offers, participants can create counter-flow in the day-ahead market, enabling full clearing of their imports and gaining a timestamp advantage in real-time scheduling. While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time. To address this, we recommend that ISO-NE reevaluate clearing rules at non-CTS external interfaces, particularly the use of timestamps as a tiebreaker, to reduce incentives for strategic virtual bidding and allow participants to submit more accurate, cost-reflective offers closer to the operating day.	2024 AMR	New Recommendation.	Low
2024-2	**Establish an automated process to ensure transmission-constrained resources are not designated for reserves** Resources in New England are not eligible to provide operating reserves if constrained by transmission limitations. In practice, this is achieved through a manual process performed by system operators. When a transmission constraint binds, operators are tasked with applying a 'reserve down' flag to resources limited by that constraint. ISO dispatch software will not designate reserves on units that have the reserve down flag applied. This reflects the fact that, due to the transmission constraint, the reserves that would normally be counted on such resources are not deliverable to the system as energy. While market impacts related to this manual process not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints.	2023 AMR (May 2024)	Not in the scope of the ISO's current work plan.	Low
2021-1	**Develop Offer Review Trigger Price (ORTP) for co-located solar/battery facilities** Under the current rules, the ORTP for a co-located battery and	Filed Comments with FERC on	Closed: This issue is moot with the elimination of	Low

ID	Recommendation	When made	Status	Priority Ranking
	solar project is based on the weighted average of the individual technologies. This results in a value that is below the true "missing money" for the combined resource, allowing such resources to offer in at prices below competitive levels without review and mitigation, and undermining the protections put in place by the minimum offer price rule (MOPR). In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.	ORTP Recalculation (Apr 2021	MOPR and will drop off this list of recommendations.	
2013-1	**Limited energy generator rules** The ISO should modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	2023 AMR (May 2024)	Not in the scope of the ISO's current work plan.	Low

Section 1
Overall Market Conditions

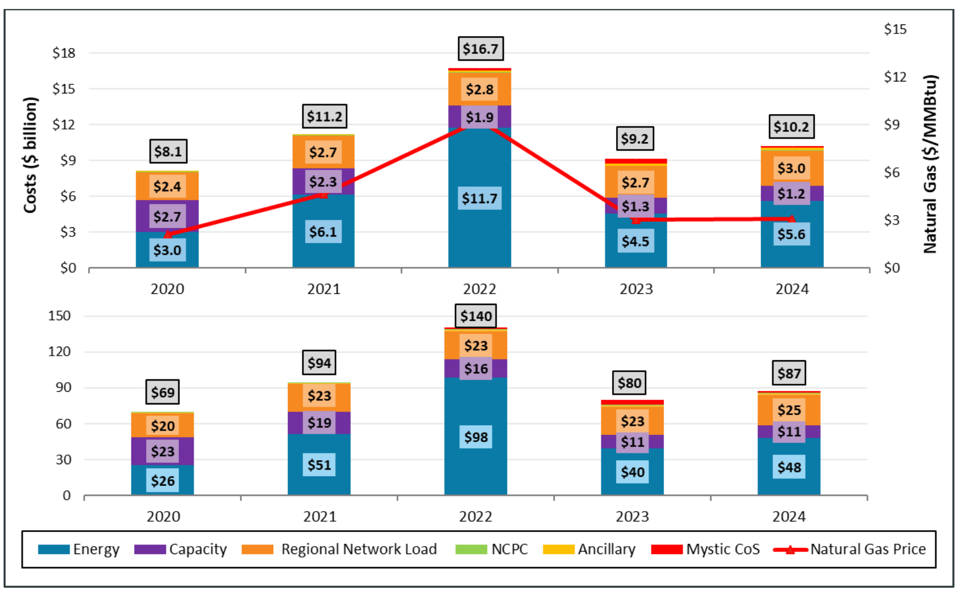
This section provides an overview of key trends in the wholesale markets. It covers the underlying supply and demand conditions behind those trends and provides important context for the more detailed discussions on market outcomes and performance in later sections of this report.

1.1 Wholesale Cost of Electricity

> ***Key Takeaways***
>
> Wholesale market costs totaled $10.2 billion in 2024, an increase of 11% (or $1 billion) compared to 2023. The increase was primarily driven by higher energy costs, which rose to $5.6 billion—an increase of 24% (or $1.1 billion) year-over-year.
>
> Higher energy costs were largely attributed to increased production costs and changes in the regional supply mix. Specifically, higher CO_2 emissions costs under the Regional Greenhouse Gas Initiative (RGGI) program and lower imports from Quebec were two key contributors. By contrast, natural gas prices—the primary driver of electricity prices in New England—remained relatively stable, averaging $3.06/MMBtu in 2024, similar to 2023 levels.

Figure 1-1 below gives an overview of wholesale electricity costs and average natural gas prices over the past five years, including significant changes in each cost category.

Figure 1-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs accounted for over half (55%) of wholesale electricity costs in 2024. Total energy costs of $5.6 billion increased 24% from 2023 costs but were significantly lower than the sixteen-year high in 2022 ($11.7 billion).[13] Although average natural gas prices in 2024 ($3.06/MMBtu) were comparable to 2023, energy costs increased due to higher CO_2 emissions costs and fewer net imports.[14]

Regional network load (RNL) costs, or transmission costs, include the costs associated with transmission infrastructure operation, maintenance, and investment borne by the transmission owners that have turned over their facilities for pool use as well as certain reliability and administrative costs.[15] RNL costs in 2024 were $3.0 billion, representing nearly 30% of total wholesale costs and a $300 million increase over 2023 costs.[16] Transmission costs are recovered based on monthly peak demand through the regional network service (RNS) rate, which rose from $141.64/kW-year in 2023 to $154.35/kW-year in 2024.[17]

Transmission costs in New England have increased in recent years as transmission owners have made investments to respond to reliability needs identified by the ISO as well as to replace aging transmission equipment within their local systems (known as "Asset Condition" projects). Notable projects undertaken by transmission owners to improve greater system reliability that were placed in-service in 2024 included work done to increase the load serving capability of greater Boston as well as to resolve thermal overloads in Maine.[18] Numerous asset condition projects across New England also went in-service in 2024. More generally, the cost of transmission projects has been impacted in recent years by economy-wide and sector-specific inflation, the latter coming as a result of heightened demand for transmission equipment as

[13] Energy costs in 2022 were the highest since 2008, due to significant increases in natural gas prices. Natural gas prices were driven by a combination of market conditions and events at an international and national level, in addition to regional New England winter issues. These factors included the Russian-Ukrainian conflict and the significant uptick in international demand for Liquefied Natural Gas (LNG), higher US demand and periods of sustained cold weather in New England. See IMM's *2022 Annual Markets Report* (June 5, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

[14] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, Tennessee gas pipeline Z6-200L, Tennessee North gas, Tennessee South gas, and Maritimes and Northeast. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 10 on D+2.

[15] The reliability costs include costs associated with resources retained for reliability (RFR) in the Forward Capacity Market (FCM), voltage support, high-voltage control, and system restoration. The administrative costs include local and system level dispatch and control costs as well as the budget for the New England States Committee on Electricity. For more information on these costs, see the ISO's *Monthly Regional Network Load Cost Report December 2024* (February 14, 2025), available at https://www.iso-ne.com/static-assets/documents/100020/2024_12_nlcr_final.pdf.

[16] The annual figure is the sum of the monthly Total RNL Costs as reported in the ISO's *Monthly Regional Network Load Cost Reports*, available at https://www.iso-ne.com/markets-operations/market-performance/load-costs/

[17] RNS rates are established using a prescribed methodology and then shared with FERC via an informational filing. More information about the determination of the 2024 RNS rate can be found in the *RNS Rate Effective January 1, 2024* presentation available at: https://www.iso-ne.com/static-assets/documents/2023/07/a03_1_pto_ac_notification_of_rns_rates.pdf

[18] For more information about the transmission projects that went into service in 2024, see the ISO's *RSP Project List and Asset Condition List* presentations, available at https://www.iso-ne.com/static-assets/documents/100013/final_project_list_presentation_june_2024.pdf and to https://www.iso-ne.com/static-assets/documents/100017/final_project_list_presentation_oct_2024.pdf. These presentations are updated three times per year.

power systems across the world experience increased electrification as part of the energy transition.[19]

Capacity costs comprise payments to supply resources in the Forward Capacity Market, accounting for 12% of wholesale costs in 2024, down 5% from 2023. Capacity clearing prices fell in 2024 relative to prior years, with prices of $2.00/kW-month in the fourteenth capacity commitment period (CCP 14) (January-May 2024) and $2.61/kW-month in CCP 15 (includes June-December 2024). While an increase in the net installed capacity requirement drove higher prices in FCA 15 (33,270 MW, up from 32,490 in FCA 14), capacity prices remained low relative to historic levels. Surplus capacity remained above 1,300 MW in FCAs 14 and 15 as new entry outpaced retirements.

Ancillary service costs include payments to supply resources for providing operating reserves and regulation services, and the costs of the Inventoried Energy Program (IEP).[20] Ancillary service costs totaled $176 million in 2024, up $12 million (7%) on 2023 costs due to higher IEP costs.[21] Lower net forward reserve costs offset some of the higher IEP costs. Net forward reserve costs were down by $38 million on 2023 due to lower clearing prices resulting from increased supply in the Winter 2024-2025 FRM auction, and lower requirements in the Summer 2024 auction.

Net Commitment Period Compensation (NCPC) costs, or uplift, covers supply resource production costs not recovered through energy prices. NCPC totaled $35 million in 2024, similar to the 2023 value, and comprised a small component of total energy costs at 0.6%. First contingency or "economic" payments made up 91% of total NCPC payments, a comparable share to 2023. Real-time uplift payments to units committed in economic merit order to meet load and reserve requirements continued to drive the majority of NCPC payments.

Mystic Cost-of-Service Agreement Payments: In early 2019, the Mystic 8 and 9 generators sought to retire through the capacity market but were retained by the ISO due to fuel-security concerns impacting power system reliability. From June 2022 through May 2024, the generators received supplemental payments to offset operating costs per their cost-of-service agreement (Mystic CoS).[22] These payments totaled $139 million in 2024, about 1% of total wholesale costs.

1.2 Fuel and Emissions Costs

Fuel and emissions costs are major drivers of electricity prices. While emissions allowance prices are a smaller share of electricity production costs for fossil fuel-fired generators, CO_2 costs have been increasing and comprised a larger share of production costs in 2024.

[19] The International Energy Agency noted that global prices for cables nearly doubled in real terms between 2018 and 2024, while power transformer prices increased by close to 75%. IEA (2025), Building the Future Transmission Grid, IEA, Paris https://www.iea.org/reports/building-the-future-transmission-grid, License: CC BY 4.0.

[20] The ancillary services total presented here does not include blackstart and voltage costs. Those costs are included in the RNL category.

[21] IEP costs increased because 2024 was the first year where three winter months (January, February, and December) of costs were included in the total; the program began in December 2023.

[22] Under the Mystic CoS, Mystic 8 and 9 have an Annual Fixed Revenue Requirement (AFRR), which is the amount they need to recover their operating costs for the commitment period. Capacity Supply Obligation (CSO) payments are not enough to cover the AFRR, and the supplemental payments fill the gap. Any additional revenues they receive are netted so revenues are capped at the AFRR.

Key Takeaways

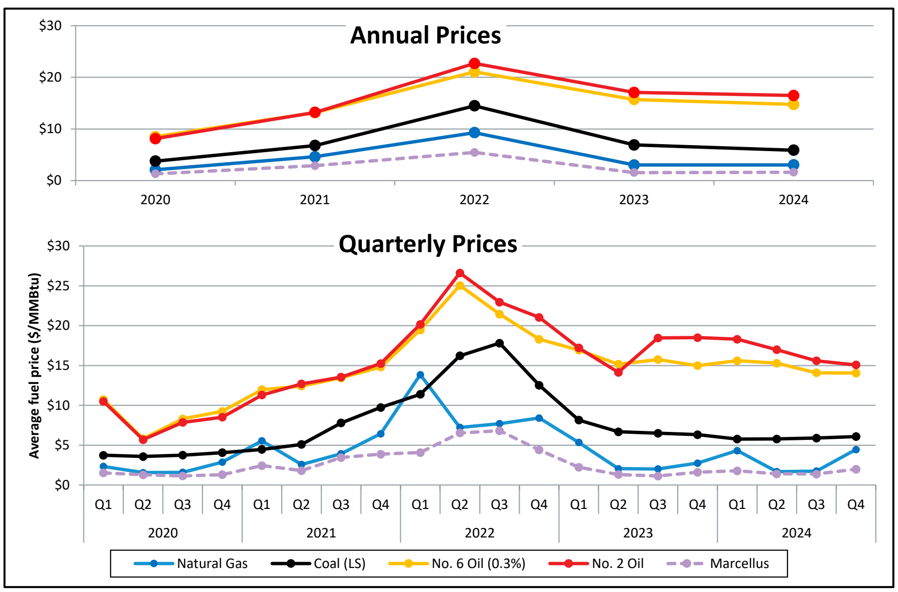
Annual average fuel prices remained relatively stable year-over-year in 2024. While natural gas prices were elevated during the winter, they declined across the other seasons due to high national natural gas supplies. In the context of lower gas prices and reduced imports, natural gas generation increased throughout 2024.

Carbon allowance costs also made up a larger share of total fossil fuel generation costs compared to prior years, driven by rising prices under the Regional Greenhouse Gas Initiative (RGGI). CO_2 costs represented a significant portion of production costs—ranging from 11% for oil-fired generation to approximately 30% for natural gas generation. CO_2 emissions costs were therefore a notable driver of energy prices; We estimate that carbon programs contributed approximately \$8/MWh to the average annual load-weighted energy price and added about \$910 million to total energy costs.

1.2.1 Fuel Costs

The annual and quarterly trends in fuel prices are shown in Figure 1-2 below.

Figure 1-2: Average Fuel Prices by Quarter and Year



Natural Gas

Annual average gas prices were just over \$3/MMBtu in 2024, remaining at similar levels to 2023. New England natural gas prices fell below \$2/MMBtu for the first time since 2020 in the non-winter quarters of 2024, while elevated prices occurred in winter quarters as a result of limited gas pipeline capacity. In warm periods, New England gas prices tracked historically low Henry hub prices driven by high natural gas storage levels.[23] Lower natural gas prices

[23] See EIA report *Spot Henry Hub natural gas prices hit a historic low in 2024* (January 8, 2025), available at https://www.eia.gov/todayinenergy/detail.php?id=64184.

contributed to high gas generator utilization rates (see section 3.2.2) and relatively low LMPs outside of winter months. While Henry and Marcellus hub natural gas prices remained low, at times, New England gas prices rose above hub prices even in relatively mild winter conditions. Quarter 1 and Quarter 4 gas prices averaged over $4/MMBtu, more than $2/MMBtu over hub prices during the winter. Daily gas prices exceeded $10/MMBtu on 22 days in the January and December 2024.

The EIA forecasts increasing gas prices over the next few years, with Henry hub natural gas price projections at $3.10/MMBtu in 2025 and $4.00/MMBtu in 2026.[24] Demand growth, primarily driven by LNG exports, is expected to outpace supply growth. Future New England prices will likely continue to reflect both hub prices and winter pipeline constraints, with increasing emission prices further contributing to gas generation costs.

Oil

No. 2 oil prices averaged $16/MMBtu and No. 6 oil prices averaged $15/MMBtu in 2024, both down marginally from 2023. Oil prices fell from highs in 2022 as global markets stabilized following the Russian invasion of Ukraine.[25] Oil generation comprised only a small fraction of total generation in 2024 as relatively inexpensive natural gas generation frequently set price and more expensive oil units typically ran during cold winter periods.

1.2.2 Emission Costs

New England Carbon Emissions Programs

New England's carbon programs, the Regional Greenhouse Gas Initiative (RGGI) and the Massachusetts Electricity Generator Emission Limits (MA EGEL), are designed to reduce greenhouse gas emissions by directly pricing CO_2 emissions. RGGI creates a unified carbon market across the Northeast, incorporating all New England states as well as additional states including Delaware, Maryland, and New York., while MA EGEL imposes additional emissions constraints on Massachusetts generators.[26] These frameworks influence generator operating costs and wholesale electricity prices by making the cost of carbon an integral factor in generation decisions.

At the heart of these programs is the cap-and-trade mechanism in which a limit (or cap) is set on total emissions, and generators must hold permits for each ton of CO_2 they emit. The cap is ratcheted down each year in line with carbon reduction goals. These permits are distributed through competitive auctions, allowing the market to establish a transparent, real-time value for pollution. As fossil fuel-based generators face higher costs under these systems, they are incentivized to invest in cleaner technologies and more efficient operations. In addition, auction revenues are strategically reinvested into initiatives that support energy efficiency (EE) and renewable generation.

[24] See EIA report *EIA expects higher wholesale U.S. natural gas prices as demand increases* (January 23, 2025), available at https://www.eia.gov/todayinenergy/detail.php?id=64344.

[25] See EIA report *Brent crude oil prices averaged $19 per barrel less in 2023 than 2022* (January 2, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=61142

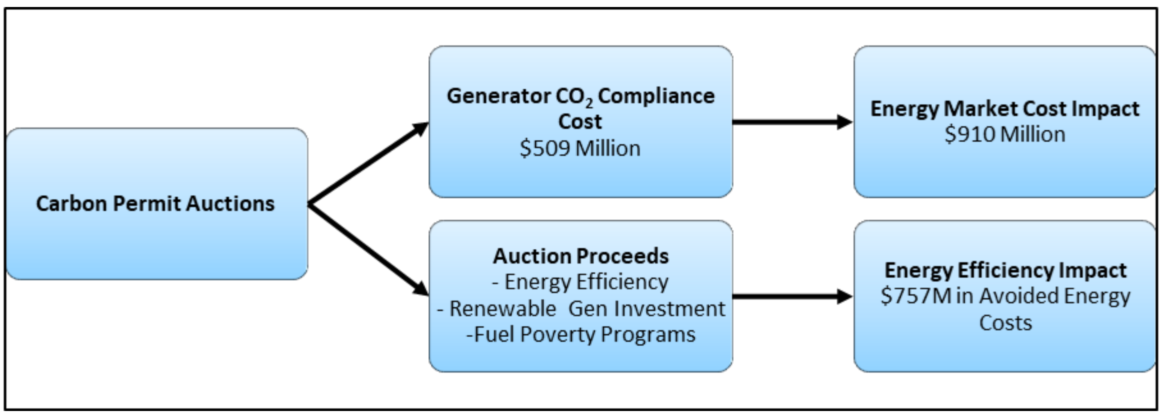
[26] See the Massachusetts Department of Environmental Protection's page *Electricity Generator Emissions Limits (310 CMR 7.74),* available at https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

Estimation of CO_2 Emission Programs Impact on LMP and Other Market Outcomes

In 2024, carbon allowance costs accounted for a larger share of total fossil fuel generation costs than in prior years. To evaluate their impact on energy prices, we simulated the day-ahead energy market and estimated that CO_2 programs added approximately $8/MWh to the average annual energy price on a load-weighted basis—representing 18% of the $44/MWh average LMP. In total, these programs contributed just over $910 million to wholesale energy costs, or 19% of the $5.6 billion annual total.[27]

In Figure 1-3 below, we summarize at a high-level the flow of carbon program funds from the auctions to energy initiatives and the impacts on wholesale market costs.[28] In 2024, the total cost for carbon compliance, based on spot prices for allowances, was $509 million.[29] The total cost of carbon allowances is lower than the total cost to the energy market because when fossil fuel-fired generators are on the margin, the inclusion of carbon costs raises the market clearing price — affecting all cleared megawatt-hours, even from those resources that do not require carbon allowances, e.g., renewable generators, nuclear generation and imports.

Figure 1-3: Carbon Program High Level Flow Chart



While the gross energy market impact is significantly higher than the total cost of compliance for generators, the energy market net cost of these carbon programs is significantly lower because the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs and clean and renewable energy. For example, the majority of auction proceeds from RGGI are invested by the New England States in energy efficiency programs.[30] These energy efficiency programs saved approximately 17.5 TWh in energy, or roughly $757 million in wholesale energy market costs based the 2024 LMP (See

[27] The simulation study compared two cases; the first based on actual supply offers and the second with the daily price of CO_2 emissions for both RGGI and MA EGEL programs subtracted from supply offers.
[28] This high-level conceptual flow chart is provided as a visual aid and is not intended to depict the precise uses of auction proceeds or the full funding mechanisms for energy efficiency (EE) programs, which are typically funded in part through retail electricity charges.
[29] The value of emissions is estimated using reported daily emissions data for New England generators for 2024 sourced from the EPA together with daily prices for RGGI and/or MA EGEL from an external vendor. See the EPA's *Clean Air Markets Program Data*, available at https://campd.epa.gov/data
[30] See RGGI's *Investments of Proceeds* reports, available at https://www.rggi.org/investments/proceeds-investments#:~:text=The%20RGGI%20states%20issue%20CO,strategic%20energy%20and%20consumer%20programs

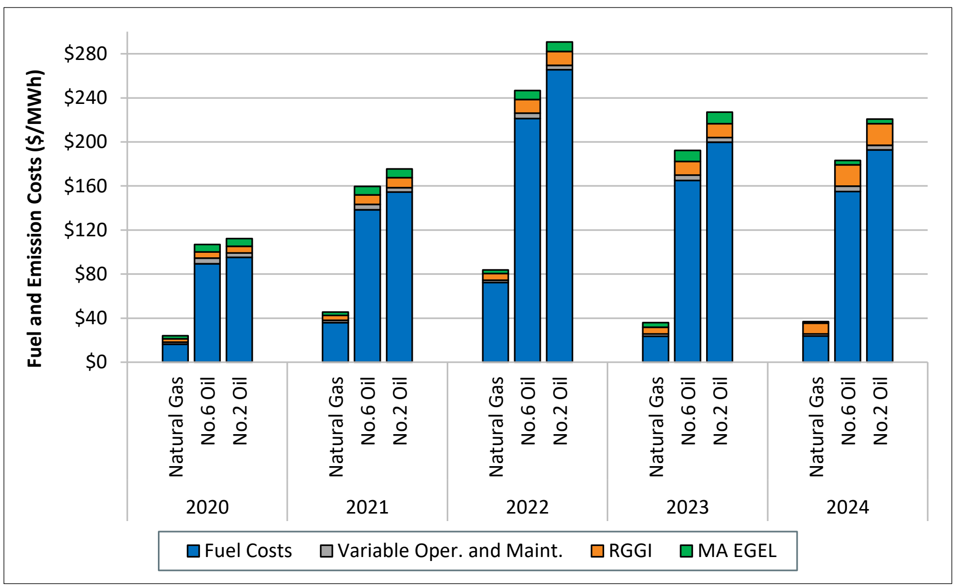
Section 1.5). Similarly, most proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions. [31]

In addition to price impacts, CO_2 costs can also influence dispatch patterns, and our simulation results showed modest changes to the day-ahead generation mix. Without carbon pricing, there is a slight reduction in imports into New England in response to lower energy prices and the simulation showed a slight increase in natural gas generation and oil generation particularly during cold winter periods when natural gas and oil price converge. [32] However, these effects are muted, as combined-cycle natural gas units remain the dominant balancing resource, and production cost differences among these units are relatively small. As a result, carbon pricing tends to result in a parallel shift in the supply curve—raising prices across the board—rather than causing substantial changes to the dispatch order.

Impact of Carbon Emissions Programs on Generator Operating Costs[33]

Our estimates of the annual average cost of emissions compliance by generator fuel type for both carbon programs are illustrated in Figure 1-4 below.

Figure 1-4: Annual Estimated Average Costs of Generation and Emissions[34]



In 2024, as fuel-related costs remained relatively stable year-over-year, emissions compliance costs accounted for a larger share of total generation costs, driven by a 55% increase in RGGI prices compared to 2023. RGGI costs added $9.59/MWh to production costs of an average natural gas combined cycle. By contrast, compliance costs under the Massachusetts EGEL

[31] See *310 CMR 7.74 Public Hearing Draft to Final Redline, Allowance Auction Procedures (6.h.1.i.),* available at https://www.mass.gov/doc/310-cmr-774-amendments-to-electricity-generator-emissions-limits-0/download

[32] The simulation did not remove CO_2 costs from New York, which also participates in RGGI.

[33] Fuel, CO_2 emission, and variable operating and maintenance costs are considered when calculating the costs for each generator. Variable operating and maintenance costs represent a small percentage of costs for generators. CO_2 prices in $/short ton are converted to estimated $/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel.

[34] IMM standard generator heat rates and fuel emission rates are used to convert $/ton CO_2 prices to $/MWh generation costs. The RGGI adder for a coal generator is about $22/MWh. Due to little remaining capacity, it is no longer shown in these exhibits.

program declined sharply—dropping 61% to $1.62/MWh for a combined cycle unit—helping to offset some of the impact from higher RGGI prices.

The drivers of the increase in RGGI costs are discussed in Section 3.2.1; in short, these include uncertainty regarding future emission limits to be determined in the ongoing third program review, continued reduced allowances, participation of financial investors, and the depletion of the cost containment reserve in early 2024.

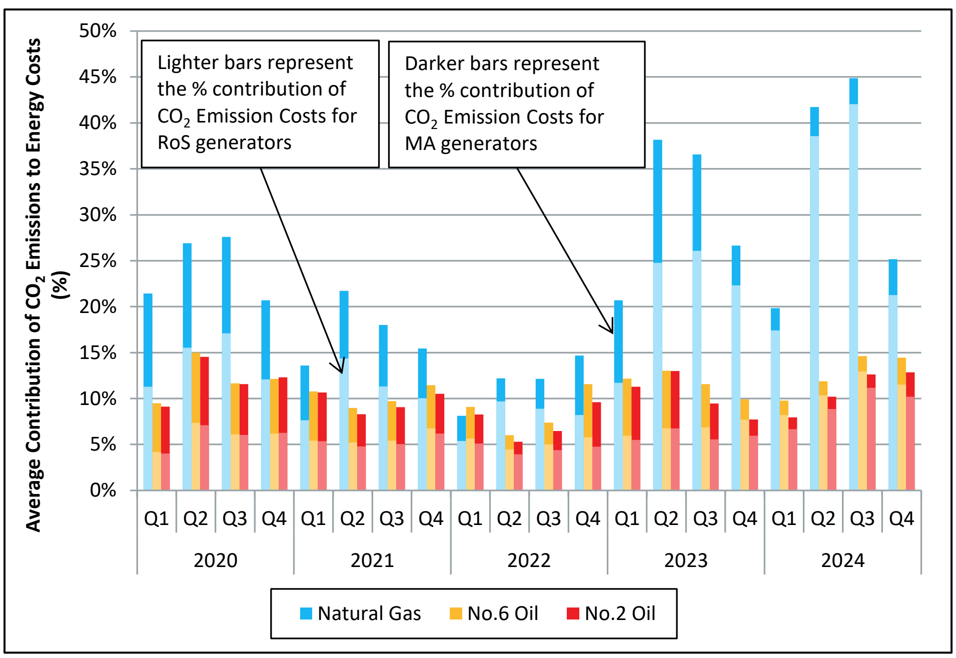
From 2023 to 2024, CO_2 emission costs for natural gas generators increased from $6.19/MWh to $9.59/MWh for RGGI participants and from $10.32/MWh to $11.21/MWh for Massachusetts generators. Table 1-1 below shows the impact of carbon programs on generation costs in 2024.

Table 1-1: 2024 Estimated Average Costs of Emissions and Percent Contribution of Generation Costs

Fuel Type	RGGI Costs ($/MWh)	MA EGEL Costs ($/MWh)	RGGI % of Generation Costs	Total CO_2 % of Generation Costs
Natural Gas	$9.59	$1.62	27%	30%
No. 6 Oil	$19.20	$3.96	11%	13%
No. 2 Oil	$19.80	$4.08	9%	11%

The contribution of CO_2 emission costs to energy production costs at a quarterly level is detailed in Figure 1-5.

Figure 1-5: Estimated Average Percent Contribution of CO_2 Emission Costs to Energy Production Costs



This graph highlights that during the second and third quarters of 2024, natural gas generators experienced the highest emission cost contributions, driven by significant increases in RGGI prices. Year-over-year, emission cost contributions increased 8% (from 19% to 27%) for natural gas generators participating only in RGGI, and just over 1% (from 29% to 30%) for generators in Massachusetts that were subject to both carbon programs.

1.3 Supply Conditions

Below, we present an overview of New England's generation and capacity mix by fuel type, location, and age. The composition of the system supply portfolio provides context to the relationship between fuel and wholesale prices, as well as emerging operational challenges.

Key Takeaways

Natural gas-fired generators, including dual-fuel units, remained the largest resource type in terms of both capacity and energy output in 2024. Natural gas resources accounted for roughly 60% of overall contracted capacity in the Forward Capacity Market (FCM) and provided approximately half of the electricity supply in the energy market.

Capacity: There was relatively little change in overall capacity composition during 2024. Natural gas generation capacity declined by approximately 700 MW on average, reflecting the retirement of the Mystic combined-cycle generators in May 2024. Nuclear and hydro resources comprised the next largest shares of contracted capacity, making up a combined 24% (12% each). Oil-fired generation accounted for 10% of contracted capacity. Solar, wind, and battery storage resource totaled 600 MW or just 6% of total supply capacity.

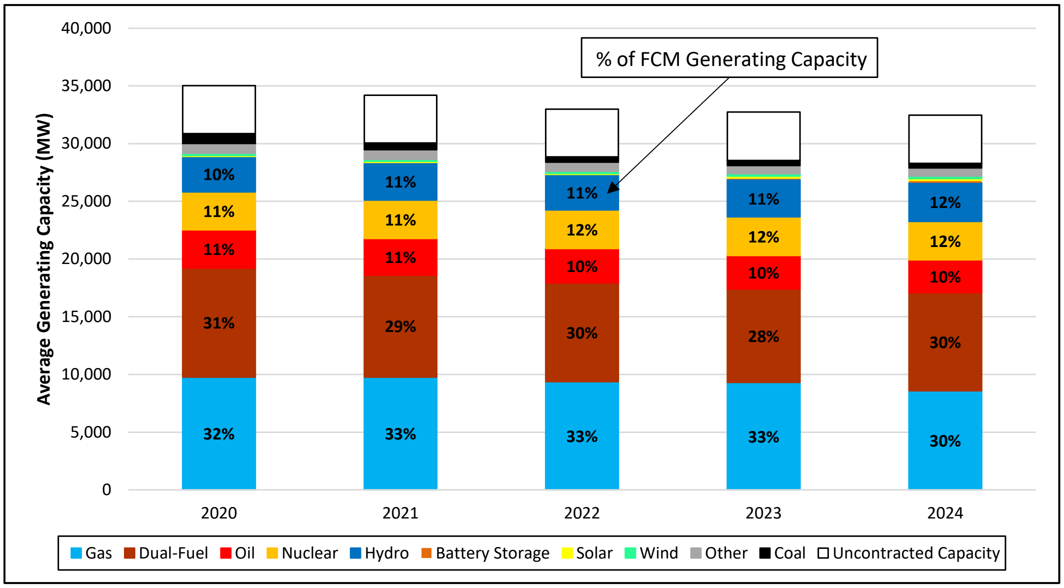
Approximately 4,000 MW of generation capacity does not participate in the FCM. Although not subject to the must-offer requirement applicable to FCM resources, this non-FCM capacity continues to provide important reliability support, particularly under stressed system conditions.

Energy: The share of energy produced by natural gas generation and nuclear generation combined rose from 68% to 72%. This increased reliance on natural gas generation (at 50%) stemmed from a reduction in net interchange from the Canadian provinces, which provided just 5% of New England's energy supply in 2024 compared to an average of 13% in prior years. This decrease was primarily driven by extended dry weather conditions in Canada, which limited hydroelectric generation. Overall, net interchange with Canadian and New York balancing areas combined was at its lowest level in thirteen years (since 2011).

Generation Capacity

Capacity by generator fuel type in Figure 1-6 below shows the breakdown of total capacity contracted in the FCM, as well as capacity without a capacity supply obligation.[35]

Figure 1-6: Average Capacity by Fuel Type[36]



Average generating capacity fell slightly in 2024 following generator retirements that offset new capacity additions. The five-year trend of decreasing capacity is consistent with a declining Net Installed Capacity Requirement (Net ICR). The capacity resource mix was relatively constant year-over-year. Contracted gas capacity fell 8% from 2023 following the Mystic Generation Station retirement in FCA 15 (2024/25). Dual-fuel capacity, 60% of which consists of combined-cycle generators, has remained stable over the past five years. Contracted renewable capacity increased steadily in 2024 as solar, wind, and battery storage capacity totaled 600 MW or 6% of total contracted capacity (28,000 MW). Roughly 4,000 MW of capacity was not contracted in the capacity markets in 2024, similar to prior years. Such uncontracted capacity can continue to operate in the energy and ancillary services markets and can provide important reliability benefits during stressed system conditions.

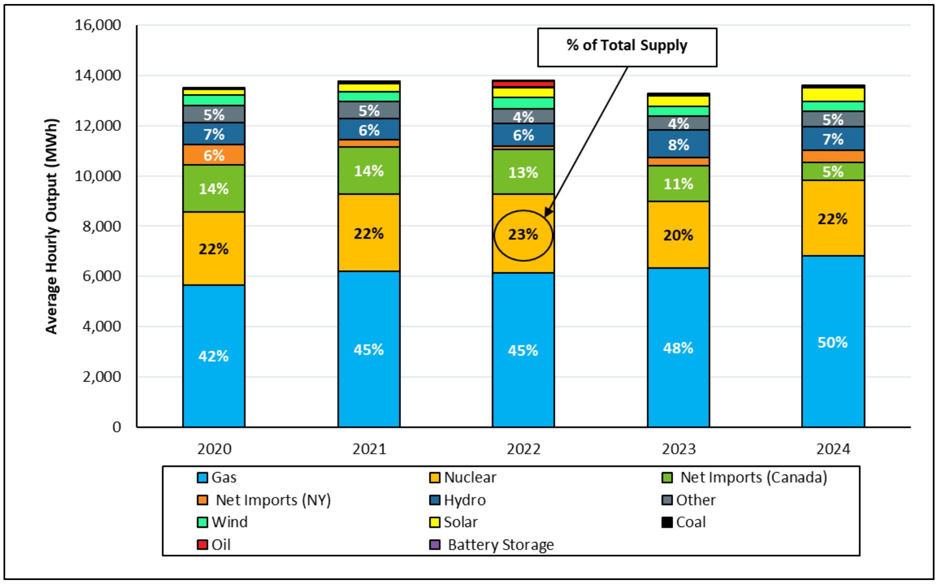
Energy Supply Mix

Energy production by fuel type is illustrated in Figure 1-7 below. The figure shows a breakdown of hourly average supply (MWh produced, averaged across all hours) by fuel type for generation internal to the New England control area, along with average net interchange with neighboring control areas.

[35] This figure shows generating capacity, which excludes imports and demand response units. We calculate "uncontracted capacity" as the total maximum net output of the generation fleet minus the total contracted capacity of the generation fleet.

[36] The "Coal" category includes generators capable of burning coal and dual-fuel generators capable of burning coal and oil. The "Other" category includes active capacity demand response, landfill gas, methane, refuse, steam, and wood.

Figure 1-7: Average Output and Share of Electricity Supply by Fuel Type



Natural gas generation accounted for half of all energy supply in 2024, more than twice the next largest fuel type, nuclear, which provided 22% of total energy supply on average. Each provided a larger share of energy than in the preceding year as a result of the decline in net imports from Canada, which are typically a key source of baseload supply, along with higher availability of both gas and nuclear generators (fewer planned and forced outages).

Net interchange from neighboring control areas provided the third largest share of energy supply, comprising 9%. This is the lowest share for this supply type across the study period and is the result of a significant drop in net imports from Canada. In prior years, net imports from Canada comprised, on average, 13% of supply; in 2024, they provided just 5%. As discussed in detail in Section 4.1.1., this level of net interchange with neighboring control areas is the lowest since 2011.

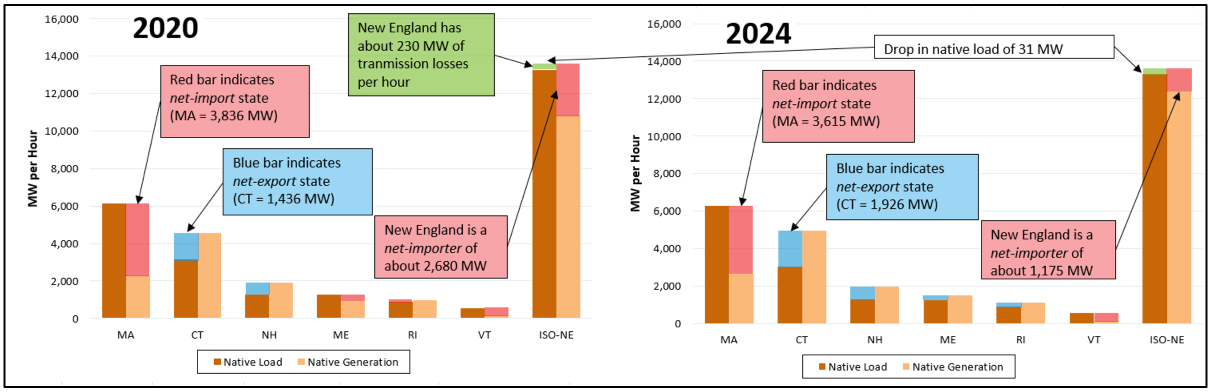
While their share of generation is small, solar and wind production remain a key focus of energy policies that will impact New England's energy landscape over the coming years. State and federal policies have driven additional wholesale (front-of-the-meter) solar energy production and wind energy production.[37] Solar and wind accounted for 4.8% of energy supply in 2020, and this share increased to 6.8% in 2024. Notably, these two supply types provided a larger share of energy supply than net imports from Canada in 2024.

[37] Section 3.3 discusses the impact of solar generation on load from both behind- and front-of-the-meter solar.

Generation and Consumption by State

A breakdown of energy production and consumption within each state and aggregated across the ISO-NE market is shown in Figure 1-8 below.[38] Darker shaded bars show state load, while lighter shaded bars show state generation. The red and blue bars simply show the difference between production and consumption; the red bars illustrate net imports into each state, and the blue bars net exports out of the state.[39,40]

Figure 1-8: Average Electricity Generation and Load by State[41]



Given their larger populations, Massachusetts and Connecticut are the largest consumers and producers of electricity within the six states, comprising 70% of the regions load on average. Connecticut remains a significant net exporter of energy, continuing the trend observed in prior years and aligning with the fact that Connecticut's annual average prices were approximately $1/MWh lower that the Hub prices during 2024 (see Section 3.1.1 for further details). Massachusetts, on the other hand, remains a significant importer of energy.

The total ISO-NE bar summarizes two key trends. First, average native load in New England was relatively static compared to 2020, indicating that expectations of significant future load growth due to increased electrification of the heating and transportation sectors have not yet materialized as of 2024.[42] Second, New England continues to be a net importer of power, although its reliance on imports fell significantly relative to 2020, by more than 1,500 MW (a decrease of more than 50%). This occurred primarily due to lower imports over the Phase II interface. More information on net imports can be found in Section 4.

Capacity Additions and Retirements

The supply mix in New England is evolving. As generators age, they require increased maintenance and upgrades to remain operational, thereby increasing their costs to operate.

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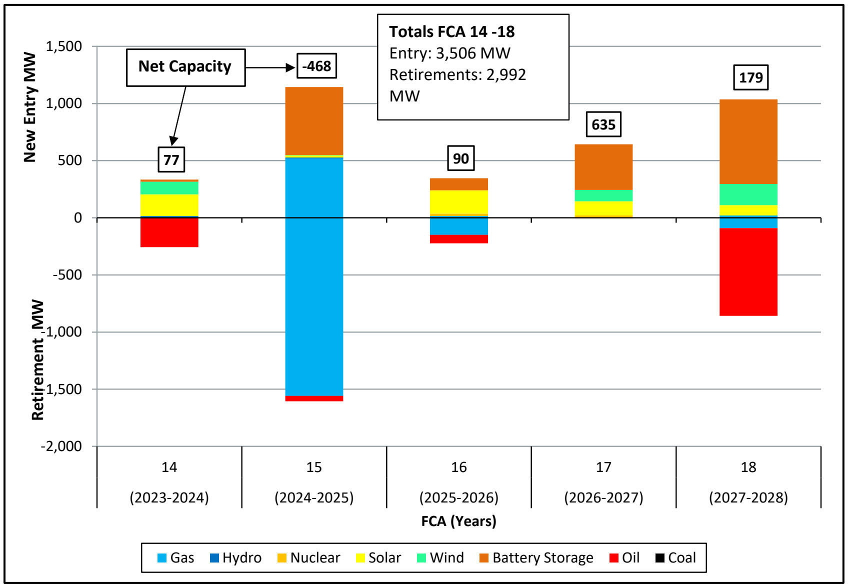
[38] The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions.
[39] The green bar for ISO-NE illustrates losses as energy flows through the system.
[40] Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada) but refer to any imports from outside the state.
[41] Note: MW values are rounded to the nearest 10 MW.
[42] See ISO's report *Economic Planning for the Clean Energy Transition* (October 24, 2024)

Older coal- and oil-fired generators in New England also face increasing compliance costs associated with public policies intended to reduce greenhouse gas emissions.

Generator additions and retirements in each Forward Capacity Auction (FCA), beginning with FCA 14 (CCP 2023/24) are shown in Figure 1-9 below. Outcomes through FCA 18 are shown since the ISO did not administer a forward auction for CCP 19 in 2024.[43] Net surplus capacity (new capacity minus retired capacity) is also displayed for each auction.

Figure 1-9: Generator Additions and Retirements



Wind, solar, and battery storage have accounted for over 80% of all new generating capacity that has cleared in the FCM for the capacity commitment periods from 2023/24 onward (i.e., since FCA 14). These technologies will comprise an increasing share of supply over the coming years, playing a significant role in meeting the states' decarbonization goals. However, while battery storage resources currently qualify in the FCM close to their nameplate capacity, their capacity value will likely fall significantly under the proposed new marginal accreditation methodology due to their lower contribution in the event of multi-hour unserved energy events.[44] There have been no significant additions to gas generation capacity in the past five auctions; the addition of gas capacity in FCA 15 mostly comprised a repowering project of the existing Ocean State combined cycle generator.

Most retirements include older oil-, and gas-fired generators. The largest retirements occurred during FCA 15 with the delayed retirement of over 1,400 MW of gas-fired generation at the Mystic station. Oil capacity retirements in FCA 18 were largely attributable to resources at the Middletown station in Connecticut.

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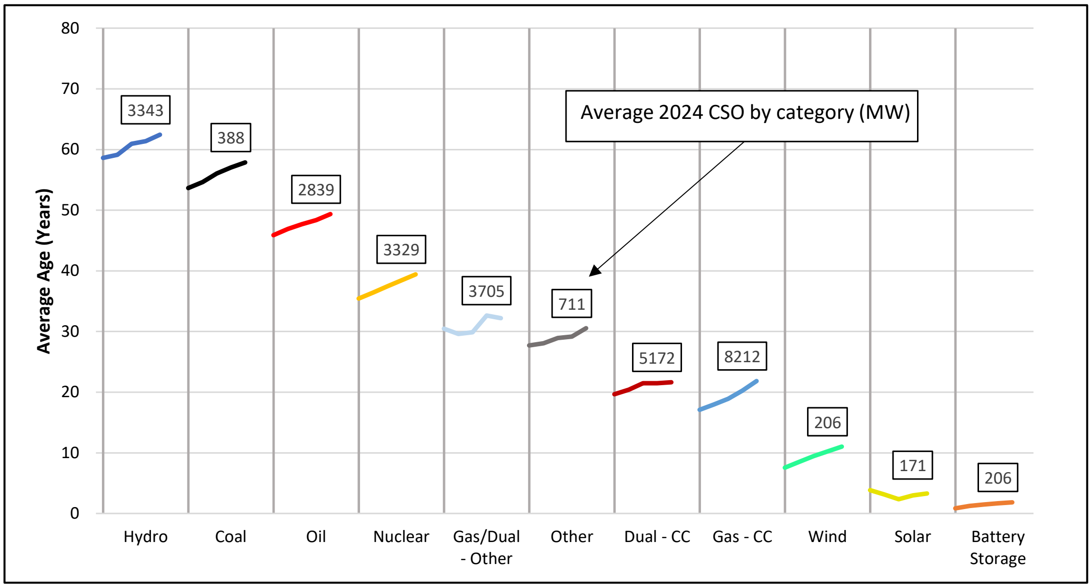
[43] Capacity auction changes, including the transition to a prompt rather than forward capacity auction, are included in the Capacity Auction Reforms (CAR) key project. For more information, see the ISO's *Capacity Auction Reforms Key Project* overview page, available at https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[44] See ISO's presentation, *Resource Capacity Accreditation in the Forward Capacity Market*, *FCA 18/19 Accreditation Sensitivity Analysis, Part 2,* by Dane Schiro (April 9-10, 2024), available at https://www.iso-ne.com/static-assets/documents/100010/a03d_mc_2024_04_09_10_impact_analysis_sensitivity_results.pdf

Average Age of Generators by Fuel Type

The average age of New England's generation fleet is illustrated in Figure 1-10, and provides some insight into how the supply mix is evolving and potential future challenges for the region.[45]

Figure 1-10: Average Age of New England Generator Capacity by Fuel Type (2020 - 2024)[46]



Hydro (average age of 62 years), coal, and oil (49 years) generators are among the oldest generator types in New England, with virtually no new resource entry in these categories. Oil-fired generators, in particular, face growing economic pressure to retire due to competition from lower-cost resources, increasing emissions costs, and higher maintenance expenses associated with aging infrastructure and infrequent dispatch. Despite these economic challenges, oil-fired generators continue to provide important reliability value—especially during winter periods when natural gas generation may be limited by pipeline constraints and renewable output is reduced.

The region's newer supply of generators includes relatively efficient gas and dual-fuel combined cycles generators (22 years) and an increasing share of renewable resources. New capacity additions are overwhelmingly renewable, with wind, solar, and battery storage capacity comprising the youngest generation types.

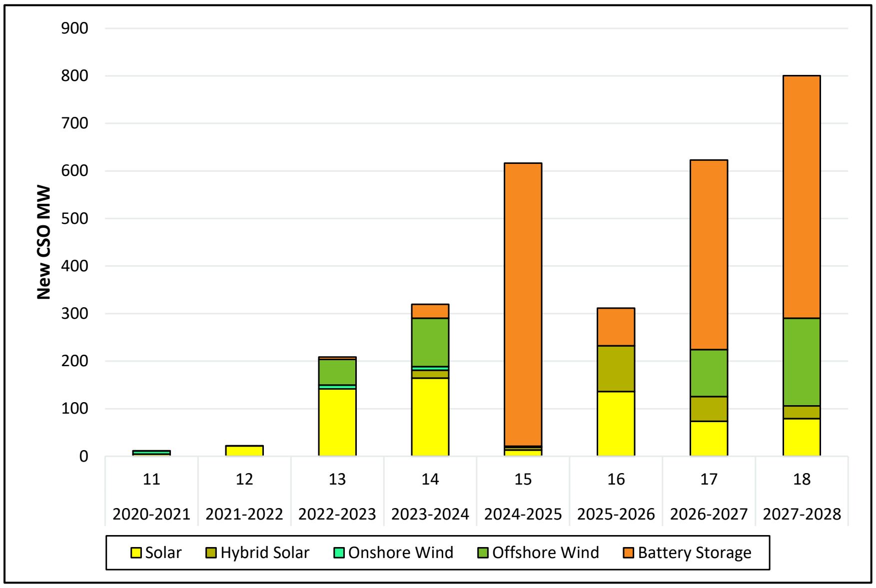
Renewable, Battery Storage, and Hybrid Capacity

Renewable and battery storage generators are among the most recent additions to the generation fleet, with new capacity projected to grow in the coming years. At present, solar,

[45] Age is determined based on the generator's first day of commercial operation. The average values are weighted by the max net output for each generator within the fuel type. If there were no retirements or new generation, we would expect each colored line to increase by one year as generators age. Either an influx of new generators or a retirement of old generators can cause a decline in average age. Data labels above the bars show average total FCM capacity in 2024 by fuel type.
[46] The "Other" category includes landfill gas, methane, refuse, steam, and wood.

wind and battery storage technologies make up close to 100% of ISO New England's nearly 44,000 MW interconnection queue.[47] Figure 1-11 below shows new capacity additions for these renewable fuel types by FCA commitment period. Solar facilities are separated into traditional and hybrid storage types.

Figure 1-11: New Renewable Capacity by Commitment Period



Solar, wind, and battery storage capacity accounted for roughly half of new generating capacity in FCA 16 and the following auctions. The vast majority of wind capacity additions were offshore, with over 100 MW of new cleared capacity in FCA 17 and 18. New battery storage capacity exceeded 500 MW in FCA 15 and made up the largest share of new generating capacity additions in FCAs 17 and 18. Hybrid solar facilities, which made up more than a quarter of total new solar capacity since FCA 15, utilize local energy storage to increase generation in hours following the solar peak when renewable generation is relatively scarce.

While Figure 1-6 shows generating capacity that cleared in forward auctions and Figure 1-11 shows new renewable capacity, the interconnection queue provides another view into upcoming capacity additions. The interconnection queue is overwhelmingly (>99%) composed of wind, solar, and battery resources.[48] As of January 2025, roughly 1,000 MW of wind capacity, 400 MW of solar, and 600 MW of battery storage appear likely to become operational within the next year and the interconnection queue contained over 14,000 MW of offshore wind.[49]

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[47] See *Continuing Enhancements to ISO New England's Generator Interconnection Processes* presentation, by Alex Rost, (October 28, 2024), available at https://www.iso-ne.com/static-assets/documents/100017/iso_ne_interconnection_workshop_october_2024_final.pdf

[48] See the ISO's *Resource Mix* report, available at https://www.iso-ne.com/about/key-stats/resource-mix.

[49] See the *January 2025 NEPOOL Participants Committee Report*, presented by ISO-NE COO Vamsi Chadalavada, available at https://www.iso-ne.com/static-assets/documents/100019/january-2025-coo-report.pdf.

1.4 Demand Conditions

This section covers trends and underlying drivers of historic and anticipated energy demand, including the impact of weather, energy efficiency, and behind-the-meter solar generation.

> ***Key Takeaways***
>
> Load levels rose slightly (2%) in 2024, averaging 13,294 per hour, from historically low levels in 2023. Behind-the-meter (BTM) solar and Energy Efficiency (EE) measures continue to contribute to load reductions, by an estimated 600 MW and 2,000 MW on an average hourly basis in 2024. Average load levels in New England have been stable over the past five years, with a variation of +/- 2% from the five-year average.
>
> Peak load reached 24,871 MW in 2024, well below the peak load forecast for CCP 15 (2024/25) of 29,000 MW. New England load growth has typically been below forecast, as uncertainty in electrification rates is a significant challenge for load forecasters. A shorter forecast window provides greater peak load forecast accuracy with respect to the pace of electrification and should allow for more cost-effective capacity procurements under a prompt capacity auction.

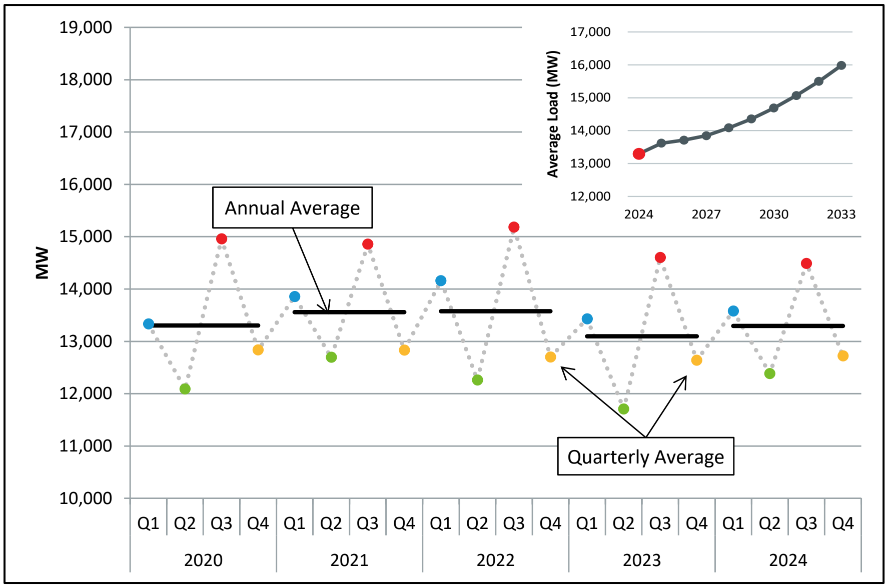
Wholesale Demand[50]

Wholesale demand rose slightly in 2024, from historically low levels in 2023. While load increased, average loads were below forecasted levels. Annual and quarterly average loads from 2020 to 2024 are shown in Figure 1-12 below, with an inset graph of projected load growth.[51]

[50] Wholesale electricity demand or Net Energy for Load (NEL) excludes both electricity demand that is met by behind-the-meter generation and asset-related demand for pumped-storage or battery-storage facilities.

[51] To view load forecasts through 2032, see the ISO's *2024-2033 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 17, 2024), available at https://www.iso-ne.com/system-planning/system-plans-studies/celt. Forecasted annual load in GWh is converted into average hourly MW values.

Figure 1-12: Average Hourly Load by Quarter and Year



Load averaged 13,294 MW on an hourly basis in 2024, up by 2% from 2023, while load peaked at 24,871 MW on July 16, 2024.

While load increased in 2024 relative to 2023, BTM and EE continued to reduce net load. BTM solar reduced loads by 600 MW on an average hourly basis. Estimated installed BTM capacity reached almost 5,000 MW by the end of the year, and BTM generation frequently performed at high capacity factors in mid-day periods. EE measures reduced load by an estimated 2,000 MW per hour. This EE estimate declined from 2023 and is projected to continue to fall due to claimable savings calculations and increasing costs of eligible EE measures. The implications that BTM solar and EE have on load and load curves are discussed in more detail in Section 1.5 below.

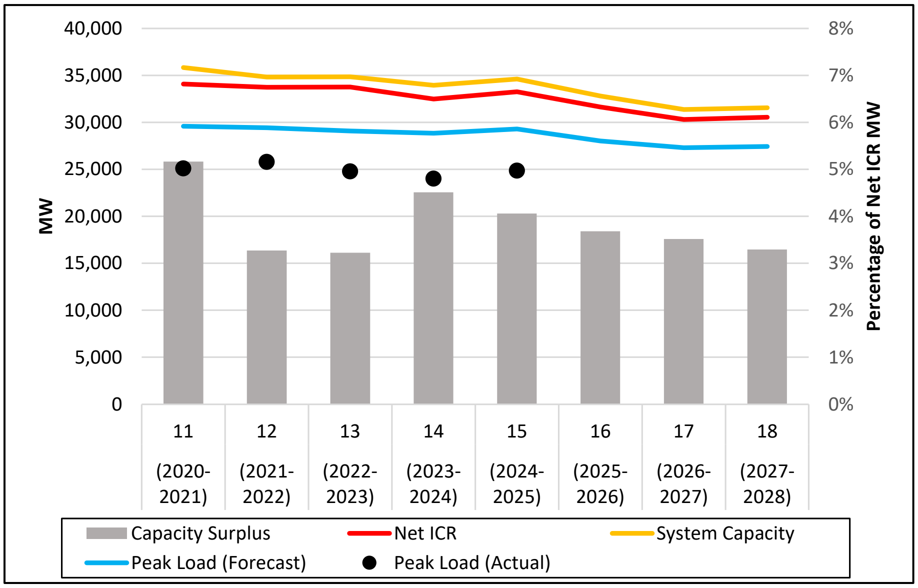
Capacity Market Requirements

The Net Installed Capacity Requirement (Net ICR) is the amount of capacity needed to meet the region's 1-in-10 year reliability standard.[52] The Net ICR value is used to anchor the administrative system demand curve for the FCA and is a significant determinant of auction clearing prices.

Trends in system capacity requirements (Net ICR, peak load forecast) and system capacity procurement (system capacity, capacity surplus) are shown in Figure 1-13 below. The Net ICR, peak load forecast, and system capacity are represented as line series aligned with the left axis. Capacity surplus as a percentage of Net ICR is represented as a bar series aligned with the right axis.

[52] The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than one day every ten years. When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a combination of variables such as anticipated demand of local consumers and anticipated supply from neighboring control areas.

Figure 1-13: NICR, Peak Load Forecast, and Capacity MW for FCA 11-18



Net ICR and peak load forecast have steadily declined since FCA 11 (2020/21).[53] FCM peak load forecasts have generally overestimated actual peak loads. For the FCA 15 delivery period (2024/25) the actual peak load was below 25,000 MW compared to a peak load projection of 29,000 MW used to determine NICR. Deviations between forecast and actual peak loads largely reflect uncertainty in the rate of electrification of the heating and transportation sectors.

Notably, the 2024 summer peak load forecast in the 2023 CELT report was close to actual peak load, with 24,633 MW forecast and 24,781 MW in actual peak load. A shorter forecast window provides greater peak load forecast accuracy with respect to the pace of electrification and should allow for more cost-effective capacity procurements under a prompt capacity auction.

1.5 The Evolving Demand and Supply Landscape in New England

The New England states continue to invest heavily in the power sector as a key strategy for achieving their decarbonization goals, including investments in energy efficiency (EE) measures, storage, and renewable supply at both the wholesale market and retail levels (behind-the-meter generation). Notable growth has occurred in solar generation, and offshore wind and energy storage capacity are also expected to increase significantly in the coming years.

The ISO's Economic Planning for the Clean Energy Transition (EPCET) study and the Analysis Group's Pathways study are two long-term, forward-looking assessments of a decarbonized grid in the context of significant load growth driven by heating and transport demand.[54,55] Both

[53] For Net ICR amounts and related values for all auctions see *ISO New England Forward Capacity Market - Summary of ICR and Related Values*, available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx. The 50-50 Summer Peak Load forecast appears in the above figure.

studies offer valuable insights into the operational and market implications of large-scale renewable integration, including effects on pricing, revenue streams, balancing resource utilization, and load and generation profiles.

In this section of the report (and elsewhere), we check in on trends across several metrics related to these implications. Unsurprisingly, given the current environment of relatively stable load and modest renewable generation growth (compared to what will be required for deep decarbonization), the impacts to date remain relatively muted. However, this assessment provides a useful framework for tracking developments in future updates.

Key Takeaways

High-Level Changes: Growth in the renewable energy sector has been led by solar at both the retail (behind-the-meter) and wholesale levels, helping to offset declines in energy efficiency (EE). From 2023 to 2024, the contribution of renewables to gross demand increased from 17.7% to 19.1%, though the wholesale share remained flat at 16%. Meanwhile, although residual wholesale load (load net of renewable generation) remained stable, a sharp 56% drop in net imports has led to a notable shift toward greater use of balancing resources.

Load Profiles and Ramps are Changing: While the overall impact of additional intermittent resources has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. BTM solar generation has significantly altered hourly load profiles, reducing morning wholesale load ramps while steepening evening ramps. Between 2020 and 2024, the evening ramp in residual wholesale load increased from 427 MW per hour to 712 MW per hour. Real-time energy prices now rise earlier in the morning, dip mid-morning with increased solar production, and climb sharply during the evening ramp as more expensive generation is dispatched to meet higher load levels.

Low Midday Loads: The wholesale demand "duck curve" has become a common occurrence over the last five years and with solar capacity projected to double over the next 10 years, it will increasingly present challenges for both markets and system operations. Historically, the lowest demand has occurred during the nighttime, but there has been a notable increase in the frequency of minimum residual wholesale load occurring later - between 8am and 3pm. The frequency has increased from 5% in 2020 to 38% in 2024.

Low wholesale loads levels are not resulting in over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower mid-day load, we have observed changes in flexible demand[56] shifting consumption from overnight to mid-day hours, albeit with a quite moderate load impact on an annual basis.

Supply Flexibility: As the grid transitions to include more intermittent generation, large changes in residual wholesale demand will place a premium on flexible, dispatchable generation. To date, we have not observed over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators

[56] Pumped and battery storage resources

curtailing supply and periods of negative energy prices. Between 2020 and 2024, there has not been a significant downward shift in margin between fixed supply and demand, and the number of ramp-constrained intervals has remained low.

Fast-start generation plays a more significant role in the relatively steep evening ramp period. While fast-start generation has been dispatched at an increasing rate in evening ramp periods, surplus fast-start capacity exists to meet growing ramps. Fast-start generation averaged less than 20% of offered capacity during evening ramps in 2024, and did not exceed 60% of offered capacity during ramping periods in any hour.

Load Forecasting: Load uncertainty and forecasting challenges are expected to increase, and ISO-NE has already invested in enhancing short- and long-term forecasting techniques, with continued improvements planned. Despite the growth in BTM solar generation, there has been no discernible deterioration in day-ahead load forecast accuracy. Long-term ISO-NE projects a 17% increase in average hourly load between 2023 and 2033, largely driven by the electrification of transportation and heating. Summer and winter peak loads are expected to rise by 10% and 26%, respectively, between 2025 and 2033, with additional uncertainty stemming from extreme weather conditions particularly during cold winter periods.

Attracting and maintaining sufficient balancing resources to meet expected but infrequent surges in winter demand will be critical.

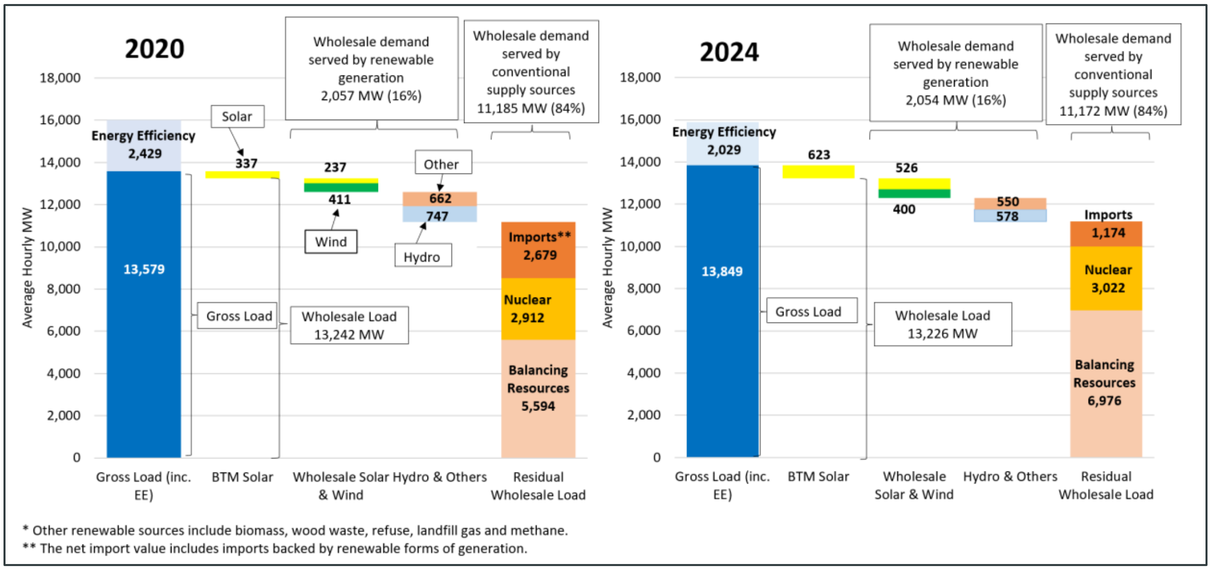
Figure 1-15 below provides a five-year snapshot of changes in the region's electricity demand, the contribution of energy efficiency (EE) to reducing energy demand, and the forms of generation that serve both gross demand (a proxy for retail demand) and wholesale demand.[57, 58, 59]

[57] Demand is weather-normalized to allow for a clearer comparison. Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[58] Energy Efficiency is based on aggregated performance of installed measures on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment. Energy Efficiency and Demand Response Distributed Generation (DG) measures are aggregated to On-Peak and Seasonal-Peak resources. Performance of DG accounts for only 5% of energy efficiency performance.

[59] Behind-the-meter solar production and energy efficiency estimates are provided by ISO New England's system planning department.

Figure 1-14: A Five-Year Snapshot of Demand and Supply, 2020 vs. 2024



The most significant growth in the renewable energy sector has occurred in solar, at both the retail and wholesale levels, helping to offset declines in EE. While EE has played a major role in reducing system load over the past decade, its growth has plateaued in recent years due to rising costs of eligible measures and changes to EE baselines used to calculate claimable savings.

Overall, the contribution of renewables to meeting gross demand increased from 17.7% to 19.1%. However, at the wholesale level, the share remained flat at 16%, as higher solar output was offset by reduced hydroelectric generation due to drought conditions and a decline in other renewable sources. Looking ahead, the commissioning of major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704 MW), and the New England Clean Energy Connect (1,200 MW) transmission line—will significantly expand the region's renewable energy portfolio over the coming years.[60]

Finally, demand met by remaining supply technologies—referred to as Residual Wholesale Load—has remained relatively unchanged in recent years. However, the composition of supply meeting this residual demand shifted significantly in 2024. Notably, the contribution of net imports declined by approximately 56% in the five-year period, leading to an increase of roughly 1,400 MW per hour in non-renewable dispatchable generation, referred to as Balancing Resources in the figure.

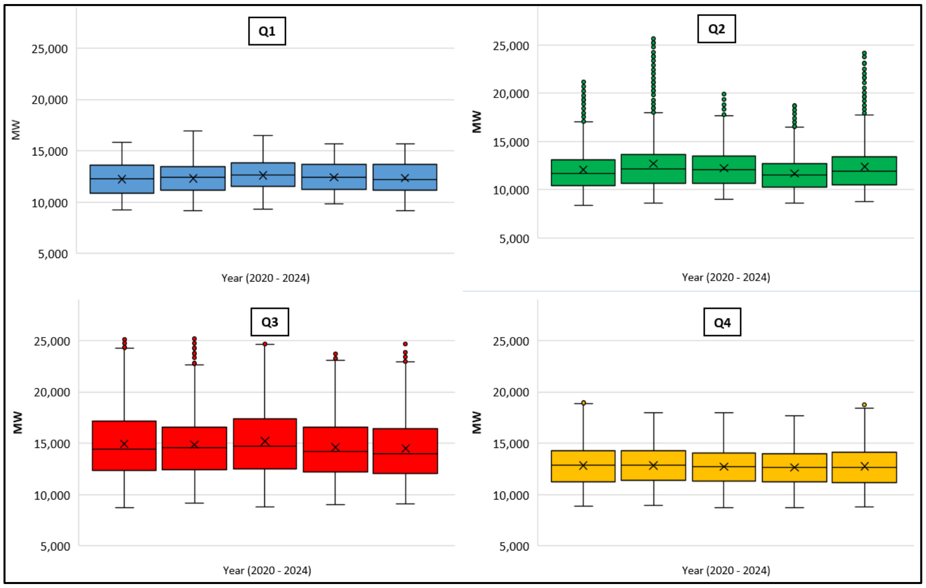
1.5.1 Quarterly Wholesale Loads

Variability in annual average and peak loads is expected to increase significantly in future years particularly driven by heating demand for electricity during the winter and the sensitivity of demand to winter temperatures. Further, with the growth of BTM solar generation, challenging minimum load conditions may occur which could lead to curtailed supply. While current load profiles already show significant day-to-day and intraday variability due to BTM solar output, a clear trend of increased variation at the annual or quarterly level is yet to emerge.

[60] Values shown are nameplate capacities and are sourced from each project's respective website.

Figure 1-15 below presents a summary of wholesale load distributions by quarter over the past five years. The box plots show several statistical measures of load levels and variability, including minimum, maximum, median, mean, as well the interquartile range (IQR).[61]

Figure 1-15: Quarterly Wholesale Load Distributions



Quarterly load distributions show greater variation in Q3, when summer demand is more sensitive to fluctuations in temperature and humidity. For example, the average interquartile range (IQR) in Q3 was approximately 4,500 MW, compared to about 2,800 MW in Q2 over the same five-year period. Average and peak demand during the colder Q1 months continues to be significantly lower than Q3 levels, a statistic that is expected to reverse in a decade.

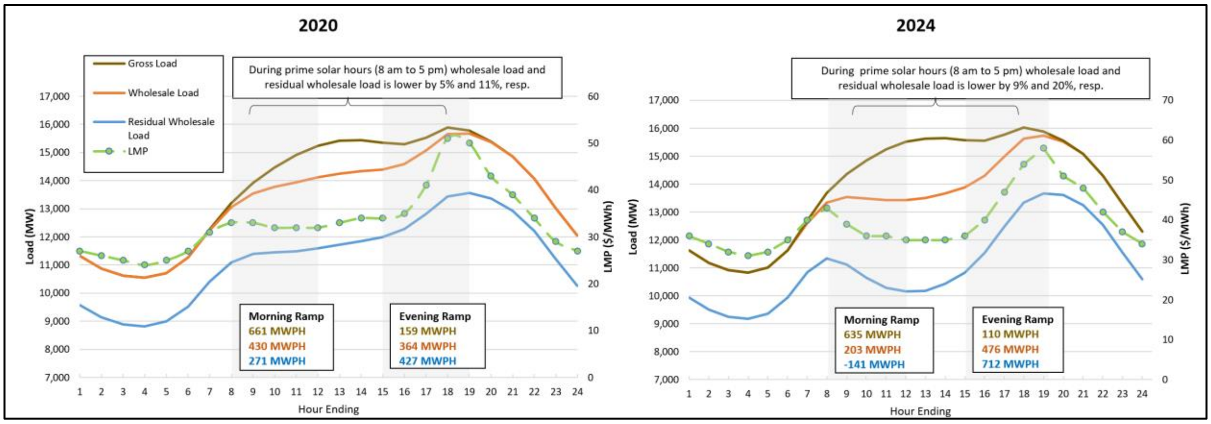
1.5.2 Market Interactions

While the overall impact of additional intermittent resources (such as wind and solar) has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. Figure 1-16 below compares the hourly load profiles for 2020 and 2024, with emphasis on the morning (7am to 11am) and evening ramp (4pm to 7pm) periods and the correlation with LMPs.[62]

[61] The IQR represents the middle 50% of the data, with 25th percentile and 75th percentile marking the boundaries. The higher the IQR, the larger is the variability of data. Upper whiskers extend from the 75*th* quantile to the highest data point that falls within 1.5 times the IQR. Lower whiskers extend from the 25*th* quantile to the lowest data point that falls within 1.5 times the IQR. The whiskers determine the upper limit of what is considered a "typical" value. This is intended to separate unusually high values from the rest of the data. Data points above that limit are plotted individually (as dots).

[62] We do not attempt to quantify the impacts on pricing levels here but rather focus on the time-of-day pricing impacts. However, to allow for a more direct comparison between the two bookend years in this report section, we adjusted 2020 prices to account for differences in natural gas prices (with the important caveat that other supply and demand factors also impact energy prices). The hourly average 2020 LMP is adjusted by the ratio of 2024 average natural gas price to the 2020 average gas price.

Figure 1-16: Hourly Real-Time LMP and Demand Profiles, 2020 vs. 2024

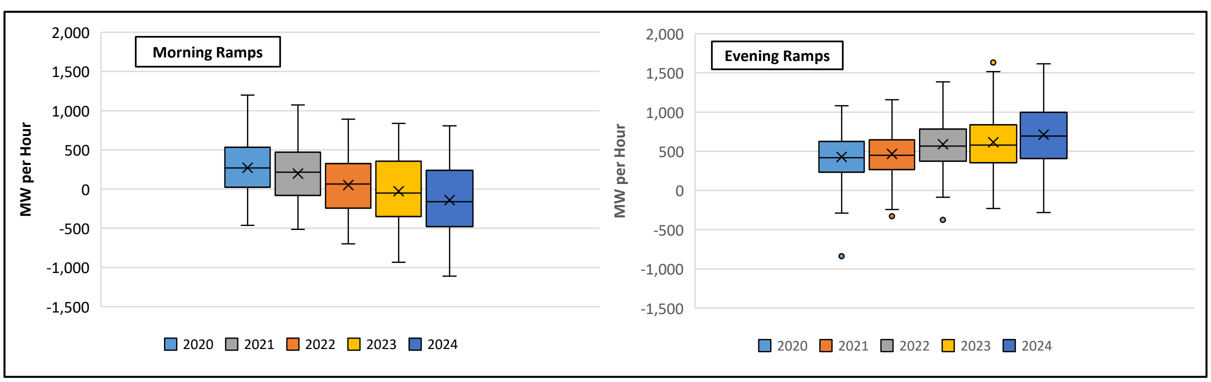


There is a substantial change in the hourly load profiles, with BTM solar moderating wholesale load ramps in the morning and increasing evening load ramps. In particular, the impact on morning and evening ramps has grown; for example, the ramp in "residual wholesale load" during the evening hours has increased from 427 MW per hours to 712 MW per hour between 2020 and 2024.

Real-time prices increase early in the morning then dip mid-morning as solar production increases and consequently load decreases. Energy prices have become higher during the morning ramp, and to a greater extent during the steeper evening ramp, when more expensive supply is dispatched to meet load.

Higher penetration of intermittent resources not only has changed the average hourly ramps but also their variability and therefore uncertainty about the amount of dispatchable generation needed to meet the residual wholesale load[63] during the morning and evening peaks. Figure 1-17 below contains graphs showing the daily morning and evening ramps distribution for residual wholesale load.

Figure 1-17: Morning (7am to 11am) and Evening Ramps (4pm to 7pm) Distribution



The interquartile range (IQR) has increased over the period during the evening *upward* ramps, from 375 MW per hour in 2020 to 590 MW per hour in 2024 (or 57% increase) indicating a larger spread in ramp rates in the middle 50% of the distribution. The first and third quartiles

[63] The portion of load that cannot be met by intermittent generation.

(Q1 and Q3) also increased by 75% and 60%, respectively. For example, in 2024, ramps were at least 1,000 MW per hour in 25% of the days; in 2020, that statistic was 620 MW.

The impact of intermittent generation in the morning ramps is increasing *downward* ramping. For example, during half of all days ramps were below *negative* 160 MW per hour (positive 268 MW per hour in 2020) and in 25% of the days, ramps were below *negative* 477 MW per hour in 2024 (but positive 24 MW per hour in 2020). The IQR has increased by 40% from 500 MW per hour (2020) to 700 MW per hour (2024). As the grid transitions to include more intermittent generation, large changes in residual wholesale demand will place a premium on flexible, dispatchable generation.

The wholesale demand "duck curve" has become a common occurrence over the last five years, and with solar capacity projected to double over the next 10 years, it will increasingly present challenges for both markets and system operations. Lower demand in the middle of the day will put downward pressure on real-time prices that could have negative impacts on profitability of dispatchable generation. Historically, the lowest demand has occurred during the nighttime, but there has been a notable increase in the frequency of minimum residual wholesale load occurring later - between 8am and 3pm. The frequency has increased from 5% in 2020 to 38% in 2024.

To date, we have not observed over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower mid-day load, we have observed changes in flexible demand[64] shifting consumption from overnight to mid-day hours, albeit with a quite moderate load impact on an aggregate load. Low energy prices in the early afternoon hours will create opportunities for the growing amount of energy storage resources to charge in anticipation of higher prices during the evening load ramp, thereby smoothing out wholesale load and price changes.

While impacting the load ramp, solar generation has not increased the frequency with which the system is ramp-constrained and the number of ramp-constrained intervals has remained very low in the past five years.

1.5.3 Downward Flexibility of Supply

Minimum generation events, or over supply conditions, occur when fixed (i.e., non-dispatchable) supply is at risk of exceeding load. By 2032, high BTM solar penetration may, under certain scenarios, result in baseload generation levels exceeding wholesale demand, according to ISO-NE's 2024 EPCET study.[65] In such cases, baseload generation—particularly inflexible nuclear units—may exceed wholesale demand, resulting in the curtailment of renewable resources. While some conventional generators may be able to decommit, their long start-up times can limit flexibility and hinder their ability to respond to later increases in load.

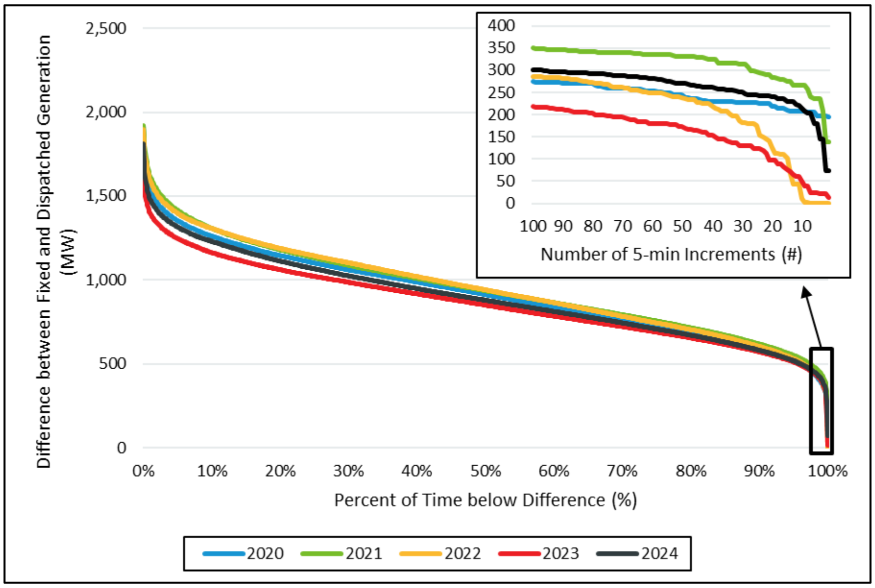
Examining the difference between dispatched and fixed generation on the system in an interval provides an assessment of the risk of over-supply conditions. Figure 1-18 below, shows a duration curve of downward flexibility on the system. Fixed generation is defined as generation

[64] Pumped and battery storage resources

[65] See the ISO's *Economic Planning for the Clean Energy Transition* report (October 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf

up to economic minimum output, plus any generation each generator must produce due to ramp constraints.

Figure 1-18: Downward Flexibility of Supply

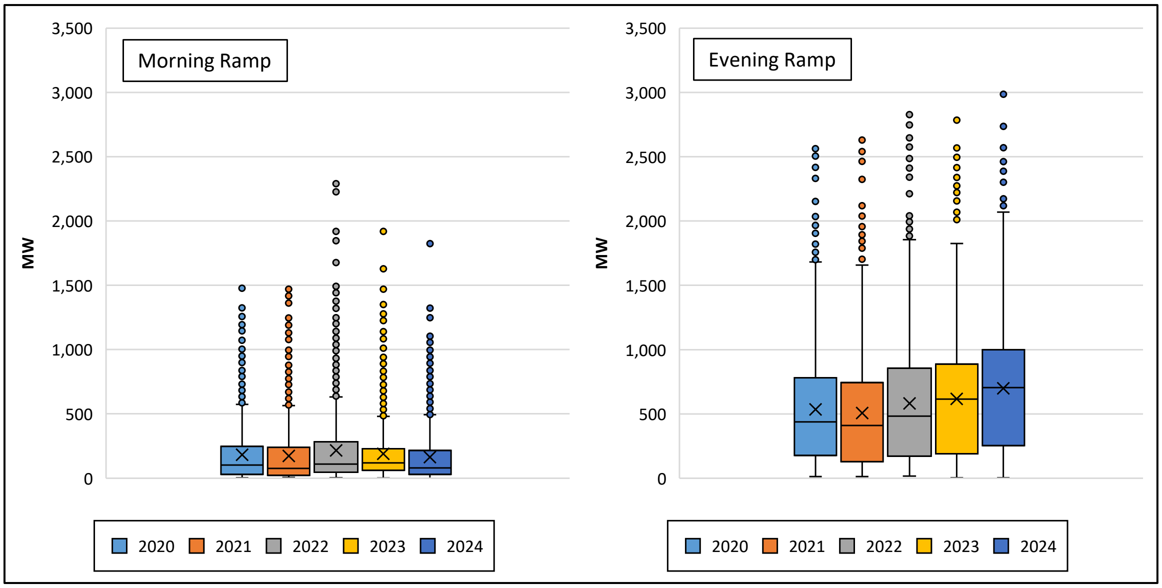


Between 2020 and 2024, there has not been a significant downward shift in the duration curves, as we would expect if the risk of minimum generation conditions was increasing. The average downward flexibility of supply in the tightest 1% of intervals in 2024 was 370 MW, similar to the average between 2020 and 2023 of 362 MW. Looking at the tightest 100 intervals (inset chart), 2024 was typical of the past five years. On May 21, 2022, there were 35 minutes in which there was no downward flexibility of supply in the generation fleet and the ISO declared a minimum generation emergency. There have not been any minimum generation emergencies since.

1.5.4 The Reliance on Existing Fast-Start Generation is Increasing during Evening Ramps

Fast-start units provide operational flexibility, which may be relied upon during ramping periods. Figure 1-19 shows the distribution of hourly fast-start generation during morning and evening ramp periods.

Figure 1-19: Fast-Start Generation during Morning and Evening Ramp Periods



Fast-start generation plays a more significant role in the relatively steep evening ramp period than the morning ramp period. Fast-start generation during the morning ramp period (7am to 11am) declined over the past three years, while fast-start generation has increased during evening ramp periods (4pm to 7pm). Peak evening ramp fast-start generation reached up to 3,000 MW per hour in 2024. While fast-start generation has been dispatched at an increasing rate in evening ramp periods, surplus fast-start capacity exists to meet growing ramps.[66] Fast-start generation averaged less than 20% of offered fast-start capacity during evening ramps in 2024, and did not exceed 60% of offered fast-start capacity during ramping periods in any hour.[67]

1.5.5 Load Forecasting and Operational Uncertainties

As the system evolves to comprise more weather dependent supply (including BTM solar and storage), operational uncertainties and challenges due to unanticipated changes in demand are expected to increase. The ISO's multi-year roadmap and annual workplan has a number of important initiatives geared towards aligning market design and systems/tools with operational and reliability challenges, including:[68]

- short-term probabilistic load forecasting methodologies to account for load uncertainty,
- forward-looking intra-day (real-time) market clearing and multi-interval pricing to position and optimize supply to meet changes in net load and load uncertainty,
- evaluating the system's needs for flexible response capabilities and market products to address greater operational uncertainties.

[66] Uncommitted fast-start capacity represents only one available method to meet evening ramps alongside dispatch of already-online units.

[67] Fast-start offered capacity is calculated as the sum of hourly offered economic maximum limits from units that are both fast-start capable and fast-start qualified.

[68] See ISO New England's *Multi-Year Roadmap*, presented by Vamsi Chadalavada, (November 6, 2024), available at https://www.iso-ne.com/static-assets/documents/100017/nov-6-2024-iso-bod-open-meeting-master-slides-final.pdf

The IMM strongly supports these initiatives, as they reflect a proactive approach to aligning emerging and future reliability needs with wholesale market tools and products. These efforts are critical for price formation and market efficiency, helping to avoid reliance on manual reliability actions that are neither priced nor visible to the market.

While load uncertainty and forecasting challenges are expected to grow in the future, it is worth examining trends in load forecast error in recent years.[69] To assess this, we reviewed the accuracy of the day-ahead load forecast compared to real-time load and found that there is no discernable deterioration in the accuracy of the load forecast.

The ISO publishes a day-ahead load forecast around 9:30am as the last load projection prior to the close of the day-ahead market for the next operating day.[70] While the ISO forecast was not a direct input into the day-ahead market (prior to the implementation of Day-Ahead Ancillary Service in March 2025[71]), its publication provides transparency into operational planning and is often referenced by participants submitting day-ahead demand bids.[72, 73] Load forecast error historically has a statistically significant impact on day-ahead and real-time price differences. Figure 1-20 below illustrates annual hourly load forecast error with boxplots.[74]

[69] In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see ESIG's article *Building data intelligence for short-term load forecasting with behind-the-meter PV,* by Jon Black, (March 27, 2019), available at https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/

[70] Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. See ISO's *Three-Day System Demand Forecast* page, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast

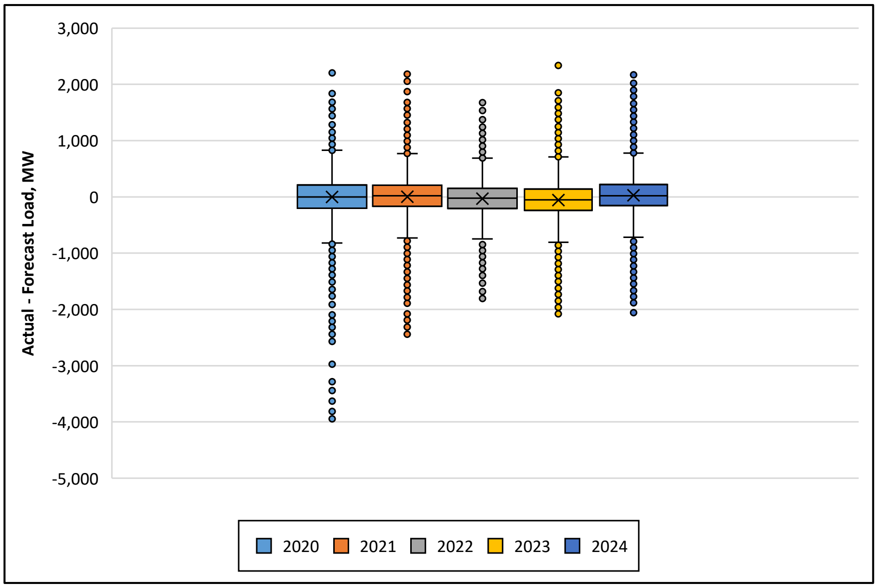
[71] With Day-Ahead Ancillary Services the load forecast is a direct input and constraint that prices and procures sufficient energy for physical supply in the day-ahead market.

[72] Load Serving Entities (LSEs) may also rely on their own in-house or third party forecasting tools to inform their day-ahead bidding strategy.

[73] Additionally, as mentioned in Section 3.4, the load forecast is used in the RAA process to finalize the ISO's next day operating plan.

[74] For this visualization, forecast error is defined as actual load minus forecasted load. Outliers are suppressed in this graph.

Figure 1-20: Hourly Load Forecast Error

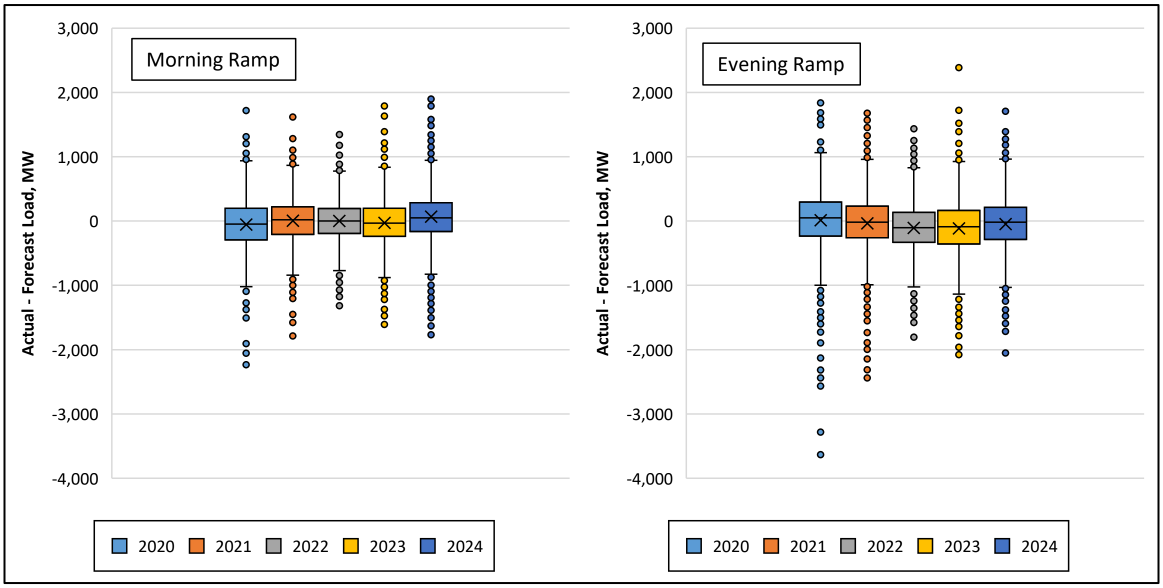


Load forecast error followed a similar distribution in 2024 relative to prior years. Forecast errors are centered around 0 MW, indicating that forecasts are unbiased on average. The 25th and 75th percentile range of forecast error typically falls between -200 and 200 MW. While forecast errors typically fall in this range, some hours exhibit extreme forecast errors. There were 325 hours where absolute forecast error exceeded 1,000 MW in 2024. As discussed in Section 3.4.3, significant forecast errors can have implications for price convergence between the day-ahead and real-time energy markets.

Load forecast error may vary by time of day. In particular, load forecasts during morning and evening ramp periods may be challenged by relatively unpredictable BTM solar generation. Figure 1-21 shows the distribution of load forecast errors during morning and evening ramp periods.[75]

[75] The morning ramp period is defined as 7-11am, and the evening ramp period is defined as 4-7pm.

Figure 1-21: Hourly Load Forecast Error during Morning and Evening Ramp Periods

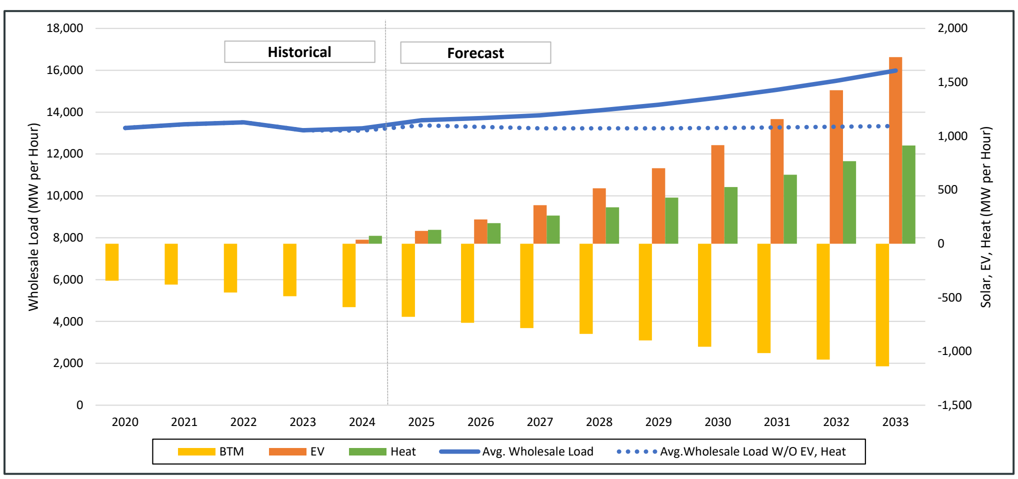


Load forecast error followed a similar distribution in morning and evening ramp periods in 2024 relative to 2023. Actual loads were slightly more likely to be above forecast during morning ramps in 2024 relative to prior years.

1.5.6 Level and Drivers of Expected Load Growth

The ISO develops peak load and the energy forecast for the ISO-NE Control area every year. Figure 1-22 below shows the historical and 10-year forecast of average annual load, along with the major drivers. [76]

Figure 1-22: Historical and Forecast Average Hourly Load and Major Drivers (BTM solar, EV, and Heat)

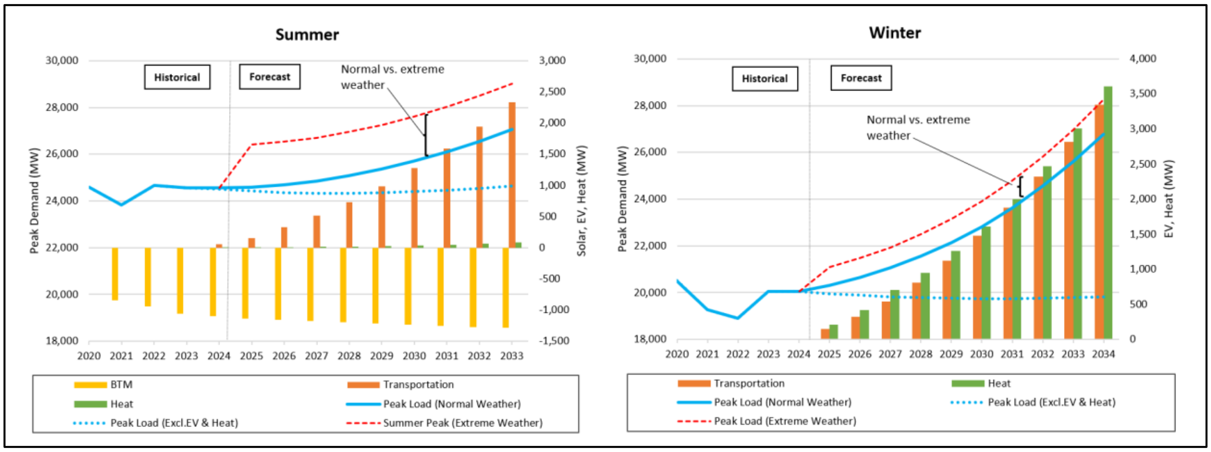


[76] Since this was report was written, the ISO has updated its long-run energy and peaks forecast. The 2025 draft forecast has revised down the forecast of energy and summer & winter peaks. For example, in 2033, the average hourly load is 8% lower than the most recent published forecast. Summer and winter peak projections for 2033 are down by 1.2% and 8% in the summer and winter respectively

ISO-NE projects an increase in average hourly load of 17% between 2023 and 2033, driven by the adoption of electric vehicles as well as extensive electrification of space heating and water heating in the residential and commercial sectors. Transportation and heat electrification are expected to play a pivotal role in the achievement of New England state greenhouse gas (GHG) reduction mandates and goals.

A similar trend is expected for the summer and winter peak loads as shown in Figure 1-23 below.

Figure 1-23 : Forecast of Summer and Winter Peaks Under Expected and Extreme Weather Conditions



Summer and winter peak loads are expected to grow between 2025 and 2033 by 10% and about 26%, respectively. Without transportation and heating electrification, the average hourly load, summer, and winter peaks would remain flat or even negative in the case of the winter peak (dotted lines, left axis).

The contribution of BTM solar is expected to slow down as the marginal impact of reducing the peak will decline as installed capacity grows. By 2033, the impacts of EV adoption add about 2,300 MW and 2,800 MW to the summer and winter peak loads, respectively. By 2033, the difference between summer and winter peak loads is expected to shrink from 4,000 MW in 2020 to 1,440 MW. This is because heat electrification will contribute to increase the winter peak every year, adding up to 3,000 MW of heating load by 2033.

The uncertainty around the expected summer and winter peak load due to extreme hot or cold weather conditions is also captured in the above figure. Summer peak loads under extreme weather conditions are about 1,900 MW higher than the expected peaks. In the summer, the year- after-year difference between expected and extreme forecast remains close to the average impact during the entire forecast period. However, the impact of extreme weather on winter peaks grows much faster due to the increasing penetration of heat pumps replacing alternative fuels.

1.6 Generator Profitability

Wholesale electricity markets coordinate the efficient entry and exit of supply resources through price signals that reflect system reliability needs and compensate resources for the costs of providing system services. The profitability metrics presented here evaluate the financial incentives conveyed by New England markets to two types of decision-makers: prospective investors considering new entry, and current owners assessing whether to remain in the market.

> ***Key Takeaways***
>
> **New Entry:** Market-based revenues are insufficient to cover the going-forward costs of new entrant gas-fired generators. The profitability of wind and solar units in the region remains intricately linked with state policies, with both technologies generally relying on additional revenue streams to those in the wholesale markets to be economically viable. Net revenues for the typical battery resource in the region have steadily decreased since 2021, driven largely by a decline in regulation service revenues.
>
> **Existing Resources:** Combined-cycle (CC) plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have relied on the capacity market to a greater extent. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market over the same period. These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

1.6.1 New Resource Profitability Metrics

In this subsection, we examine whether the revenue available from the ISO-NE wholesale markets and other relevant markets and programs (e.g., Renewable Energy Certificates (REC) markets and the Solar Massachusetts Renewable Target (SMART) program) is sufficient to support the entry of certain types of new generation (gas-fired, solar, wind, and battery resources).

Gas-fired Generators

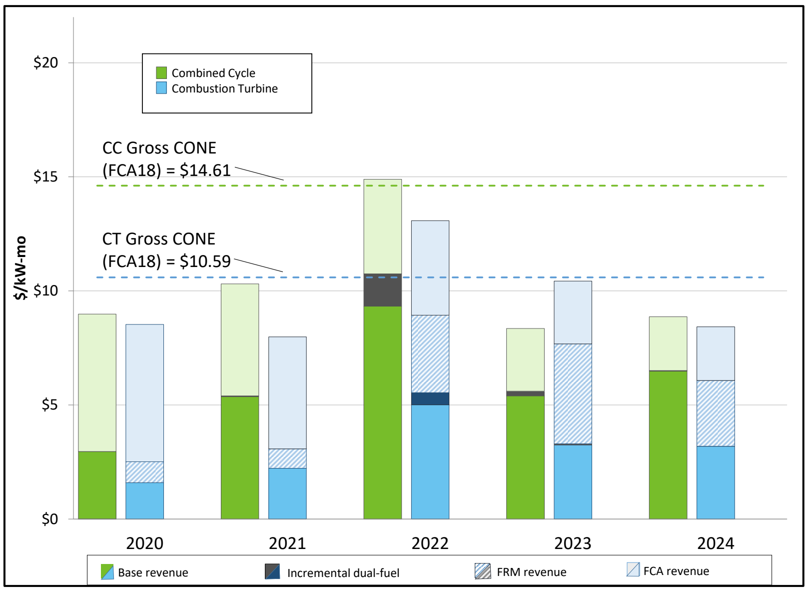
We present estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the revenue required from the capacity market to build a new generator, the section also highlights the incremental revenue that could be earned from dual-fuel capability and evaluates participation in the Forward Reserve Market (FRM) for a combustion turbine generator.[77]

[77] A forward reserve resource receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is very high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. Note that FRM-based revenues are no longer available as of the implementation of the Day-Ahead Ancillary Services Initiative on March 1, 2025.

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down times, and economic limits.[78] The simulation model also includes a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO_2 emitted.[79]

Figure 1-24 shows the result of the simulations. Each stacked bar represents revenue components for a generator type and year. The simulation produces baseline revenue (energy and ancillary services (AS)) and incremental dual-fuel revenue numbers for 2020-2024.[80] The FCA revenue numbers shown are calculated using the actual payment rates applied to calendar years. For reference, the most recent Gross Cost of New Entry (Gross CONE) values for CC and CT generators in the Forward Capacity Auction for the 2027-2028 Capacity Commitment Period (FCA 18) are also shown in Figure 1-24.[81] The remainder of this section discusses estimated base revenues, incremental dual-fuel revenues, and FRM revenues, before comparing the total estimated revenues to Gross CONE benchmarks.

Figure 1-24: Estimated Net Revenue for New Gas-fired Generators



In 2024, estimated base net energy and ancillary services revenues diverged between the CC and CT units compared to the prior year. Specifically, the simulation results show base revenues increased by approximately 20% for the combined cycle generator and declined by approximately 2% for the combustion turbine. One explanation—consistent with the

[78] The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new generator).
[79] In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year. For RGGI auction data, see RGGI's *Allowance Prices and Volumes* data, available at https://www.rggi.org/auctions/auction-results/prices-volumes.
[80] Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.
[81] The Gross CONE values for the CC and CT gas-fired generators reflect Net CONE values of $10.50/kW-month and $6.33/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales. See ISO's *2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price* update, available at https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

differences in operational flexibility and efficiency—is that our model schedules CCs primarily in the day-ahead market due to their higher efficiency and predictable baseload role, whereas CTs rely on real-time dispatch, reflecting their fast-start peaking function. Qualitative analysis of price shifts shows that day-ahead prices exhibited more frequent and sustained year-over-year increases compared to the more volatile real-time market. As a result, CCs captured a larger share of the upward price movements, while CTs, dependent on episodic real-time price spikes, experienced a slight revenue decline.

Second, like the prior year, dual-fuel capability did not add significant revenue to either technology type, with the hypothetical generators earning negligible incremental revenues to net revenue this year. These muted incremental dual-fuel capability benefits are due to continued inexpensive gas reducing opportunities for oil generation for most of the year.[82]

Third, participation in the FRM yielded an additional $2.88/kW-month to the CT generator's net revenues, a 34% decrease over the previous year's contribution. The decline is consistent with the decline in FRM auction-clearing prices and payments discussed in Section 7.2.[83]

For reference, the most recent CONE revisions approved by FERC for FCA 18 establish net revenue components of $4.12/kW-month and $4.27/kW-month for combined cycle and combustion turbine generators respectively.[84] The estimated revenues from the IMM's simulations for both the CC generator and the CT generator that participates in the FRM exceed these net revenue benchmark estimates. However, these estimated revenues are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator.[85] In recent years, capacity prices have remained low reflecting a system that is long on capacity. Consequently, total revenues from the energy and capacity markets appear insufficient to incent either type of gas-fired generator to enter the region's energy market.

Wind and Solar Units

In this section we estimate the profitability of wind and solar power investments within the ISO-New England power market to provide insight into the economic viability of wind and solar projects in the region. Renewable energy projects in the region receive significant portions of their overall revenue from state-level programs that exist outside the standard wholesale electricity markets. These "out-of-market" streams, such as Renewable Energy Certificates (RECs) or the Solar Massachusetts Target (SMART) program, offer price supports or production-based incentives that can be critical for a project's financial viability. Out-of-market revenues may also impact an eligible facility's bidding behavior, potentially distorting the

[82] See Section 1.2 of this report for more detail.

[83] As mentioned in Section 7.2, the lower auction-clearing prices followed FERC's approval of a market rule change that revised the FRM offer cap downwards. The IMM had previously recommended reviews and updates to the forward reserve offer cap.

[84] These revenue components include "Pay-for-Performance" (PFP) revenue which this study does not. See ISO's *2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price* update, available at https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

[85] Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

energy market price signal. This analysis examines how the interaction between state policies and market conditions affect the profitability of these renewable resources.

In the analysis, we consider two representative units: (1) an onshore wind unit whose generation profile reflects typical wind generators in New England, and (2) a solar unit whose profile matches that of solar installations across the region. Both resource types are assumed to offer 53% of their generation into the day-ahead energy market at their short-run marginal costs.[86]

Although solar and wind resources have approximately zero marginal costs, which would imply economic offers at $0/MWh, such resources typically have out-of-market arrangements that provide revenues when they generate energy, and thus have an incentive to offer their energy into wholesale markets at negative prices. In our analysis, the wind unit offers into the day-ahead and real-time energy markets at a price equal to the negative of the annual average MA Class I REC price, while the solar unit offers at the negative of the SMART program compensation rate. In both cases, the units clear the energy market whenever the LMP at the Hub exceeds their offers.[87] In our analysis, the units do not provide ancillary services. However, the units earn FCA revenues in proportion to the qualified capacities assumed in recent offer review trigger price (ORTP) analyses.[88] Figure 1-25 summarizes the findings.

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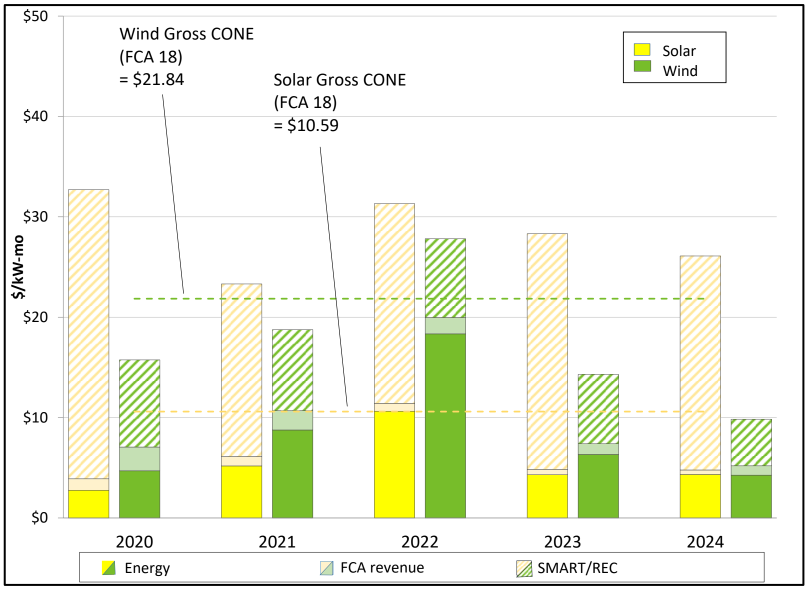
[86] See ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward (December 2020), p. 88, available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

[87] This analysis does not account for revenue streams from Power Purchase Agreements (PPAs), focusing instead on Renewable Energy Certificates (RECs) and the SMART program. The SMART program is a Massachusetts tariff-based incentive structure that provides eligible facilities a fixed base compensation rate per MWh of electricity generated. The base compensation rates decline over time through a capacity block structure – as each capacity block (representing a set amount of capacity added to the system) is filled, the base rate for the next block decreases. Under the SMART program, a standalone facility receives a total compensation rate comprised of the base rate plus any applicable adders. When the wholesale price is below this all-in rate, the program makes up the difference so that the facility's effective revenue per MWh is topper up to the all-in rate. If the LMP rises above the all-in rate, the solar facility does not receive a top-up payment and instead earns its revenue entirely from the wholesale market.

To determine the SMART compensation rate for the hypothetical solar unit, we set its characteristics to match the most popular combination of electric distribution company (and corresponding capacity block), unit capacity, and land type among standalone, commercial units that went commercial during the analysis year. For example, in 2024, this corresponds to the 55 building-mounted facilities with a 250 kW AC in capacity block 7 of Eversource's MA East service territory. Based on these assumptions, the solar unit is eligible for a base compensation rate of $0.19960/kWh, consistent with the seventh capacity block established for Eversource MA East, and a $0.01920/kWh location adder, resulting in a total SMART compensation rate of $0.19962/kWh. Specifically, this total compensation rate is used to "top up" the unit's hourly real-time energy revenues to $199.62/MWh whenever the hourly real-time LMP is less than $199.62/MWh. For each unit of energy generated in real-time in a given year, the wind unit earns the average Massachusetts Class I REC Index price in that year.

[88] Solar and wind units earn 18.9% and 39.3% respectively of the $/kW-month FCA revenue for each kW capacity. See the 'Assumption' sheet of the ISO's *2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price* update, available at https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

Figure 1-25: Estimated Net Revenue for Solar- and Wind-Powered Units



The profitability of wind and solar units in the region remains intricately linked with state policies, with both resource types generally relying on additional revenue streams to those in the wholesale markets to be economically viable. With the exception of 2022, the solar unit would have earned 75% to 90% of its revenues from the SMART program; similarly, about half of the wind unit's revenue outside of 2022 would have been attributable to RECs. While these policies help to meet the region's clean energy targets, their economic impact on wholesale market prices due to their operational and bidding strategies require careful consideration to maintain market efficiency and reliability.[89]

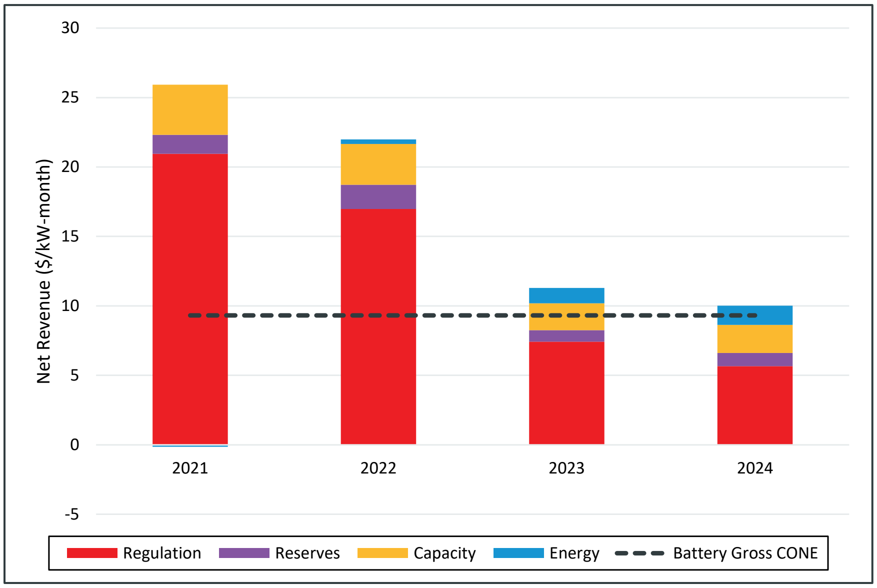
Battery Storage

To assess the profitability of a proxy battery unit, we rely on data from ISO settlement records, including day-ahead and real-time energy sales and purchases, ancillary services, NCPC credits and charges, and Pay-for-Performance. Capacity prices are calculated using the FCA clearing price multiplied by the percentage of accredited capacity associated with a CSO. Figure 1-26 shows the different revenue sources available to batteries in the region.[90]

[89] For example, energy market prices may be distorted, with negative clearing prices prevailing whenever solar or wind units benefiting from these policies are marginal.

[90] To preserve confidentiality of participant information, only 2021 through 2024 are shown due to low sample size in 2020.

Figure 1-26: Net Revenues for Battery Resources



Total net revenues across battery resources peaked in 2021 at nearly $26/kW-month and gradually declined to just over $10/kW-month in 2024. This high-water mark in 2021 was largely driven by substantial revenue from regulation service, which diminished over subsequent years. Although capacity payments declined steadily—from $3.62/kW-month to $2.02/kW-month by 2024, the decline in regulation credits was the primary driver of the falling total revenues. Energy margins, meanwhile, were initially small or negative in 2021 and 2022, reflecting the cost of charging the battery from the grid; by 2023 and 2024, these margins became modestly positive.

Looking more closely at the breakdown of net revenues reveals that regulation credits have been the standout contributor, despite their decline after 2022. Capacity revenues, which include both base FCM payments and pay-for-performance incentives, became a more significant part of the revenue stack over time. Reserve revenues also added modest but consistent value.

However, when compared with a gross CONE estimate of $9.31/kW-month, the total net revenues for these batteries (varying from about $10 to $26/kW-month) indicate that market participation, particularly in regulation and capacity, remains critical for them to meet or exceed the benchmark. Overall, these findings underscore how essential it is for battery resources to capture multiple revenue streams—especially regulation credits and capacity payments—in order to secure a viable return in New England's markets.

1.6.2 Existing Resource Profitability Metrics

Over the past five years, combined-cycle (CC) plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have been much more reliant on the capacity market. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market over the same period.[91] These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

Using ISO settlement data and submitted offer data, we estimated revenues and costs for each resource in the ISO-NE footprint. Specifically, we used day-ahead and real-time energy, reserves, regulation, NCPC credits and charges, forward reserves, capacity base payment, pay-for-performance (PfP), and inventoried energy program (IEP) revenue data. We estimated generator costs using participant-submitted offers.[92]

Figure 1-27 below shows the net revenues of CTs and ICs per kW-month (of seasonal claimed capability) between 2020 and 2024. Note, to allow for easier visual comparison, the scale for each technology type is fixed from -$2 to +$16/kW-month. Revenues are broken into five categories:

- The first four include energy and ancillary services, forward reserves, PFP credits/charges, and IEP estimates between 2020 and 2024 and are based on actual revenues.
- The fifth category of capacity market base payments is calculated using the capacity auction clearing price, adjusted for the percentage of seasonal claimed capability that has a capacity supply obligation.[93]

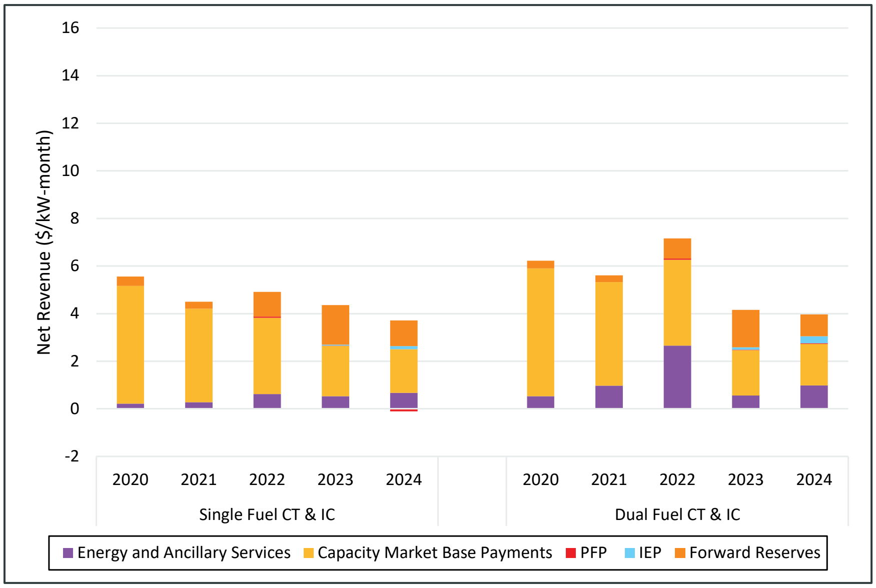
Note that the IMM does not have going forward cost (GFC) data that is reliable or that can be published with this analysis. Comparing the net revenues shown below to GFC data would provide an indication of whether the technology type receives sufficient revenues from the wholesale markets to cover its fixed operating and amortized capital costs.

[91] Combined cycle units are typically newer, more efficient, and slower-starting units (the average commercial year of combined cycle units is 1998). Gas turbines and internal combustion generators are combined in the charts below. Gas turbines tend to be newer (average commercial date in 1989), faster (nearly all fast-start capable), and are mostly oil-fired or dual-fuel units. Internal combustion engines are typically oil-fired, older (average commercial date in 1975), and are a mix of fast-start-capable and slower-starting units. Steam turbines are the oldest units, on average (average commercial date in 1967), non-fast-start units that are oil-fired.

[92] About 2% of total asset-year observations were omitted from the analysis due to unique circumstances in which generators' known incentives do not align with a typical generator in each category.

[93] This provides a realistic picture of the capacity revenues a generator in these categories can expect to receive. For example, in 2024 78% of the CT and IC single fuel asset seasonal claimed capability (SCC) was linked to a capacity supply obligation. The average 2024 FCA clearing price was $2.36/kW-month of CSO, giving a per-kW-month of SCC capacity base payment of $1.84 ($2.36 times 78%).

Figure 1-27 : Combustion Turbine and Internal Combustion Generator Net Revenues



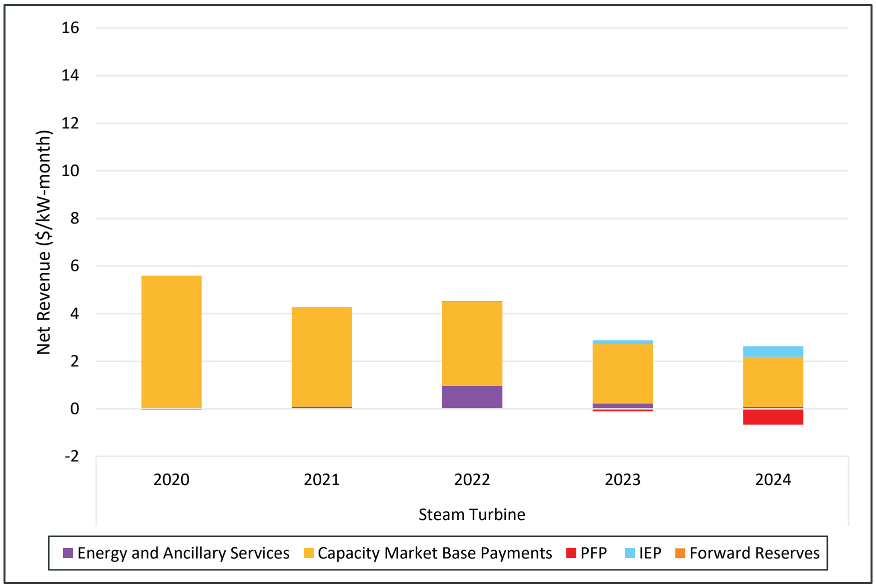
CTs and ICs are fast-start generators with relatively high operating costs and low utilization rates that are typically deployed during peak demand periods. Net revenue (gross margin) from the energy and ancillary services markets represents a small proportion of overall net revenues (16%) between 2020 and 2024. A similar share (17%) of revenues comes from the Forward Reserve Market (FRM). The capacity market provides the majority of revenues (two-thirds) through base payments. The now-expired IEP provided a relatively small incremental (3%) source of revenue, indicating that IEP is unlikely to have a significant impact on retirement risk for these assets.

The FRM was sunset in February 2025 and replaced by the Day-Ahead Ancillary Services market, which will provide compensation to participating resources through payments for Flexible Response Services and day-ahead energy.[94]

Figure 1-28 shows the net revenues of steam turbines (STs) and internal combustion engines (ICs) per kW-month of seasonal claimed capability between 2020 and 2024, broken into the same categories as the above graph.

[94] An impact assessment of the new DAAS design was shared by the ISO during the April 11-13, 2023 NEPOOL Market's Committee. See the ISO's *Day-Ahead Ancillary Services Initiative (DASI)* presentation, available at iso-ne.com/static-assets/documents/2023/04/a07a_mc_2023_04_11-13_dasi_design_r1.pdf

Figure 1-28 : Steam Turbine Generator Net Revenues

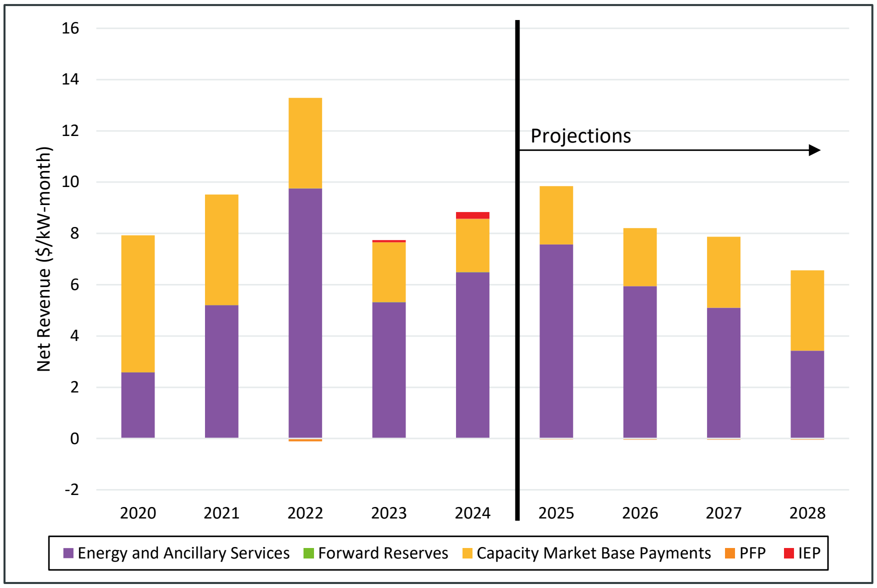


Steam turbines are even more reliant on capacity market base payments (95% between 2020 and 2024) than the CT and IC generators discussed above. Pay-for-performance represented a net cost to these resources, reducing capacity payments by almost a third in 2024, due to resource economics and long-lead times that prevented them from reacting to unanticipated and transient capacity scarcity conditions. The energy and ancillary services markets provide less than 10% of the net revenue, while IEP provided 22% of incremental revenues in 2024.

Figure 1-29 below shows the net revenues of combined cycle units (CCs) per kW-month of seasonal claimed capability between 2020 and 2024. In addition, projected revenues for 2025-2028 are shown based on forward commodity pricing data.[95] Gas and dual-fuel units are not separated in this chart, because dual-fuel capability did not produce incremental revenues in the observed outcomes.

[95] Energy and ancillary revenues are projected by scaling the average historical net revenue by the forward clean spark spread. The clean spark spread is estimated using historic and future on-peak energy prices, AGT gas prices, and RGGI prices sourced from S&P, Bloomberg, and ICE. Forward RGGI prices were only available until 2027, therefore 2027 prices are applied to 2028. The forward projections are not adjusted for the impact of DA A/S on energy and ancillary service numbers given the infancy of that market. FCM base revenues are projected forward using actual FCA cleared prices. PFP revenues are projected by taking the average PFP settlements between 2020 and 2024. The PFP revenues are projected forward using the average PFP revenues from those years, scaled by the increases in the PFP rate ($2,000 from June 2018 until May 2021, $3,500/MWh from June 2021 until May 2024, $5,455/MWh in June 2024 and $9,337/MWh in June 2025).

Figure 1-29: Combined Cycle Generator Net Revenues



Combined cycles generators are relatively efficient with significantly higher utilization rates than the other technologies covered up to this point. About 62% of combined cycle net revenues are from the energy and ancillary services market, with almost all of the remaining revenue (37% on average) earned through capacity market base payments.

Forward prices indicate that clean spark spreads will increase in 2025 and decrease in following years. Specifically, after an initial increase in spark spreads due to higher gas and energy prices, both gas and energy price futures decrease from 2025 until 2028. LMP future prices in 2025 through 2028 are higher than in 2024 (20% increase in day-ahead on-peak hub LMPs between 2024 and 2028) but are more than offset by an increase in gas prices (83% increase in gas prices between 2024 and 2028). RGGI futures indicate similar prices between 2024 and 2028.

Section 2
Market Structure and Competitiveness Assessment

In this section, we assess the level of competition in the wholesale electricity markets. Competition ensures that the prices consumers pay and that producers receive are the result of competitive forces, and are not unduly influenced by market power. If electricity markets are unable to achieve competitive outcomes due to the potential exercise of market power, mitigation controls are necessary. The IMM performs reviews across various ISO electricity markets to identify these situations and limits their impact through the market power mitigation process and through its monitoring and investigation functions.[96]

The section is structured as follows:

- Energy Market (2.1) followed by energy market mitigation (2.2),
- Financial Transmission Rights market (2.3), and
- Ancillary Services Markets, encompassing the Forward Reserve Market and the Regulation Market (2.4).

2.1 Energy Market Competitiveness

A number of metrics are utilized to assess the structure and competitiveness of the energy markets; specifically:

- the high-level market concentration measures for the supply side (2.1.1) and demand side (2.1.2) of the real-time market,
- supply-side structural market power tests in the day-ahead and real-time markets (2.1.3): pivotal supplier test (PST) and the residual supply index (RSI),
- supply offer cost mark-up metrics in the day-ahead (2.1.4) and real-time markets, and
- the level of capacity economically withheld in the real-time market (2.1.5).

Key Takeaways

Market outcomes were competitive overall, and the exercise of market power was generally not a concern. Although price-cost markup metrics in both the day-ahead and real-time markets were higher than in previous years, they remained well below the tightest mitigation threshold of 10%. These results indicate that competition among suppliers effectively limited the ability to inflate LMPs by submitting offers above marginal cost.

Market Concentration: The share controlled by the largest four firms (the "C4" metric) remained consistent with the past five years: approximately 40% on the supply side and 55% on the demand side in the real-time market, with no single firm highly dominant.

Pivotal Suppliers: Pivotal suppliers were relatively low in the day-ahead market, occurring in only about 2% to 4% of hours. In the real-time market, pivotal suppliers were present in 33% of hours, a slight decrease compared to 2023. When a pivotal supplier was present, approximately

[96] Importantly, the IMM does not have defined mitigation authority for certain markets, including the Regulation and Forward Reserve Markets.

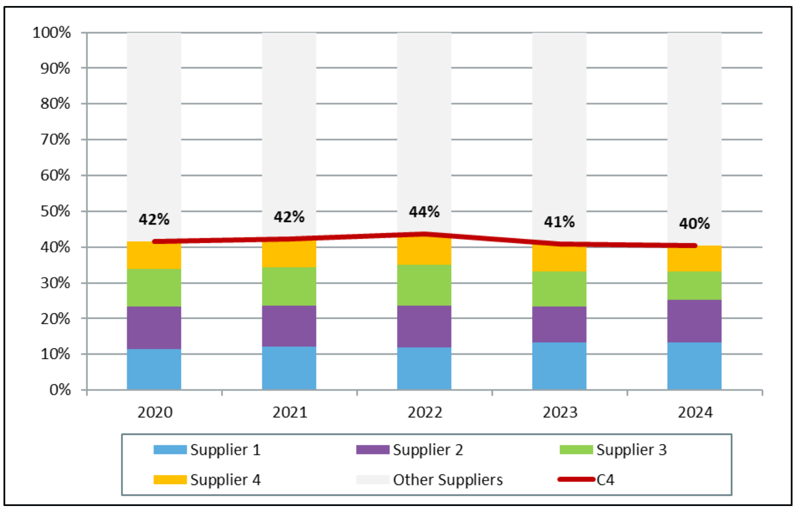
96% of load and operating reserve requirements could still be met without relying on the largest supplier.

Economic Withholding: In the day-ahead and real-time markets, annual load-weighted markups were close to zero or negative from 2020 to 2023 but in 2024 increased to 2.4% and 6.8%, respectively. The increase was primarily driven by gas-fired generators offering above marginal cost, whereas historically much of their capacity had been offered below FPA-adjusted reference levels. The impact of above-cost offers on cleared capacity remained relatively limited—the "output gap" metric stayed below 2%.

2.1.1 C4 Concentration Ratio for Generation

Supplier market concentration among the largest firms controlling generation and scheduled import transactions is commonly measured by the "C4 "index, which represents the combined market share of the four largest firms. This metric is useful for tracking trends in supply concentration over time, as companies enter, exit, or consolidate their positions in the New England market.[97, 98] As shown in Figure 2-1 below, the C4 values in the real-time energy market remained within a narrow range and declined slightly during on-peak hours in 2024.[99]

Figure 2-1: Real-time System-wide Supply Shares of the Four Largest Firms



The metric is indicative of low levels of system-wide market concentration, particularly because the market shares are not highly concentrated in any one company. In 2024, about 40% of energy supply came from the four largest suppliers, with the distribution of energy across those suppliers being approximately equal.

[97] The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in on-peak hours of the year and accounts for affiliate relationships among suppliers.

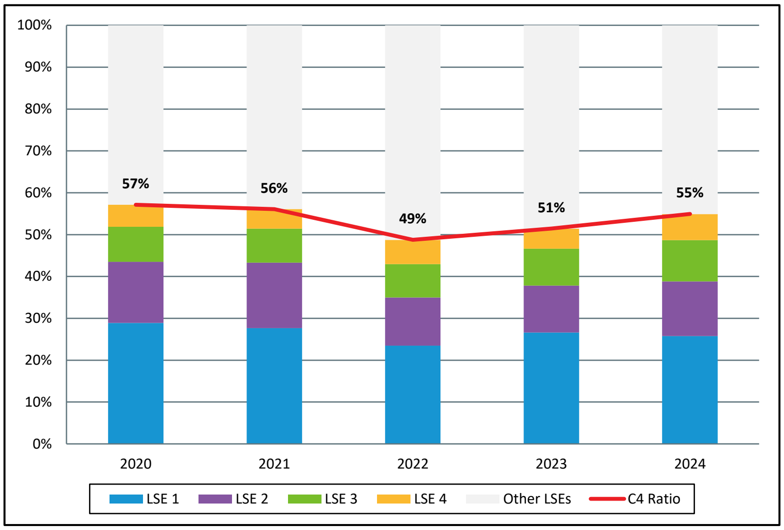
[98] The C4 analyses for both supply and demand do not account for market participants with both load and generation positions. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to raise prices to benefit their generation would come at a cost to their load position. Any actions that would suppress prices to benefit their load would come at a cost to their generation position.

[99] On-peak hours last from hour-ending (HE) 8 to HE 23 on non-holiday weekdays.

2.1.2 C4 Concentration Ratio for Load

The C4 index for load measures the market concentration among the four largest load-serving entities (LSEs) in the real-time energy market, and is presented in Figure 2-2 below.[100]

Figure 2-2: Real-time System-wide Demand Shares of the Four Largest Firms[101]



In 2024, the top four load-serving entities purchased 55% of the total (real-time) load position in New England, up from 51% in 2023.[102] However, there is no evidence to suggest that LSEs exhibited energy market bidding behavior consistent with the exercise of buyer-side market power (deflating price). On average, over 100% of demand cleared in the day-ahead market and the aggregate demand curve remained relatively price-insensitive around expected LMPs (see Section 3.3.2 on Demand Bidding).

[100]The C4 load metric accounts for affiliations among different LSEs and includes on-peak hours only. The metric uses Real-time load obligation (RTLO) to measure load. RTLO is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between RTLO and real-time generation obligation represents energy losses.

[101] The firms labeled "LSE 1", "LSE 2" and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

[102] The Load C4 ratio fell significantly in 2022 after one participant divested a large share of its generation and load into an independent company.

2.1.3 Residual Supply Index and the Pivotal Supplier Test

We apply two widely-used structural market power tests to indicate opportunities for participants to exercise market power in the real-time market: the pivotal supplier test (PST)[103] and the residual supply index (RSI).[104]

Day-Ahead Energy Market

Two versions of the PST are calculated for the day-ahead market: the traditional PST[105] and an alternative test based on available economic capacity, termed "Eco PST." Unlike the traditional approach, the Eco PST only includes capacity offered at or below a defined price threshold, excluding resources with clearly extramarginal offer prices.[106] This refinement acknowledges that such high-priced offers may not represent meaningful competitive pressure and are unlikely to contribute to keeping market prices within a reasonable range of expected outcomes.

Table 2-1 below, shows the percentage of hours with at least one pivotal supplier as calculated using the PST and the Eco PST for a price threshold equal to 1.5 times the nodal LMP.

[103] Pivotal suppliers are identified for every five-minute pricing interval by comparing the real-time supply margin to the sum of each participant's total supply that is available within 30 minutes. When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each year to obtain the percentage of intervals with pivotal suppliers.

[104] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier is needed to meet demand, and could potentially exercise market power (if permitted). Further, if the RSI is less than 100, there is at least one pivotal supplier. Conversely, when the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market. The data used to calculate the RSI come from the ISO's real-time market software (the Unit Dispatch System, or UDS). Based on these data, the RSI for an interval t is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

[105] Pivotal suppliers are identified for each hour by comparing each participant's total available supply to the supply margin. When a participant's available supply exceeds the supply margin, it is considered pivotal. Virtual capacity is excluded. The number of hours with a least one pivotal supplier is divided by the total number of hours in each year to obtain the percentage with pivotal suppliers.

[106] Eco pivotal suppliers are identified for each hour by comparing each participant's available capacity offered at or below a price threshold to the calculated supply margin at the same price threshold. Virtual capacity is excluded. The number of hours with a least one pivotal supplier is divided by the total number of hours in each year to obtain the percentage with pivotal suppliers. If a participant is Eco pivotal at a certain price threshold, the participant has the potential to exercise market power when a fraction of its capacity offered under a price threshold (P_0) is needed to meet the system requirements at P_0. An Eco pivotal supplier could withhold capacity and more expensive capacity, above P_0 will be needed to meet system requirements.

Table 2-1: Percentage of Hours with Pivotal Suppliers Under PST and Eco PST

Year	PST	Eco PST (1.5 * LMP)
2020	0.0%	0.1%
2021	0.2%	0.5%
2022	0.9%	0.3%
2023	0.1%	0.3%
2024	2.2%	3.8%

In 2024, tighter supply margins—driven by reduced availability of both imports and native supply—combined with relatively higher projected day-ahead load, led to an increase in the number of hours with both Eco Pivotal Suppliers and traditional Pivotal Suppliers. Notably, in 2022, the percentage of hours with pivotal suppliers was lower under the Eco PST metric than under the traditional PST. This outcome reflects the elevated energy prices that year, which discouraged exports and increased the availability of import capacity on a net basis, thereby enhancing the level of competitive supply included in the Eco PST calculation.

The number of hours with pivotal suppliers is lower in the day-ahead market than in the real-time market. There is more available supply to the system the day before the operating day, whereas in real time offline long-lead time resources are not included in the PST. In the real-time energy market, the clearing process is more constrained, and the market exposed to unexpected events that could result in sudden changes in available capacity and demand requirements.

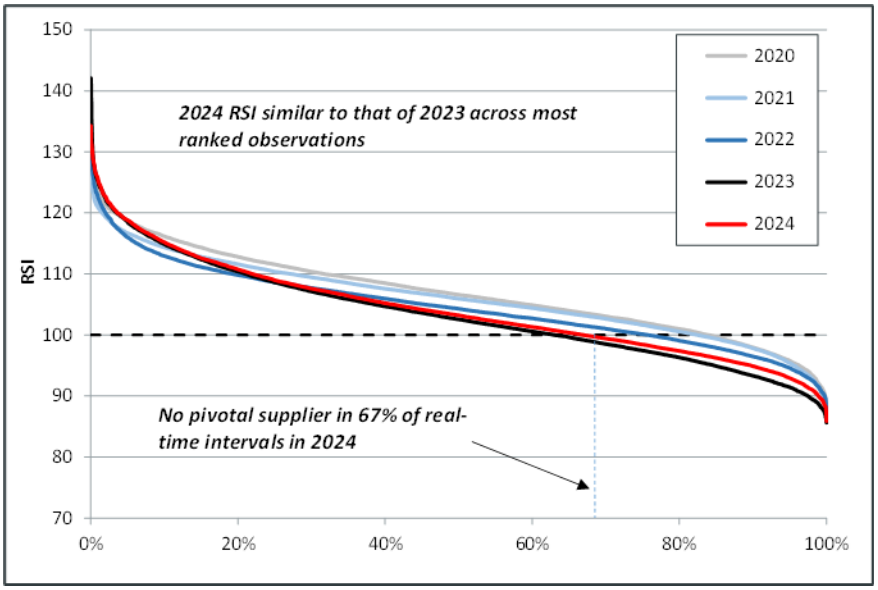
Real-Time Energy Market

The average RSI for all five-minute real-time pricing intervals and the percentage of five-minute intervals with pivotal suppliers are presented in Table 2-2 below. Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 2-3. The figure shows the percent of hours when the RSI was above or below 100 for each year, indicating the presence of at least one pivotal supplier.

Table 2-2: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2020	16.6%	106.9
2021	18.0%	106.0
2022	24.9%	104.6
2023	37.3%	103.5
2024	33.3%	104.2

Figure 2-3: System-wide Residual Supply Index Duration Curves



There were more five-minute intervals with pivotal suppliers in 2024 and 2023 than in any other year in the reporting period. This indicates that suppliers faced relatively less competition in these two years than during the three previous years. In 2023, the increase in the number of intervals with at least one pivotal supplier was driven by lower reserve margins that occurred due to multiple long-term planned outages at pumped-storage facilities. In 2024, the average reserve margin returned to a normal value. However, net imports were at their lowest levels of the reporting period, meaning that native generation made up a larger share of load. This resulted in two suppliers being pivotal frequently. As a result, the total percentage of intervals with at least one pivotal supplier was just slightly below that of 2023.

2.1.4 Day-Ahead and Real-Time Price-Cost Markups

In a perfectly competitive market, all market participants' energy supply offers would equal their marginal costs. The energy component of the LMP would then be set by the supply offer or demand bid on the margin. However, in practice, participants can raise their supply offers above marginal costs. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitments and dispatch, leading to inefficient market outcomes. Though the IMM administers mitigation rules in the energy market to prevent the exercise of market power, participants are allowed to increase their offers within a certain threshold before mitigation is applied.

The price-cost markup estimates the divergence of the observed market outcomes from the ideal scenario in which all energy supply is offered at marginal cost. The results provide insight into how uncompetitive offer behavior affects the energy markets. A larger price-cost markup means that a larger component of the LMP is the result of inflated supply offers. This analysis used different methods for the day-ahead and real-time price-cost markup calculations. For the day-ahead metric, IMM simulated the market clearing using supply offer and marginal cost scenarios.[107] [108] The real-time analysis calculated (load-weighted) LMPs by creating supply curves for 1) available generation[109] by offer price and 2) available generation by marginal cost estimate, and then intersecting real-time demand with each.

The annual price-cost markup values from the day-ahead simulation and real-time analysis are shown in Table 2-3 below.

Table 2-3: Energy Market Price-Cost Markup, %

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2020	0.9%	-3.1%
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%
2024	2.4%	6.8%

In 2024, the price-cost markup for the day-ahead energy market remained low at 2.4% but was higher than in the other years of the reporting period, which mostly saw negative values. This indicates that the average marginal resource offered slightly above marginal costs, and that offers deviating from marginal cost increased the generation-weighted day-ahead energy market price by approximately 2.4%. This result was higher than in previous years due to fewer instances of gas-fired generators offering *below* marginal costs. This is discussed further below.

In the real-time market, annual load-weighted markups were also close to zero or negative during 2020-2023, but increased to 6.8% in 2024. The increase was primarily due to the behavior of gas-fired generators, which has the largest impact on annual markup values in both markets. There were fewer instances of gas generators offering below their marginal costs in 2024 than in previous years, leading to higher average markups. Gas-fired generators often offer at values lower than their estimated marginal costs for multiple reasons, including managing gas burn to nominations or offering lower output levels below their fuel price-adjusted reference level.[110] In 2024, there was more gas generation than in 2023 (up by 472 MW on average) due to lower net imports, leading many gas generators to have higher average dispatch points in 2024. This likely led to fewer instances of generators clearing at prices well below their fuel price-adjusted reference levels, as we have seen in the past years.

[107] To calculate the day-ahead price-cost markup, the IMM used the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model to simulate the day-ahead market clearing using two scenarios: The offer case uses actual day-ahead energy market supply offers submitted by market participants. The marginal cost case assumes all market participants offered at an estimate of their short-run marginal cost. The price-cost markup is then calculated as the percentage difference between the annual generation-weighted LMPs for the offer case and the marginal cost case simulations.

[108] Prior to the 2022 Annual Markets Report, this metric used a different methodology to estimate marginal costs. This is why the values in this report are lower than values for the same years in previous reports.

[109] Available generation is equal to on-line generation plus generation capacity that can come on-line within 30 minutes. It comes from on-line generators (both long lead-time and fast-start) and off-line fast-start generators.

[110] In previous years, the most extreme negative markup values occurred during the winter months, when generators are more likely to have fuel price adjustments (FPAs) in place. FPAs are applied to the entire output curve and replace the default gas index value, but gas-fired generators often use FPAs to reflect the price of incremental gas needed at higher output levels, which might be higher than the market value of liquidating gas that they have already purchased.

Though the markup percentages in both markets were higher than in previous years, the figures still remained below the tightest mitigation threshold (10%). These results indicate that competition among suppliers in the day-ahead and real-time markets limited their ability to inflate LMPs by submitting offers above marginal cost.[111] In the 2022 AMR, the IMM recommended reviewing energy mitigation thresholds and reference level methodologies. Current mitigation thresholds allow considerable markups in supply offers and have been in place for many years with little empirical support. In this assessment, we also reviewed day-ahead price-cost markup values at an hourly level and compared the peak load hour price-cost markup with the forecasted supply margin at peak. Comparing these attributes provides insight into whether participants take advantage of tight system conditions, when market power tends to be more of a concern, by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2024, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present. We also reviewed real-time price-cost markup and reserve margin values at an hourly level. Despite outlier days with high markups and tight conditions, there was no significant correlation between margins and markups for the over the year.

2.1.5 Real-Time Economic Withholding

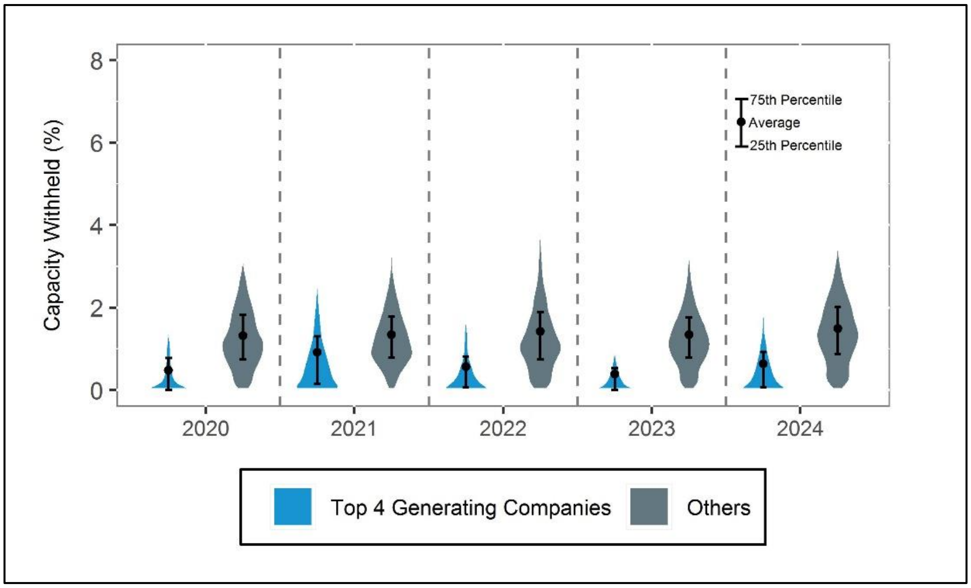
Economic withholding refers to suppliers offering their energy above cost. This action can lead to market harm if it results in higher prices that load must pay to purchase energy. Suppliers may engage in this type of behavior if they believe it could be profitable to their portfolio. However, the price impact of this action will depend on the competitiveness of the market. In more competitive markets, the price impact is more likely to be limited as there is often additional competitively-price supply that can clear. Mitigation, discussed in more detail in Section 2.2, can also limit the market impact of this action.

Hourly economic withholding (as a percent of capacity) during on-peak hours in each of the past five years is summarized in Figure 2-4 below.[112] Note the curves depict the distribution of hourly withholding, where the widest sections of each curve represent the most-frequently observed levels of withholding. Results are broken down for two groups: combined withholding by the top four generating companies (those with the largest share of generation) versus all others.

[111] Differences between the real-time and day-ahead price-cost markups values are due to several factors, including: 1) differences in the methodologies used to calculate the price-cost markup in each respective market; 2) modeling differences between the day-ahead and real-time energy markets; and 3) real-time events that the day-ahead market did not anticipate.

[112] We estimate the economically withheld capacity for each generator in every real-time interval as the difference between: a) the quantity that was economic (i.e., the sum of MWs where marginal cost ≤ LMP) and, b) the actual quantity offered (i.e., the sum of MWs where offer price ≤ LMP). In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers only non-fast-start generators that are online and all fast-start generators (online or offline), and it does not assess potential withholding by offline, non-fast-start generators.

Figure 2-4: Hourly Real-time Economic Withholding During On-Peak Hours



In 2024, economic withholding was relatively low across both groups (on average below 2%) and generally in line with levels seen in prior years. Although not presented in the figure, levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers were largely unable or did not attempt to take advantage of tight system conditions by economically withholding.

2.2 Energy Market Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[113] Under certain conditions, the IMM will mitigate generator supply offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values.[114]

Here, we review the level and underlying drivers of the various forms of energy market mitigation in the day-ahead and real-time energy markets.

[113] This review of supply offers is automated (along with the offer mitigation process) and occurs within the ISO's energy market software.

[114] The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs. Seven mitigation types utilize mitigation tests and are used in ex-ante supply offer mitigation. An eighth mitigation type for dual-fuel generators is performed after-the-fact, when a dual-fuel generator burns a low-priced fuel but submits supply offers based on a higher-cost fuel.

Key Takeaways

Supply offer mitigation remained low in 2024. There were 548 asset hours of mitigation, representing just 0.03% of all asset hours subject to mitigation, a level similar to 2023 (460 asset hours). This outcome is consistent with the system-level competitiveness metrics discussed above, as well as the limited instances of localized market power (e.g., in import-constrained areas or due to local reliability commitments).

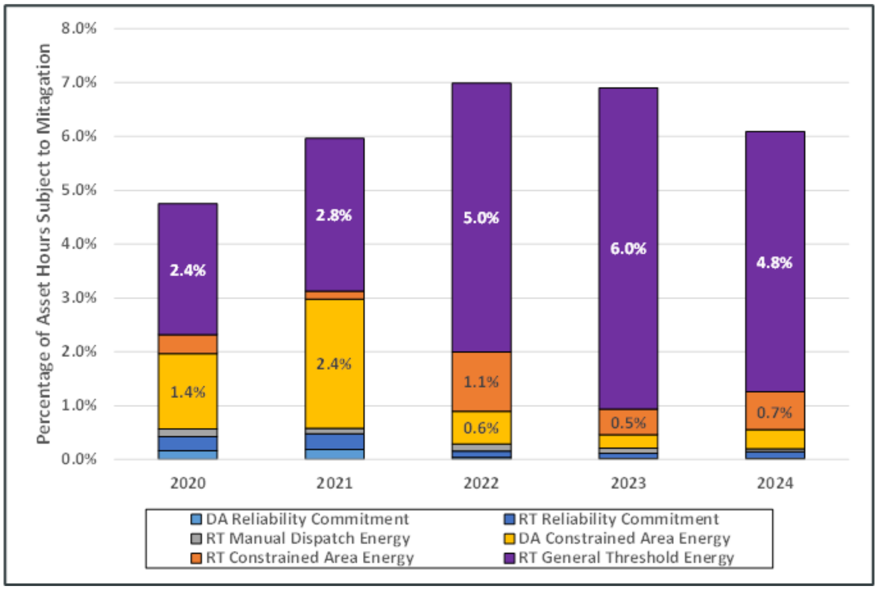
We continue to emphasize the importance of strengthening mitigation rules to ensure their robustness under a range of competitive conditions. In prior reports, we issued several recommendations, which can be categorized as follows:

- Review of conduct and impact tests and thresholds, including the exemption for non-capacity resources from day-ahead mitigation.
- Enhancements to indicators of structural market power, both at the system level and for localized areas.
- Improvements to the accuracy of reference level calculations, with a focus on greater reliance on cost-based reference levels. We also supported the FERC-approved proposal to introduce MW-dependent Fuel Price Adjustments, which will better capture variations in natural gas costs based on quantity.

A structural test serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours in which a structural test failure occurred from 2020 to 2024 is shown in Figure 2-5 below.[115]

[115] A structural test failure depends on the type of mitigation analyzed. The definitions of the structural test applied in general threshold and constrained area mitigation can be found in *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.2, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. The conditions to pursue manual dispatch energy and reliability commitment mitigation are found in Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

Figure 2-5: Energy Market Mitigation Structural Test Failures

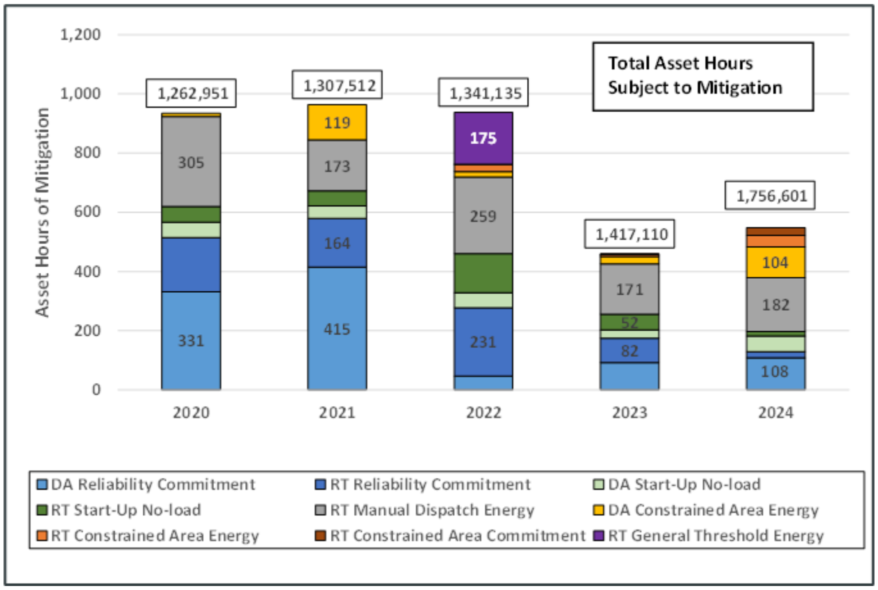


In 2024, the total asset hours subject to mitigation reached 1.76 million asset hours, in which approximately 107,000 asset hours (6.1%) failed structural tests.[116] The structural test for general threshold energy mitigation fails the most often and triggers any time a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 2-6 along with the total amount of asset hours subject to mitigation (white boxes).

[116] The asset hours subject to mitigation are estimated as a committed generator with an economic dispatchable range at or above its economic minimum (eco min). Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

Figure 2-6: Energy Market Mitigation Asset Hours



In 2024, there were 548 asset hours of mitigation or just 0.03% of all asset hours subject to mitigation , a similar value to that of 2023 (460 asset hours).[117]

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. Day-ahead and real-time constrained area mitigations occurred more frequently in 2024, with 104 and 65 asset hours of mitigation, respectively. In the day-ahead market, most constrained area energy mitigations occurred in December due to binding constraints on the North-East New England Import Interface resulting from planned transmission line outages. The real-time constrained area commitment and energy mitigations occurred across several different days and assets throughout the year.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.[118] In 2024, reliability commitments totaled 408 asset hours in the day-ahead and 2,153 asset hours in the real-time markets, in which the majority of asset hours (238 in day ahead, 1,917 in real time) occurred in the Southeastern Massachusetts load zone. Reliability commitment mitigations reached 129 asset hours in 2024, or just 5% of reliability commitment asset hours.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in

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[117] For more information on Energy Market Mitigation types and thresholds, see *An Overview of New England's Wholesale Electricity Markets: A Market Primer* (June 2023), Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

[118] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. See *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

very high uplift.[119] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In 2024, only three participants were associated with the 68 asset hours of SUNL commitment mitigation.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs with the least frequency of all mitigation types. Across the reporting period, over 60,000 asset hours of pivotal supplier energy was subject to mitigation each year on average; mitigation has occurred for only 175 asset hours, all in 2022. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with four participants accounting for 76% of the structural test failures in 2024.

Manual dispatch energy (MDE) mitigation: The ISO will assign manual dispatch points to utilize flexible generation in addressing short-term issues on the transmission grid. As a result, gas or dual-fuel generators receive manual dispatches most often, accounting for 87% of the 992 asset hours of manual dispatch in 2024. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than any other mitigation type, reaching a total of 182 asset hours in 2024.

We continue to emphasize the importance of reviewing and improving mitigation rules to ensure their robustness under changing competitive conditions. To that end we have issued a number of recommendations in prior reports, which are summarized in the Executive Summary and can be categorized as follows:

- Review of conduct and impact tests and thresholds, and the day-ahead mitigation exemption for non-capacity resources.

- Improved indicators of structural market power at a system level (accounting for company affiliations, generator ramping) as well as for local market power (export-constrained areas).

- Improvements to the accuracy of reference level calculations, such as prioritizing reliance on cost-based reference levels. During 2024, we supported the ISO's proposal to introduce MW-dependent Fuel Price Adjustments (FPAs), which will reflect that natural gas costs can vary by quantity, and which FERC ultimately approved.[120]

[119] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters).

[120] See the FERC filing regarding MW-dependent FPAs, *Order accepting tariff revisions, terminating show cause proceeding, and directing informational filing*, (Issued November 21, 2024), available at: https://www.iso-ne.com/static-assets/documents/100017/er24-2584_el23-62_order_accept_revisions_terminate_show_cause_direct_info_filing.pdf Also see *Comments of the Internal Market Monitor on Fuel Price Adjustment Modifications*, available at: https://www.iso-ne.com/static-assets/documents/100014/imm_comments_on_mw-adjusted_fpas.pdf

2.3 Financial Transmission Rights Market

In this section, we look at the competitiveness of the Financial Transmission Rights (FTR) market, with a specific focus on market concentration. In this context, market concentration refers to the extent to which FTR MWs are concentrated among market participants.

Key Takeaways

Ownership of FTR paths was relatively concentrated in 2024, with the top four participants holding over 60% of FTR capacity. High concentration levels have been observed in all five years covered in this report. However, the FTR market remained fairly active in 2024 with over 30 unique participants bidding in the auctions over the course of the year.

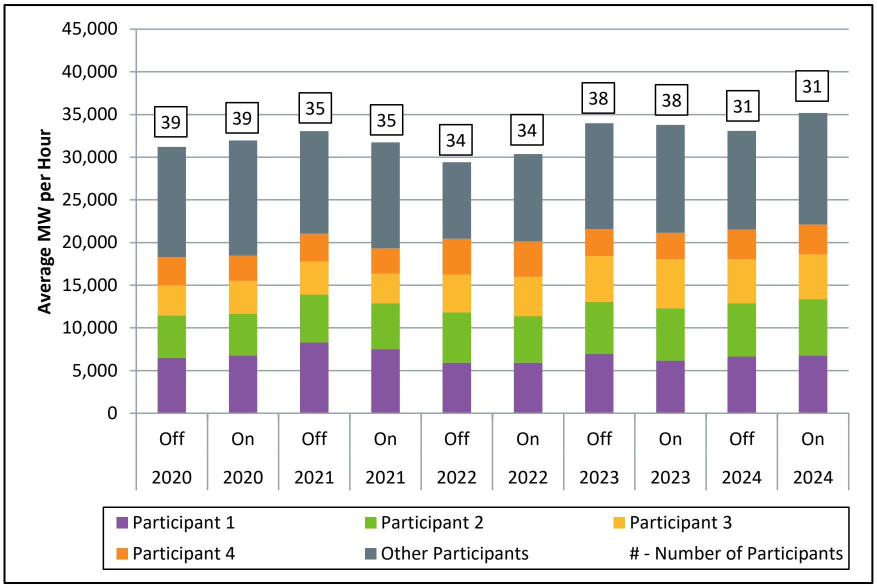
As discussed in Section 8.2.3, FTR profitability in 2024 was moderate ($1.5 million), although this total was dragged down by heavy losses (-$6.8 million) associated with FTRs that source from .I.ROSETON 345 1 ("Roseton"), ISO-NE's external node for trading across the New York - New England ("NYNE") interface. Unlike in 2023, the top four largest holders of FTRs in 2024 were all profitable.

Determining what constitutes a competitive level of FTR ownership is complex, as it is unlikely to align with system-level shares of load-serving or generation ownership. This is because there are not clear commercial reasons for all market participants to hold FTR positions (e.g., participants that serve load or own generation in unconstrained areas). Even those participants that may benefit from hedging basis risk can have risk preferences that favor exposure to day-ahead congestion over managing that exposure with the purchase of a FTR. Further, FTR market design permits the purchase of FTRs for financial speculation, so many FTR holders have no load or generation position at all.

The concentration of FTR MWs among market participants in 2024 was similar to prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each year is shown in Figure 2-7 below.[121] This figure also shows the number of different participants that held FTRs each year (indicated by the number above each stacked column). This information is broken down separately for the on-peak and off-peak periods.

[121] The firms labeled "Participant 1," "Participant 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

Figure 2-7: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



The top four participants held 63% of on-peak FTR MWs and 65% of off-peak FTR MWs in 2024. The concentration ratio of the top four FTR holders has stayed relatively stable over the reporting period, ranging between 58%-69%. However, the total number of unique FTR holders decreased modestly in 2024 relative to prior years. In 2024, there were only 31 unique participants in both the on-peak and off-peak periods. The number of unique participants had ranged between 34-39 participants in the four years prior to that.

2.4 Ancillary Services

Below, we review the competitiveness of the Forward Reserve Market (FRM) auctions and the regulation market. The first subsection (2.4.1) provides Residual Supply Index (RSI) results for the last 10 FRM auctions. The second subsection (2.4.2) reviews available regulation capacity relative to the regulation requirement and indicates the RSI for 2024.

Key Takeaways

We observed increased competitiveness in the two FRM auctions that took place in 2024 relative to 2023, with RSI values for all system-wide reserve requirements at structurally-competitive levels.

Meanwhile, the regulation market continued to be structurally competitive in 2024 with available supply significantly exceeding the regulation requirement and no supplier controlling enough supply to potentially have market power.

2.4.1 Forward Reserve Market

The competitiveness of the FRM is assessed using the RSI and is based on FRM offer quantities by participant and the forward reserve requirements in each auction. The heat map provided in

Table 2-4 Table 2-3:below shows the offer RSI for the TMNSR requirement and the "total thirty-minute" reserve requirement at the system level.[122,123]

Table 2-4: Offer RSI in the FRM for the TMNSR and the Total Thirty-Minute Requirements[124]

Procurement Period	TMNSR (System)	Total Thirty-Minute (System)
Summer 2020	84	97
Winter 2020-21	102	115
Summer 2021	92	108
Winter 2021-22	110	116
Summer 2022	78	90
Winter 2022-23	109	112
Summer 2023	81	86
Winter 2023-24	82	88
Summer 2024	107	103
Winter 2024-25	106	102

Both the Summer 2024 and Winter 2024-25 auctions had structurally-competitive levels of supply for both FRM requirements.[125] Prior to this, structural market power had been observed in many of the recent FRM auctions, which was one of several factors that led the IMM to recommend that the forward reserve offer cap price be reviewed and updated.[126] This Tariff-specified cap is the only constraint for potentially uncompetitive supply offers in forward reserve auctions, as the IMM does not have the authority to perform cost-based reviews nor to mitigate uncompetitive offers. The ISO acted on this recommendation with proposed rule changes and these changes were approved by FERC in April 2024.[127]

2.4.2 Regulation Market

We reviewed the competitiveness of the regulation market by examining market structure and resource availability. The abundance of regulation resources and the relatively unconcentrated

[122] The "total thirty-minute" reserve requirement considered in this section is the sum of the TMNSR and TMOR FRM requirements as discussed in Section 7. The RSI for TMNSR is based on the total quantity of TMNSR offers, excluding the largest TMNSR offer quantity by a single market participant. The RSI for the total thirty-minute requirement is computed similarly. Given that TMNSR can also satisfy the total thirty-minute requirement, the TMNSR offer quantity and the TMOR offer quantity are combined to determine this value.

[123] No zonal values are shown as there were no zonal reserve requirements during the reporting period.

[124] The colors indicate the degree to which structural market power was present; red is associated with low RSIs, white with moderate RSIs, and green with high RSIs. Dark red indicates that structural market power was present, while dark green indicates that there was ample offered supply without the largest supplier.

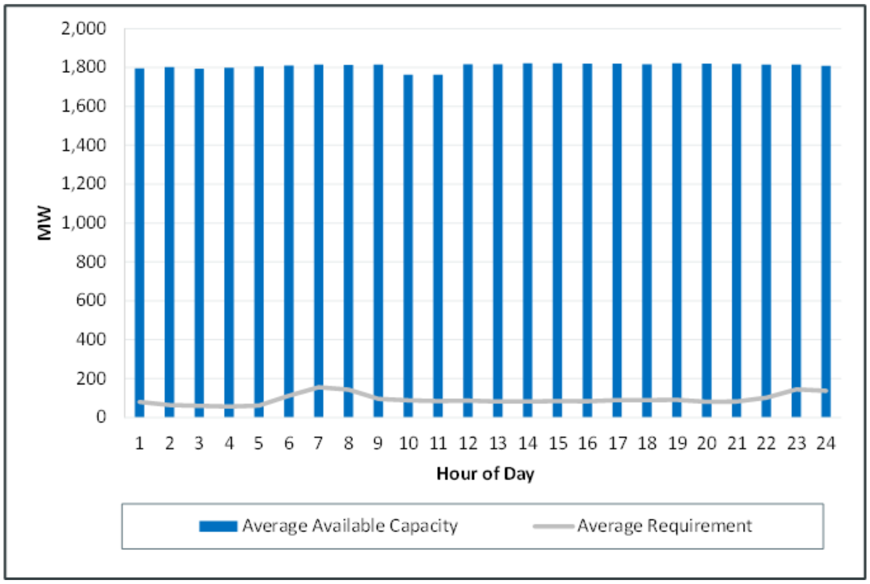
[125] As mentioned in Section 2.1.3, RSI values above 100 indicate that the reserve requirement could still be satisfied without the offers from the largest supplier, limiting the ability of that supplier to potentially exercise market power.

[126] For our recommendation related to the forward reserve offer cap, see our *Spring 2023 Quarterly Markets Report* (August 1, 2023), pp 47-51, available at https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

[127] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap*, ER24-1245-000 (April 12, 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf.

control of that supply reduces any opportunity to engage in economic or physical withholding, as indicated in Figure 2-8 below.

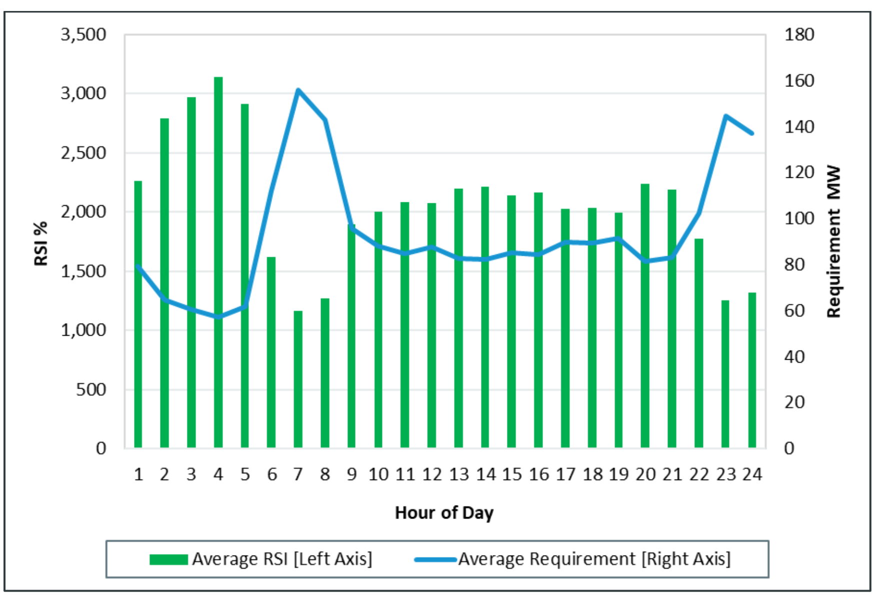
Figure 2-8: Average Regulation Market Requirement and Available Capacity, 2024



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an abundance of available supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The RSI provides a better indicator of the structural competitiveness of the regulation market. As shown in Figure 2-9, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 2-9: Average Regulation Requirement and Residual Supply Index, 2024



In 2024, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system had the capability to serve ten times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirements. Accordingly, we find the regulation market was competitive in 2024.

Section 3
Day-Ahead and Real-Time Energy Market

We examine key trends and drivers of energy market outcomes in this section, which is structured as follows:

- Day-ahead and real-time energy prices across a number of dimensions, including location, time-of-day, and convergence (3.1)
- Factors that influence supply and demand participation (3.2 & 3.3)
- Energy markets and system reliability interactions (3.4)
- Net commitment period compensation (NCPC) payments (3.5)
- Summary of system events in 2024 (3.6)[128]
- Demand response resource (DRR) participation in the energy markets (3.7)

Day-ahead and real-time energy prices increased in 2024 (11%-13%) from 2023 levels. Day-ahead and real-time energy prices increased moderately in 2024 (11%-13%) from 2023 levels. This outcome reflects an increase in emissions costs, as well as a greater reliance on natural gas-fired generators due to fewer net imports, as well as dispatch in more expensive upper ranges of gas-fired capacity during hot summer conditions.

In addition to generation costs, other factors influenced energy market outcomes in 2024. Noteworthy system events included a deficiency of operating reserves on June 18 and August 1, which produced high energy and reserve prices and 2.33 hours of capacity scarcity conditions. DRRs continued to be infrequently dispatched in 2024 because of their high offer prices.

NCPC payments totaled $35 million in 2024, similar to 2023, and, as a percentage of total energy payments, remained low at 0.6%. Real-time payments to units committed to meet load and reserve requirements continued to drive the majority of NCPC payments.

3.1 Energy Prices

Below, we evaluate energy prices across a number of dimensions, including by energy market (i.e., day-ahead and real-time), time-of-day, and location. These perspectives offer useful context for understanding differences in energy prices (LMPs) over the review period. The first subsection (3.1.1) summarizes energy market pricing over a five-year period, reviews price separation across load zones, and examines load-weighted LMPs, which provide an indication of the effective prices that load-serving entities pay for energy. The second subsection (3.1.2) looks at pricing trends as levels of renewable generation rise. The third subsection (3.1.3) estimates the impacts of fast-start pricing rules on LMPs and other market outcomes. Finally, the third subsection (3.1.4) examines the extent to which prices converged across the day-ahead and real-time energy markets —an important indicator of market efficiency.

[128] For a detailed assessment of system events, see our *Quarterly Markets Reports*, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor

Key Takeaways

Price Levels and Drivers: Energy market prices increased by more than 10% in 2024 relative to 2023. The price increases reflected higher emissions costs, as well as a reduction in typically low-cost net imports from Canada. Overall, prices were consistent with observed market conditions, including input fuel costs, load levels, and generator operations.

- The annual simple average Hub price was $41.47/MWh in the day-ahead market, up 13% from 2023, and $39.50/MWh in real time.
- Day-ahead and real-time Hub prices were comparable on average, indicating that the day-ahead market performed reasonably well in predicting expected real-time outcomes; the day-ahead energy price at the Hub exceeded the real-time price by an average of $1.93/MWh in 2024.
- There was minimal congestion in 2024. When congestion did manifest, the Connecticut load zone tended to have the lowest average LMPs while the Northeastern Massachusetts (NEMA) load zone had the highest average prices.

Fast-Start Pricing: The fast-start pricing rules in the real-time market are generally achieving their key design objective of improving price formation by better reflecting the production costs of flexible, fast-start resources in energy prices and reducing uplift payments. However, there continued to be significant periods of non-zero reserve pricing and payments even when reserve constraints were not impacting the physical dispatch of resources and there was a physical surplus of reserves. We continue to recommend that the ISO assess this issue.

Expected Trends in Pricing with Increasing Levels of Renewable Generation: An assessment of anticipated pricing trends with increased renewable generation indicates a muted effect to date, but is likely to ramp up over the next few years**.**

- **Negative real-time prices** remained infrequent in 2024, occurring in just 0.35% of five-minute intervals at the Hub and load zones, and 0.40% at the nodal level. Currently, periods of negative pricing are relatively short-lived. For context, the Pathways Study indicated that negative prices could occur in 33% of hours by 2040 under the current energy market structure.
- **Price volatility** has been increasing slightly over time, consistent with the growth in intermittent resources—particularly solar generation—which has contributed to lower midday loads and steeper evening ramps.
- The **volume of generation offered at negative prices** has remained relatively steady over the past five years, ranging from 1,390 MW to 1,495 MW on average per hour, representing about 10% of the overall energy market supply.

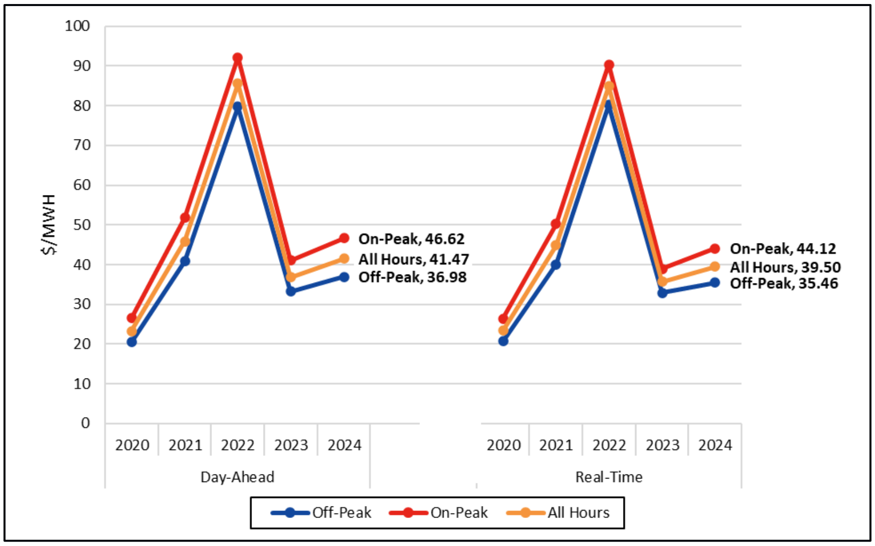
3.1.1 Day-Ahead and Real-Time Energy Price

Day-ahead and real-time energy prices at the Hub and the eight New England load zones are presented below. These prices are evaluated across a number of dimensions: time-of-use (e.g., peak, off-peak hours), location, and load-weighting.

Hub Prices by Time-of-use and Market

First, Figure 3-1 shows simple average Hub prices in the day-ahead and real-time markets for three time tranches: all hours, peak, and off-peak hours.[129]

Figure 3-1: Annual Simple Average Hub Price



Average Hub prices in 2024 increased relative to 2023, driven by changes in input costs, shifts in the supply mix, and higher prices during peak summer demand periods. In 2024, the simple annual average Hub price (in *all hours*) was $41.47/MWh in the day-ahead market and $39.50/MWh in the real-time market. These prices represent increases over prior year averages of 13% and 11%, respectively. Time-of-day pricing in 2024 (i.e., on-peak and off-peak) followed a similar upward trend.

Typically, increases in energy prices in New England are driven primarily by higher natural gas prices. However, this was not the main driver in 2024; natural gas prices were effectively unchanged, on average, from their 2023 levels. One key driver of this change in energy prices was emissions costs. As discussed in Section 1.2, the cost of CO_2 emissions allowances increased in 2024, raising the cost to produce energy with fossil fuel-fired generators. In addition, reduced levels of low-cost imports from Canada throughout the year, along with hot temperatures and stressed system conditions in the summer, contributed to the increase in average prices.

Prices by Load Zone and Market

At the *zonal* level, price differences were small in 2024 in both the day-ahead and real-time energy markets. Load zone prices were quite close to the Hub price, with an absolute average price difference between the Hub and zones of $0.38/MWh the day-ahead market and $0.35/MWh in real time, reflective of a system that is generally uncongested. As in prior years, the Connecticut load zone had the lowest average LMPs in both day ahead and real time (roughly $1/MWh less than the corresponding Hub prices), while the Northeastern

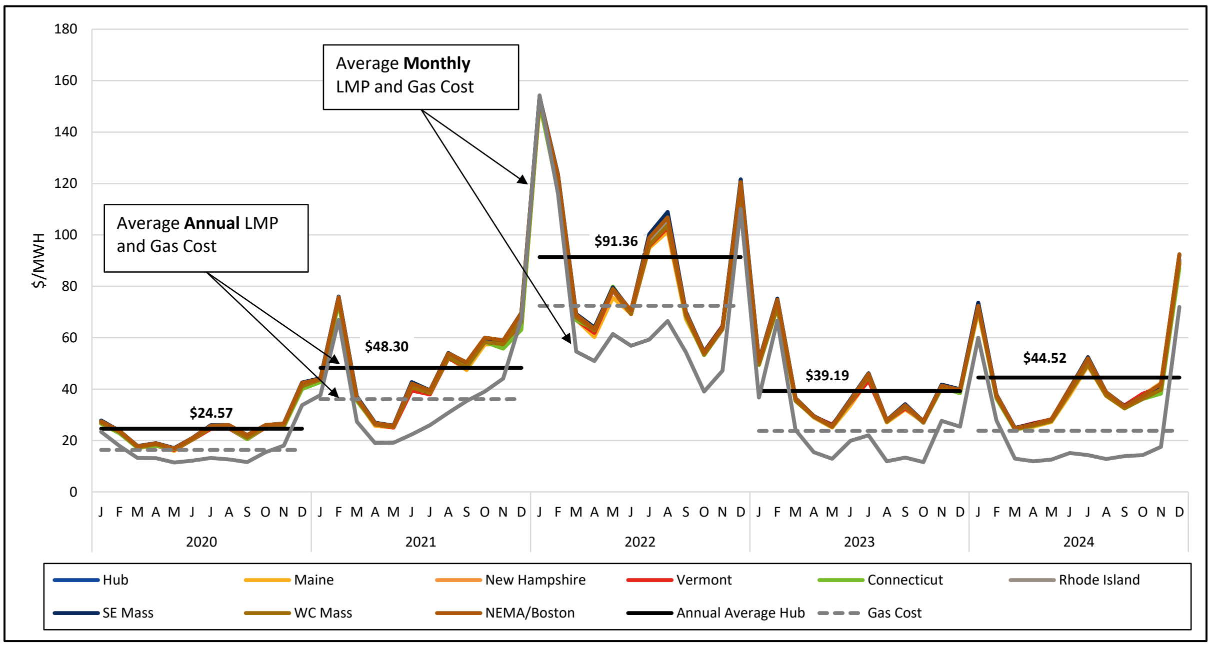
[129] On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC) holidays); the off-peak period encompasses all other hours.

Massachusetts (NEMA) load zone had the highest average prices (roughly $0.5/MWh higher than the corresponding Hub prices).

Consumer Prices: Load-Weighted Prices

Compared to simple average prices, load-weighted prices provide a more accurate measure of the average energy costs faced by load-serving entities (LSEs). Because energy consumption varies significantly by hour, load-weighted prices better capture the cost of meeting demand during peak periods, when higher consumption requires dispatching more expensive generation resources. As a result, load-weighted prices are typically higher than simple averages. In 2024, the average load-weighted prices were $44.52/MWh in the day-ahead market and $42.47/MWh in the real-time market. Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-2 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility.

Figure 3-2: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2020 to 2024 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Winter periods with high fuel prices and summer months with elevated load variability typically have the highest load-weighted prices; a similar trend applies to the real-time market. The effect of natural gas prices in 2024 is evident in the figure above, with day-ahead LMPs highest in January and December of this year during these cold winter months when gas demand was high.

3.1.2 Expected Pricing Trends with Increasing Levels of Renewable Generation

The states' decarbonization goals will require a significant increase in renewable generation over the next two decades. Several long-term ISO studies—including the Pathways to the Future Grid and the Economic Planning for the Clean Energy Transition (EPCET) study—

highlight a range of potential wholesale market pricing impacts associated with this transition.[130, 131] These include more frequent periods of negative energy prices driven by supply-side bidding behavior, as well as increased price volatility. This has implications for price formation and also revenue adequacy, with a potential shift of revenue dependency for some resources to the capacity market.

Because many renewable resources are compensated for their real-time output through prices specified in Power Purchase Agreements (PPAs) and are willing to clear at negative prices, this puts downward pressure on energy clearing prices. The EPCET study assessed how extended periods of negative LMPs could impact revenues of baseload resources, which cannot ramp down quickly due to operational constraints.[132] Further, as renewable generation grows, extreme "duck curve" days may occur where midday loads drop below baseload generation production levels, particularly nuclear generation, resulting in constrained renewable output and operational challenges.

While the pace of renewable generation additions has been relatively modest over the past five years (see Section 1.5) relative to the scale needed to meet state targets, it is still valuable to assess whether some of these anticipated pricing dynamics are beginning to emerge in today's market, and to revisit this assessment on a regular basis.

Negative Prices

The frequency of negative LMPs at the Hub, zones, and nodes remains very low with no clear trend emerging over the past five years. Table 3-1 below presents statistics for this period.

Table 3-1: Percentage of Five-Minute Intervals with Negative Real-Time Prices

Year	Negative Hub LMPs	Negative Zonal LMPs	Negative Nodal LMPs
2020	0.24%	0.28%	0.38%
2021	0.27%	0.28%	0.42%
2022	0.46%	0.46%	0.56%
2023	0.34%	0.34%	0.39%
2024	0.35%	0.35%	0.40%

Negative real-time Hub LMPs are relatively infrequent, occurring for just 0.35% of five-minute intervals at the Hub and load zones in 2024, and for 0.40% of intervals at the nodal level. While these figures have grown slightly since 2020, the range over the reporting period was relatively tight. For context, the Pathways Study indicated that negative prices might occur in 33% of hours by 2040 under the current energy market construct (versus 1% with net carbon pricing).[133]

[130] See the Analysis Group's *Pathways Study* (April 2022), available at https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf

[131] See the ISO's *Economic Planning for the Clean Energy Transition* report (October 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf.

[132] The *EPCET report* linked in the previous footnote discusses how negative LMPs and low loads could impact baseload resources in the following report sections: 1.6.2 Effect of Deep Decarbonization on Energy Markets, and 1.8.1 Challenging Minimum Load Conditions.

[133] *Pathways Study*, Table VI-2 Summary Statistics for Energy Market LMPs by Policy Approach, 2040.

In addition to considering the frequency of negative LMPs, we also assessed the duration of negative prices. Negative prices may ultimately be relatively short-lived depending on the extent to which market participants can respond by increasing exports, reducing generation down, or charging storage resources—the latter capability is expected to expand significantly in the coming years. Statistics on the duration of negative real-time LMPs are shown in Table 3-2 below.

Table 3-2: Negative Real-Time Hub LMP Durations, in Minutes

	Mean Duration	Median Duration	Mode Duration	Max Duration
2020	21	15	10	75
2021	23	15	10	120
2022	24	15	5	190
2023	17	15	10	85
2024	17	10	10	105

The median duration of negative real-time Hub LMPs ranged from 10 to 15 minutes over the reporting period, indicating that periods of negative pricing are currently relatively short-lived.

Price Volatility

Currently, combined-cycle gas generators are the dominant price-setting technology in the market. As a result, price variations largely reflect changes in natural gas costs, efficiency differences among combined-cycle units, and the higher costs associated with committing fast-start resources during peak periods. In the future, renewable generation is expected to set prices more frequently—often at negative levels. When conventional dispatchable resources are needed during periods of high demand or when the availability of weather-dependent resources declines, price swings are likely to become more pronounced. Consequently, price volatility is expected to increase.

To assess price volatility, we calculated the standard deviation of real-time and day-ahead Hub LMPs by year in Table 3-3 below. The standard deviation shows how widely prices are distributed compared to the average.

Table 3-3: LMP Volatility by Year

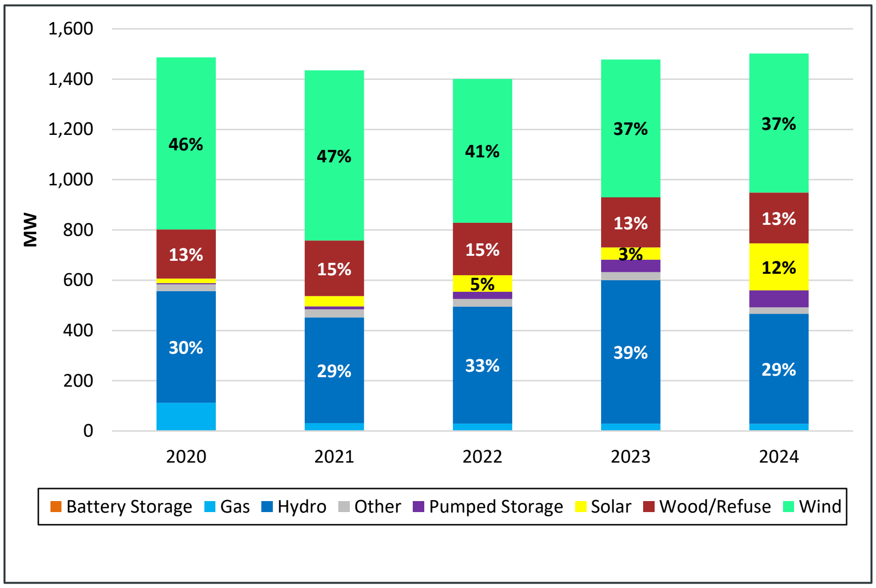
Year	Mean, RT Hub LMP	Standard Deviation, RT Hub LMP	Mean, DA Hub LMP	Standard Deviation, DA Hub LMP
2020	$23.38	$16.35	$23.32	$11.72
2021	$44.84	$29.06	$45.92	$23.89
2022	$84.92	$67.30	$85.55	$49.33
2023	$35.70	$37.66	$36.82	$26.22
2024	$39.50	$44.76	$41.47	$30.31

The standard deviation values show that volatility was lowest in 2020, which saw historically low natural gas and energy prices, and highest in 2022, which saw the highest natural gas prices and LMPs of the period. This change in the load shape results in low midday LMPs, but high LMPs over steep evening ramps, increasing price volatility.

Negative Energy Supply Offers

Figure 3-3 shows hourly average supply offered at negative prices in the real-time market, by fuel type. Note that the solar category only includes metered solar generators, as settlement only generators (SOGs) do not participate in the energy market.

Figure 3-3: Average Output Offered At Negative Values, Real-Time



The volume of generation offered at negative prices was relatively steady over the five-year period, and ranged from about 1,400 MW to 1,500 MW on average. This represents about 10% of the overall energy market supply. The composition of fuel types clearing at negative prices has shifted over time. Notably, the volume of wind generation offered at negative prices declined in the latter years of the period. By contrast, hydro accounted for a larger share of negative offers in 2023, while negative solar offers increased in 2024. These trends align with broader changes in the supply mix. Specifically, hydro generation was higher in 2023 due to favorable water levels, and average output from metered solar resources grew from 237 MW in 2020 to 525 MW in 2024.

3.1.3 Fast-Start Pricing: Impact on Real-Time Outcomes

The fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs. The purpose of fast-start pricing rules is to improve energy price formation when fast-start units are operating. Fast-start pricing rules allow LMPs to better reflect the marginal cost of fast-start resource deployment and, therefore, send more transparent short- and long-term market signals about the cost to operate the system.

We find that fast-start pricing is generally meeting the design's key objective of improving real-time price formation by better reflecting the production costs of flexible fast-start resources in energy prices.[134] In 2024, fast-start pricing impacts were similar to prior years. There continued to be significant periods of non-zero pricing (and payments) during times when the reserve constraint was not impacting the physical dispatch of resources and there was a physical surplus of reserves. We recommended that the ISO assess this issue in our 2022 Annual Report.[135]

Table 3-4 below compares a number of actual and estimated counterfactual market outcomes. The column labeled *Fast-Start Pricing* details actual pricing and settlement outcomes. The column labeled *Non-Fast-Start Pricing* provides estimates of counter-factual outcomes if fast-start pricing had not been implemented.

Table 3-4: Fast-Start Pricing Outcome Summary, 2024

Market Outcome	Fast-Start Pricing (Actual Outcomes)	Non Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP ($/MWh)[136]	$39.38	$37.09	**$2.29 (6%)**
Real-Time Energy Payments ($, Millions)[137]	$70.2	$58.9	**$11.3 (19%)**
NCPC Payments ($, Millions)[138]	$21.2	$29.7	**-$8.5 (-29%)**
Reserve Prices ($/MWh)[139]	$1.68	$0.90	**$0.78 (87%)**
Real-Time Reserve Payments ($, Millions)[140]	$26.5	$11.7	**$14.8 (126%)**
Percent of Intervals with Reserve Pricing (%)	8.1%	5.0%	**3.2% (64%)**
Intervals Fast-Start Resource Marginal[141]	25.5%	11.0%	**14.5% (132%)**

To summarize the key takeaways, the fast-start pricing mechanics:

- resulted in a higher frequency of fast-start resources setting price, mostly driven by pump-storage unit price-setting frequency (+5.5% from pump-storage demand, +7.3% from pump-storage generation, and +2.7% from non-pump storage demand)

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134 For more detail on fast-start pricing, see our *Summer 2017 Quarterly Markets report* (December 20, 2017), Section 5.5, available at https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

135 A summary of this and other recommendations can be found in the executive summary of this report.

136 The system LMP shown here is the energy component of the LMP in each interval.

137 This value is different than the real-time payments value reported in the wholesale cost section of the report because, here, real-time load deviations are only considered for locations and customers with physical load (i.e., exports and day-ahead demand that does not correspond to physical load are excluded).

138 NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments for generators and asset-related demand resources (ARDs). Due to data limitations, counterfactual LMPs were not available in every interval so estimated payments are slightly less than actual payments. Actual payments (i.e., not based on IMM estimates like the data shown in the table) in 2024 were $21.5 million.

139 These reserve prices represent the average reserve price in every interval – including $0/MWh reserve price intervals.

140 The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments. For more information on the impact of fast-start pricing on reserves, see Section 3.1.3.

141 This metric represents the percentage of intervals in which at least one fast-start generator was marginal (i.e., set price).

- increased the average annual system LMP by 6% and increased real-time energy payments by 19%,
- decreased real-time NCPC paid to generators and asset-related demand (ARDs) by 29%[142], and
- had a substantial impact on reserve pricing and payments, with non-zero pricing occurring in 64% more intervals. Overall, average reserve prices were 87% higher in the fast-start-pricing case than in the non-fast-start-pricing case, and payments were 126% higher.

3.1.4 Energy Price Convergence

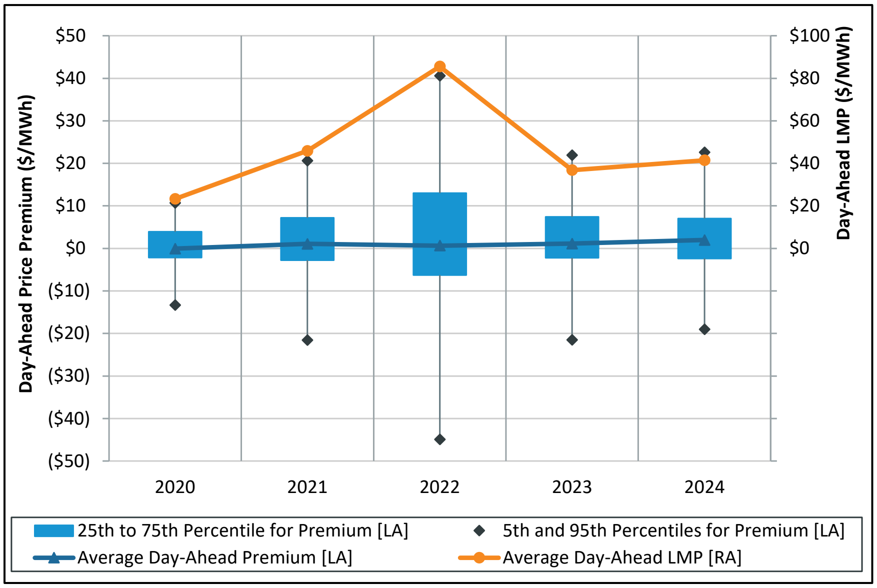
Price convergence refers to the extent to which prices aligned between the day-ahead and real-time energy markets. Price convergence can serve as a metric for market efficiency – which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. One way to assess price convergence is to look at the difference between day-ahead and real-time prices (i.e., the day-ahead price premium).[143] In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices. While day-ahead prices will almost never perfectly match real-time prices in any given hour (because real-time conditions will usually differ from expectations), one might expect to see similar average prices between the two markets over time.

Convergence Across all Hours

The average day-ahead price premium at the Hub in 2024 remained in line with recent historical values. This can be seen in Figure 3-4, which shows the distribution of the day-ahead price premium at the Hub between 2020 and 2024 using a box-and-whiskers diagram.[144] This figure also shows the average annual day-ahead Hub LMP (orange line).

[142] Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit and dispatch-out-of-merit NCPC to generators that did not recover their costs when following ISO dispatch instructions by 41%. The decrease was offset by an increase in Rapid Response Pricing Opportunity Cost (RRPOC) NCPC.
[143] The day-ahead price premium is defined as the day-ahead energy price *minus* the real-time energy price.
[144] The day-ahead price premium is measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

Figure 3-4: Average Annual Day-Ahead Price Premium at the Hub and Average Day-Ahead Hub LMP



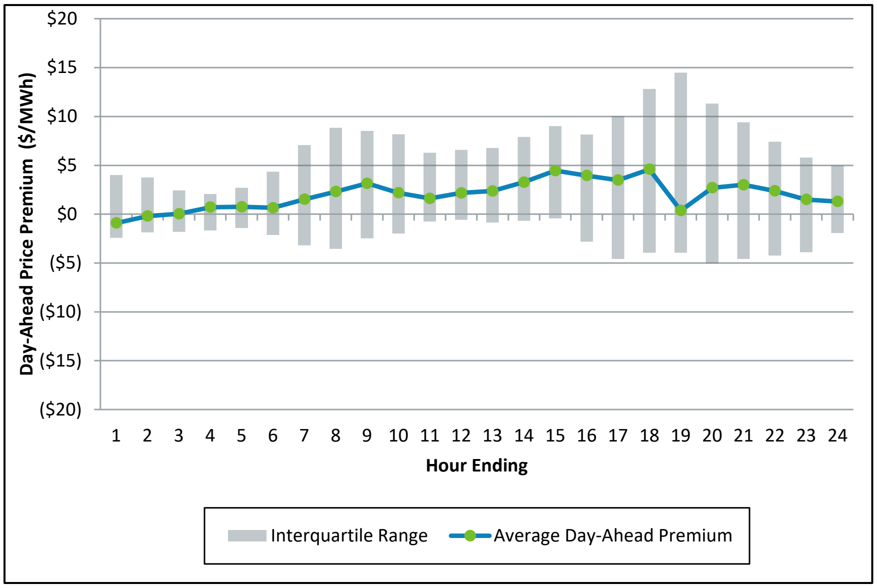
The day-ahead premium at the Hub averaged $1.98/MWh in 2024, the highest premium over the five-year period. While average day-ahead premiums increased, median day-ahead premiums fell in 2024. This disconnect highlights that average price premiums are influenced by hot or cold days where prices are high due to high summer loads or high winter natural gas prices. January 2024 had the second highest day-ahead prices of any month, and the largest day-ahead price premiums. Real-time prices tended to be lower due to higher real-time renewable generation that had not cleared in the day-ahead market. During June 2024, average day-ahead prices were higher despite real-time scarcity pricing on June 18, 2024. In the days following the shortage event, generators frequently self-scheduled in the real-time market. This was likely a measure taken to avoid potential Pay-for-Performance penalties as loads and temperatures remained high in the days following the event.

In percentage terms (as a percentage of the day-ahead LMP), the 2024 price premium (4.8%) was also the highest in the reporting period. Between 2020 and 2024, the average price premium ranged from as low as -$0.06/MWh (in 2020) up to the high seen this year. The variability in day-ahead price premiums remained lower in 2024. However, these percentiles generally track the average day-ahead Hub LMP (orange series, right axis).

Convergence by Time of Day

While average day-ahead price premiums were reasonably consistent through the day, there was more variability in certain hours. Figure 3-5 below shows, by hour, the average day-ahead price premium at the Hub (blue line). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead price premium.

Figure 3-5: Average Hourly Day-Ahead to Real-Time Hub Price Differences, 2024



The average day-ahead price at the Hub exceeded the average real-time price during all but two hours in 2024 (HE 1 and HE 2). The day-ahead price premium ranged from -$0.91/MWh (HE 1) to $4.59/MWh (HE 18). The price premium tended to be higher during on-peak hours (HE 8 through HE 23) with the day-ahead premium averaging $2.72/MWh during this period, up from $1.40/MWh in 2023. We continue to see higher day-ahead price premiums during the middle of the operating day, particularly on days with high solar output. Additionally, higher day-ahead premiums during July led to higher than normal day-ahead premiums during HE 15 through HE 18. During several days in mid-July, tight conditions were expected and very little virtual supply cleared in the day-ahead market during those hours despite high solar forecasts.

3.2 Supply-side Factors

This section explores the key supply factors impacting energy market outcomes. Section 3.2.1 looks at trends in both fuel and emissions costs. Section 3.2.2 examines utilization rates of different generator technologies. Section 3.2.3 summarizes price-setting statistics by resource type. Section 3.2.4 looks into priced versus unpriced offer behavior. Section 3.2.5 examines the extent to which renewable generation is curtailed. And lastly, Section 3.2.6 concludes by presenting a recommendation that would allow market participants to submit separate offer schedules for day-ahead and real-time markets without requiring manual overwrites.

Key Takeaways

Fuel and Emissions Costs: Most fuel costs declined year-over-year, with the exception of natural gas, which remained largely unchanged ($3.04/MMBtu in 2023 vs. $3.06/MMBtu in 2024). Emissions costs under the Regional Greenhouse Gas Initiative (RGGI) increased significantly. Combined, RGGI and the Massachusetts Electricity Generator Emission Limits (MA EGEL) programs contributed an estimated $8/MWh—approximately 18% of the $44/MWh average annual load-weighted energy price.

Generator Utilization Trends: Combined-cycle gas units saw higher utilization in 2024, offsetting reduced net imports. Nuclear generation also increased compared to 2023, when multiple units were on extended outages. By contrast, hydroelectric generation experienced a decline in capacity factor in 2024, attributed to drier conditions.

Price-Setting: Natural gas continued to play a central role in price formation in 2024; gas generators were marginal for 36% of load in the day-ahead market and 81% in the real-time market.

Non-Price-Setting Supply: Approximately two-thirds of total supply in both the day-ahead and real-time markets came from non-price-setting resources, consistent with prior years. The presence of large volumes of non-price-setting supply can lead to low or negative prices, although the frequency of negative prices remained relatively low in 2024.

Curtailment: The curtailment of economic generation from renewable resources was low in 2024, amounting to only 3.4 MW per hour on average. Most of this curtailment occurred because of transmission limitations.

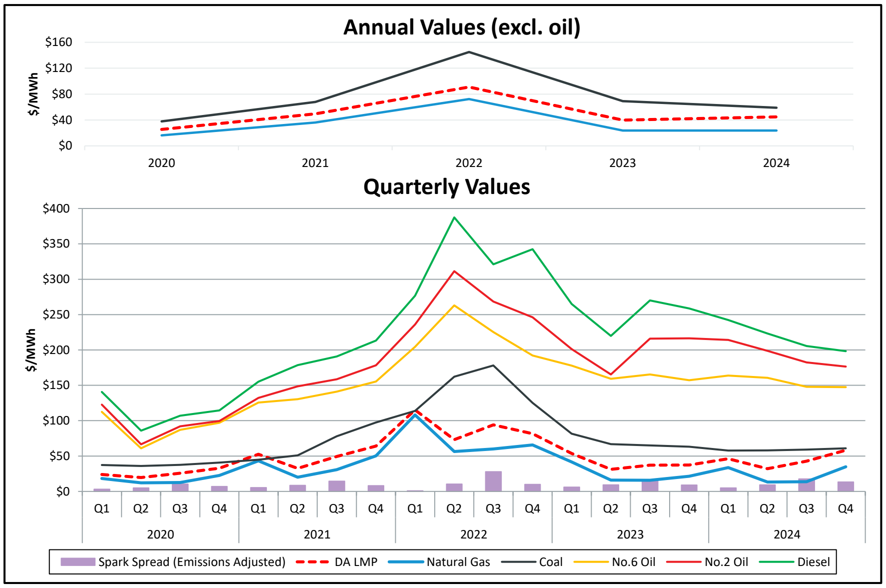
Recommended Enhancement to Bidding System: To better support low-marginal-cost renewable resources, the ISO's systems should allow market participants to submit separate offer schedules for day-ahead and real-time markets without requiring manual overwrites. Currently, when a resource clears in the day-ahead market, the often-higher day-ahead offer prices automatically carry into real-time dispatch, which has resulted in some renewable resources being incorrectly dispatched down.

3.2.1 Generation Costs and Profitability

Day-ahead and real-time electricity prices remain closely correlated with the estimated cost of operating a natural gas-fired generator. In 2024, natural gas-fired generators continued to be the dominant price setters and comprised half of total system supply. The relationship between electricity prices and generation fuel costs is shown in Figure 3-6 below, alongside the estimated spark spread (gross margin) for an average natural gas-fired generator.[145]

[145] Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the day-ahead on-peak LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8, adjusted for the additional estimated emissions costs of a standard gas-fired generator.

Figure 3-6: Estimated Generation Costs and On-Peak LMPs

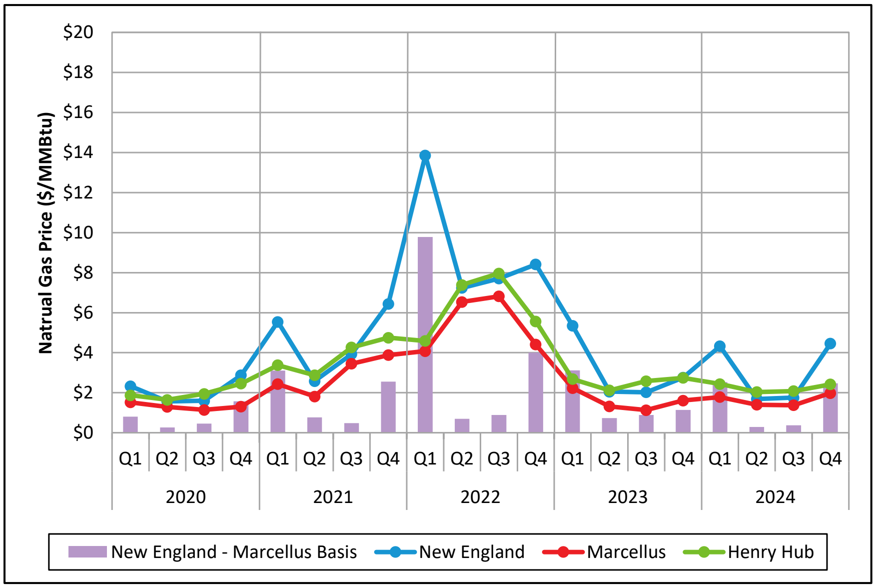


Natural gas generation costs averaged $24/MWh in 2024, similar to 2023. As discussed in Section 1.2, natural gas prices were exceptionally low in New England outside of winter months due to high national natural gas stocks and low prices at Henry Hub and Marcellus. Summer spark spreads averaged $18/MWh in Q3, with spreads as high as $200/MWh occurring in some hours. Such high day-ahead spark spreads occurred during high-load periods when gas generation approached full utilization in the day-ahead market and other sources of generation set price.[146] As discussed below, while gas prices remained relatively low throughout 2024, emissions prices increased significantly as a share of gas generator production costs.

The relationship between New England gas prices and Henry Hub and Marcellus prices is shown in Figure 3-7 below.

[146] For more information, see the IMM's *Summer 2024 Quarterly Markets Report* (December 18, 2024), Section 4.1, available at https://www.iso-ne.com/static-assets/documents/100017/2024-summer-quarterly-markets-report.pdf.

Figure 3-7: New England vs. Henry Hub and Marcellus Natural Gas Prices



New England natural gas prices are primarily determined by natural gas hub prices, particularly Marcellus, and are significantly affected by regional pipeline constraints during cold weather. In the warmer months (in Q2 and Q3), when natural gas demand is lower and pipelines unconstrained, the spreads between New England and Marcellus hub prices averaged less than $1/MMBtu, reflecting broad access to national supplies. By contrast, during colder months (in Q1 and Q4), natural gas heating demand takes up significant amounts of pipeline capacity, leader to more constrained pipelines and higher average spreads of approximately $2.50/MMBtu.

Industry-Standard Profitability Metrics

Industry-standard profitability metrics for gas-fired generators include implied heat rates and spark spreads. Implied heat rates reflect the efficiency of a generator that would break even at given LMPs and gas prices after adjusting for estimated emission prices. Spark spreads reflect the gross profit margin between LMPs and gas prices for generators of a given heat rate. Notable reference heat rates include 7,800 Btu/kWh, the average heat rate for a New England gas generator, and 6,451 Btu/kWh, the standard efficiency of a new entrant combined cycle gas-fired generator.[147] Emissions-adjusted implied heat rates and spark spreads across several reference heat rates for 2020-2024 are shown in Table 3-5.

[147] The IMM uses 7,800 Btu/kWh to represent the average heat rate of New England natural gas generators. The estimated new entrant combined cycle heat rate is provided in the ISO-NE Net Cone and ORTP Analysis performed by Concentric Energy Advisors, Inc. and cited in ISO filings to the Federal Energy Regulatory Commission for FCA 16. The analysis estimates that a new entrant combined-cycle unit would have a heat rate of 6,394 Btu/kWh in shoulder seasons, 6,573 Btu/kWh in summer, and 6,429 Btu/kWh in winter. Weighting these estimates by the number of days in a year yields an average heat rate of 6,451 Btu/kWh.
See ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward (December 2020), p. 35, available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

Table 3-5: Annual Average On-Peak Implied Heat Rates and Spark Spreads (Clean)

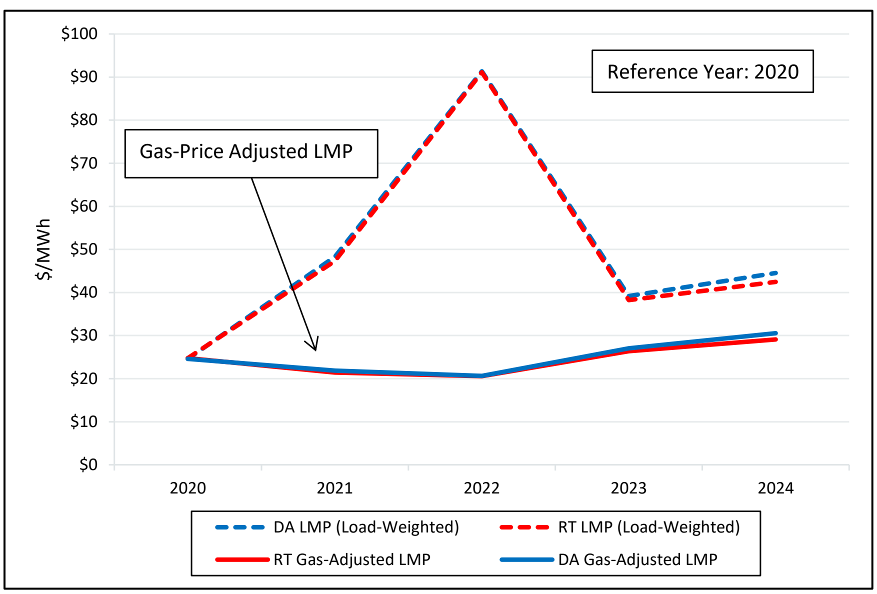
Year	Day-Ahead On-Peak LMP ($/MWh)	Gas Price ($/MMBtu)	Implied Heat Rate with Emission Costs (Btu/kWh)	Spread ($/MWh) corresponding to Heat Rate (Btu/kWh), emissions adjusted					
				6,451	7,000	7,800	8,000	9,000	10,000
2020	26.57	2.09	10,783	10.68	9.32	7.35	6.86	4.39	1.93
2021	51.77	4.62	9,985	18.32	15.48	11.33	10.29	5.11	(0.08)
2022	92.17	9.28	9,150	27.19	21.66	13.60	11.58	1.51	(8.56)
2023	41.02	3.04	10,710	16.31	14.21	11.15	10.38	6.55	2.72
2024	46.62	3.06	10,878	18.97	16.62	13.19	12.34	8.05	3.76

Gas prices were relatively unchanged on average in 2024 relative to 2023, while average on-peak day-ahead LMPs increased 14% to $47/MWh in 2024. Gas generator profitability remained stable in 2024 as LMPs generally reflected static gas prices and increasing emissions costs.

Natural Gas Price-Adjusted LMP

Although there is a significant positive correlation between changes in LMPs and changes in natural gas prices, LMPs are also influenced by other factors such as shifts in the energy supply mix, emissions costs, system demand, and unforeseen events such as unplanned equipment outages. The gas price-adjusted LMP is a high-level metric used to estimate the impact of these non-gas price factors on the energy price and is shown in Figure 3-8 below.[148]

Figure 3-8: Annual Average Natural Gas Price-Adjusted LMPs



Gas-adjusted LMPs rose to $31/MWh in the day-ahead market and $29/MWh in the real-time market in 2024. This marks an increase from the relatively flat gas-adjusted LMPs observed in

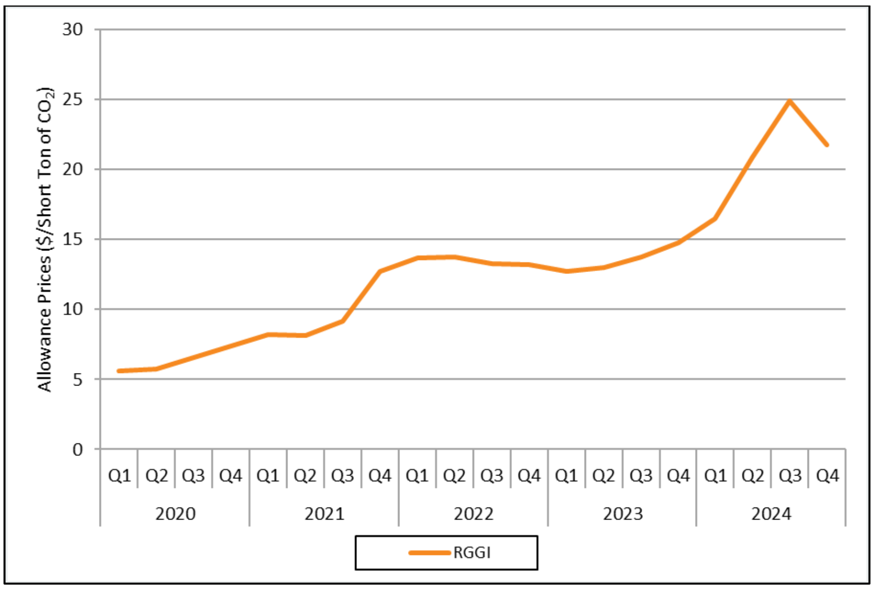
[148] The gas price-adjusted LMP is derived by dividing the reference year natural gas price (2020) by the current year natural gas price, then multiplying by the load-weighted LMP.

2020-2022, which indicate that changes in gas prices explained most of the variation in LMPs during those years. Gas-adjusted LMPs rose in 2023 due to decreases in net imports and extended nuclear outages, resulting in a decrease in fixed supply and increase in relatively costly generation. In 2024, net imports fell further in 2024 (see Section 4), and higher emission costs resulted in higher energy prices despite relatively stable natural gas prices. Day-ahead LMPs were marginally higher than real-time LMPs throughout the year (see Section 3.1.4).

Regional Greenhouse Gas Initiative (RGGI) Prices

The RGGI program is the primary source of emission costs for fossil fuel-fired generators in New England.[149] In 2024, RGGI allowance prices reached record levels, rising by 55% year-over-year from an average of \$13 to \$21 per short ton of CO_2.

Figure 3-9: Regional Greenhouse Gas Initiative Secondary Market Prices



Prices were particularly elevated during the summer months, peaking in August just below \$28/short ton of CO_2 in the secondary market. This notable price increase is due to a combination of the following market dynamics:

- Future emissions limits: The ongoing third RGGI program review has created some market uncertainty, with participants potentially anticipating even stricter emissions limits than those implemented after the 2017 program review.[150]
- Market activity: In 2004, there was an increase in participation of investors without compliance obligations in futures and options contracts.[151]

[149] See RGGI's *Elements of RGGI* page, available at https://www.rggi.org/program-overview-and-design/elements

[150] For more information see RGGI's *Program Review* page, available at https://www.rggi.org/program-overview-and-design/program-review

[151] See Potomac Economics' *Report on the Secondary Market for RGGI CO_2 Allowances: Fourth Quarter 2024* (February 2025), available at https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2024_Q4.pdf

- Supply/demand dynamics: The RGGI program's emissions cap reduction schedule continues to reduce the allowance quantity (approximately 2.3 million tons of CO_2 per year) while electricity demand for allowances is anticipated to grow.[152]
- Allowance cost controls: In March 2024, the Cost Containment Reserve (CCR), a mechanism to help moderate price spikes by releasing additional allowances, was fully depleted before the higher-demand summer period. When prices exceeded the CCR trigger of $15.92/short ton, no additional supply was available to moderate the price increase.[153]

Massachusetts EGEL (MA EGEL) Prices (310 CMR 7.74)

In addition to the RGGI program, Massachusetts generators must also comply with requirements administered by the Massachusetts Department of Environmental Protection (MassDEP).[154] The MA EGEL program places an annual cap on aggregate CO_2 production for the majority of fossil fuel-fired generators within the state.[155] The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050.[156,157]

The annual quantity and volume-weighted clearing prices for CO_2 allowances sold during the MA EGEL auction are shown in Figure 3-10 below.[158, 159]

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[152] The RGGI cap is currently set to decline 30% from its 2020 level by 2030. See *RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030* (August 23, 2017), available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf

[153] The CCR will be replenished in March of 2025. See Potomac Economics' *Market Monitor Report for Auction 63* (March 13, 2024) p. 3, available at https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/63/Auction_63_Market_Monitor_Report.pdf

[154] See the Massachusetts Department of Environmental Protection's page *Electricity Generator Emissions Limits (310 CMR 7.74),* available at https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

[155] Participating generators are fossil fuel-fired generators with a nameplate capacity of 25 MW or more. See Massachusetts Department of Environmental Protection's *310 CMR 7.00: Air Pollution Control* report, available at https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download

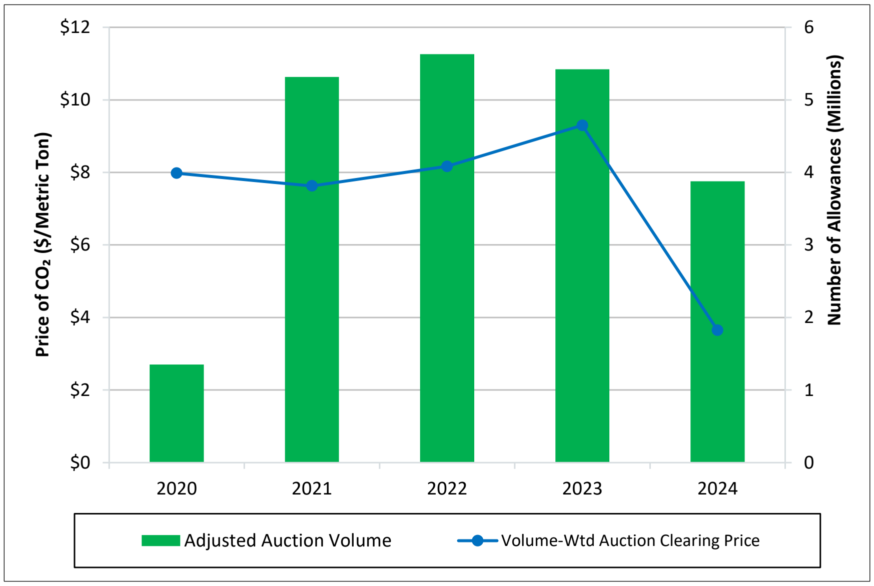
[156] The annual emissions cap for 310 CMR 7.74 will reduce by 223,876 metric tons in each subsequent year, eventually reaching 1,791,019 metric tons in 2050.

[157] The regulation requires fossil fuel-fired generators to hold an allowance for each metric ton of CO_2 they produce during a year. For the first two years, these allowances were primarily allocated based on historical emissions levels, but beginning in 2021, allowances were available for sale through auction only. The program also allows generators to trade emissions allowances to meet their compliance obligations. For more information on allowance allocations see Potomac Economics' *Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter 2024* (November 2024), available at https://www.mass.gov/doc/market-monitor-quarterly-report-2024-q3/download

[158] For the 2020 compliance year, MassDEP directly allocated 50% of the emissions cap. Beginning in 2021, MassDEP no longer distributed allowances through direct allocation and all allowances were offered at auction.

[159] There were fewer allowances at auction in 2021 compared to 2022 because there were more allowances banked going into that year. Emission caps are adjusted based on banked allowances. For example, to calculate the 2022 cap, you subtract the 2.7 million banked allowances minus 223,875 (because the number of banked allowances is over 223,875) from the original cap of 8 million to get 5.6 million metric tons of CO_2 emissions.

Figure 3-10: Massachusetts EGEL Auction Results



The 2024 volume-weighted auction price for allowances fell 60% to $3.65/metric ton of CO_2 despite the tightening of the emissions cap. Clearing prices in the quarterly auctions ranged from $1.25-$5.65/metric ton reflecting electricity generators' compliance needs and market expectations. In addition, 2024 emissions were below the program's cap trajectory through 2031 which suggests limited near-term scarcity pressure. While generators continue to factor allowance costs into their energy market offers,[160] the thin secondary market could expose participants needing additional allowances to significant price premiums in the future.[161]

3.2.2 Capacity Factors

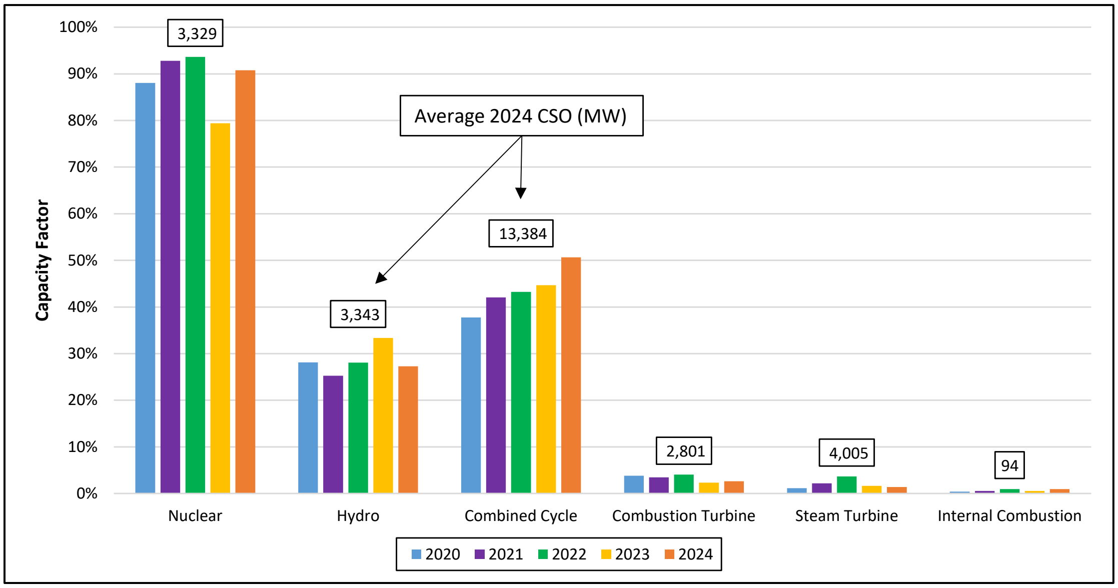
Capacity factors provide a high-level view of the relative economics and physical capabilities of generators.[162] Average capacity factors by generator type are shown in Figure 3-11 below.

[160] To incorporate the cost of these allowances into generator reference levels, the IMM uses an adder that values the allowances based on recent trades and auction results.

[161] See Potomac Economics' *Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter 2024* (November 2024), available at https://www.mass.gov/doc/market-monitor-quarterly-report-2024-q3/download

[162] For the purposes of this section, capacity factor is measured as the ratio of a generator's average hourly output relative to their total capacity supply obligation (CSO).

Figure 3-11: Capacity Factor by Generator Type



Nuclear capacity factors recovered to 91% in 2024 following the completion of extended nuclear outages in 2023. Hydro capacity factors fell to 27% from 33% in 2023 following drier conditions and more favorable water conditions in 2023. Combined-cycle (CC) capacity factors increased significantly in 2024, averaging around 50%. The increase in capacity factors for these generators is attributable to the low cost of gas outside of winter months and the decrease in net imports leading to the use of more relatively efficient native generation. By contrast, the average capacity factor of combustion turbines and steam turbines remained unchanged from 2023 as relatively inefficient units were used far less frequently than combined-cycle units. The increase in CC utilization and static non-CC utilization are consistent with changes in estimated generator profitability as discussed in Section 0. The utilization of steam turbine generators remained less than 1% as such relatively costly and inflexible generation was generally only used in winter months.

3.2.3 Marginal Resources

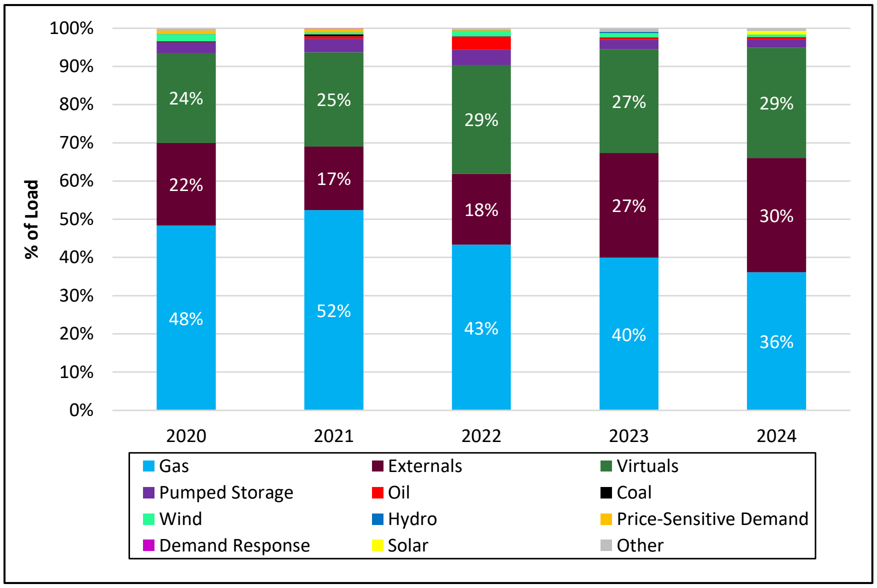
The price of energy is largely determined by the marginal resource (i.e., the resource that would provide the next increment of energy). Consequently, trends in marginal resources can provide important insights into changes in energy prices over time. Below, we present statistics on marginal resources by transaction and fuel type in both the day-ahead and real-time energy markets.[163]

[163] The statistics presented in this section are calculated on a load-weighted basis. When more than one resource is marginal, the system is typically transmission-constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Day-Ahead Energy Market

The percentage of load for which each transaction type was marginal in the day-ahead energy market over the last five years is illustrated in Figure 3-12 below.[164,165]

Figure 3-12: Day-Ahead Marginal Resource by Transaction Type



Gas-fired generation was the most frequent marginal resource type in 2024, setting price for 36% of total day-ahead load. However, this marked the smallest percentage of load for which gas was marginal over the last five years. Meanwhile, external transactions were marginal more frequently in 2024 (30%) than any other year in the reporting period. Notably, external transactions over the Canadian interfaces were marginal for higher percentages of load, collectively increasing from 13% in 2023 to 16% in 2024.[166] Virtual transactions (supply 16%, demand 13%) continued to set price frequently and at a comparable rate across the five years. No other resource type was marginal for more than 3% of load in the day-ahead market in 2024.

Real-Time Energy Market

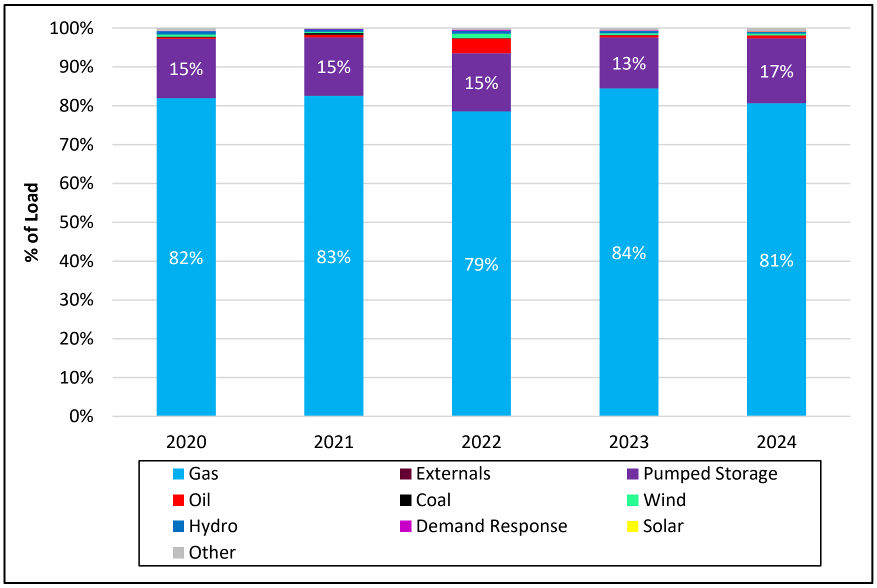
The percentage of load for which each transaction type was marginal in the real-time energy market over the last five years is illustrated in Figure 3-13 below.

[164] The “other” category contains energy storage, wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, and refuse.

[165] It is important to note that while this section falls within the supply-side section, both demand and supply can set price in the energy market. The types of demand that can set price in the day-ahead market include price-sensitive demand, asset-related demand (ARDs), battery storage demand, and virtual demand, and export transactions.

[166] The percentage of cleared external transactions from Canada that were priced grew between 2023 and 2024. The composition of these transactions is looked at in greater detail in Section 4.1.2.

Figure 3-13: Real-Time Marginal Resource by Transaction Type



As with prior years, natural gas-fired generators set price for the highest percentage of load in the real-time market in 2024 (81%).[167] Pumped-storage generation (12%) and demand (5%) was the second largest price-setter (17%). This represents a modest increase on last year due to extended outages for several of these units in 2023. While wind generators are frequently marginal in real-time, they typically set price in constrained areas with relatively low load. In 2024, wind was the marginal fuel type for less than 1% of total real-time load.

3.2.4 Supply-Side Participation

Some resources are willing to clear in the energy market at any price (price-taking), while others offer supply at a specific price that is used in the market clearing engine to determine commitment and dispatch. The volumes of price-setting vs. non-setting price supply on the system have important implications for price formation. For example, if most supply cannot set price, there is a higher likelihood of low or negative LMPs.

In 2024, non-price-setting-supply made up 67% of total supply in the day-ahead energy market and 65% in the real-time energy market. Non-price-setting supply consists of offers from suppliers that are willing to sell at any price, as well as offers that cannot set price. Market supply may be insensitive to price for several reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 33-35% of supply is considered priced-setting supply (i.e., it is willing to sell at a specified offer price or higher and has the ability to set price).

There are three categories of *non-price-setting* supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

[167] Unlike the day-ahead market, where offers and bids that are *physical* or *financial* in nature can be marginal, in the real-time market only *physical* assets can set price. This means that the real-time price is typically set by generators, pumped-storage demand, and demand response resources.

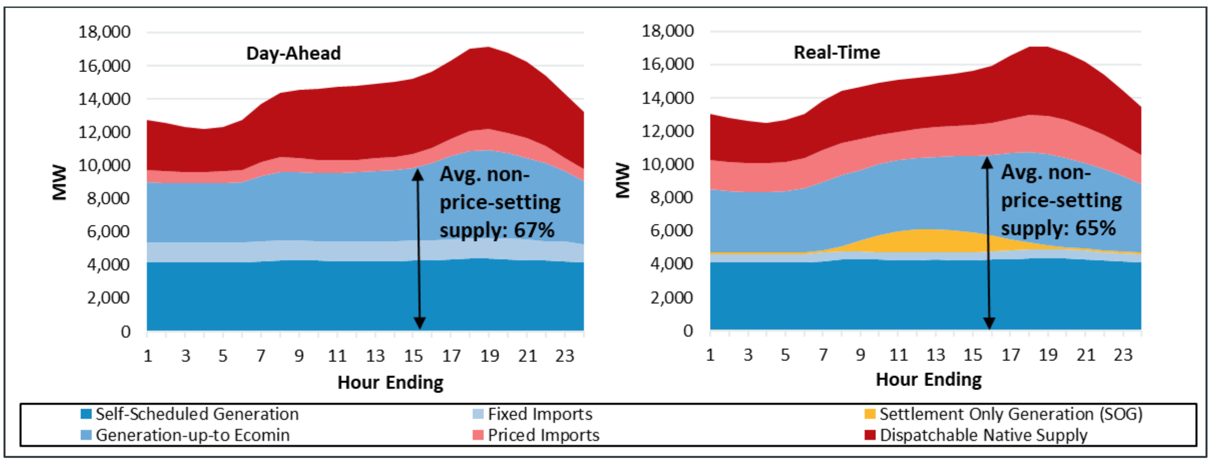
- **Fixed imports** are scheduled to flow power into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).[168]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is below EcoMin.[169]

There are two categories of *price-setting* supply that participate in price formation: dispatchable native supply and priced imports.

- **Dispatchable native supply** is energy from generators, demand response resources (DRRs), and virtual transactions (day-ahead market only) that is dispatched economically (based on its offer price). For generators and DRRs, this is energy delivered at levels within the resource's dispatchable range, above EcoMin.
- **Priced imports** include price-sensitive imports and up-to-congestion transactions.[170, 171]

An hourly average breakdown of price-setting and non-price-setting supply by category for the day-ahead and real-time markets in 2024 is provided in Figure 3-14 below.

Figure 3-14: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2024



On average, non-price-setting supply made up 67% of total supply in the day-ahead market and 65% of total supply in the real-time market. These shares were slightly lower than in the previous few years due to fewer fixed imports in both markets. Price-setting supply averaged

[168] The Economic Minimum (EcoMin) is the minimum MW output available from a generator for economic dispatch.
[169] For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is the portion below 100 MW. Generation-up-to EcoMin does not participate in price formation, as the market software cannot dispatch it up or down.
[170] Up-to-congestion (UTC) transactions are external contracts in the day-ahead energy market that do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are considered willing to pay congestion charges.
[171] There are some nuances to the priced imports category in terms of price-setting ability. While priced imports regularly set price in the day-ahead market, they rarely set price in real-time market. This is because the tie lines are scheduled in advance of the delivery interval in real time and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie lines far away from the scheduled amount determined by the transaction scheduling process.

35% of total supply over all hours in real time in 2024, with its share peaking in hours ending (HE) 18-22 at 37-38%.

In both markets, the daily ramp-ups in load are typically met by additional supply from *generation-up-to EcoMin* (as additional generators are committed) and *price-setting* supply. In the day-ahead market, the share of supply from *self-scheduled* generation (the largest component of unpriced supply) and *fixed imports* was reasonably stable over the course of a day. By contrast, in the real-time market, average hourly self-scheduled generation was higher during midday due to output from settlement-only solar generators (SOGs).[172] In 2024, hourly SOG output averaged 514 MW, or 11% of total real-time self-scheduled generation. These smaller generators do not clear in the day-ahead market because they are not modeled in the market nor centrally dispatched by the ISO control room.[173]

Unpriced Supply and Price Formation Implications

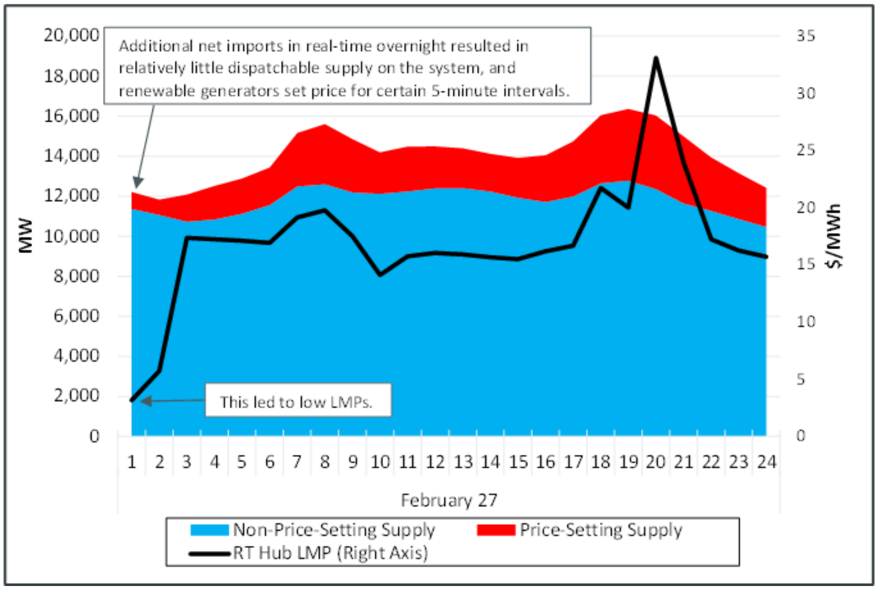
Large volumes of non-price-setting supply can increase the likelihood of low or negative prices. This will become more common when combined with significant amounts of additional capacity from renewable generation (e.g., wind and solar) with low marginal costs. However, we generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand.

The combination of lower loads and large amounts of non-price-setting generation can bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.3% of five-minute real-time pricing intervals in 2024. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the zonal price was negative in only 0.4% of five-minute real-time pricing intervals in 2024. The frequency of negative LMPs is discussed further in Section 3.1.2.

The example shown in Figure 3-15 below illustrates low pricing at a time when a significant amount of non-price-setting supply combined with negative energy supply offers to result in low LMPs.[174]

[172] See Section 1.5 for a discussion on solar generation and changing demand.
[173] SOGs are passive participants in the real-time energy market only.
[174] Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

Figure 3-15: Priced and Unpriced Supply vs. Real-Time LMP, February 27, 2024



In the overnight hours of February 27, loads were relatively low and there was additional fixed-price generation from net imports in real time compared to the day-ahead schedule. As a result, real-time generation needs were less than the amount that cleared in the day-ahead market, and the ISO only had to dispatch a small amount of price-setting generation. The small amount of economically dispatched generation offered into the market at low values, resulting in low prices. The five-minute Hub LMP ranged from -$18.85 to $0.02/MWh from 12:15am to 12:40am, and the hourly price averaged $3.17/MWh during HE 01.

3.2.5 Renewable Generation Curtailment

At times, renewable resources must be dispatched below their available maximum output (i.e., curtailed) despite having zero or negative marginal costs and sufficient fuel to produce at levels exceeding their dispatch. Curtailments result in the loss of low-cost energy, which can increase total system production costs and ultimately raise consumer costs. These outcomes also raise important policy questions about the cost-effectiveness of transmission investments and the value of expanding storage capacity to better integrate renewable generation.

Figure 3-16, below, shows renewable curtailment between 2020 and 2024, segmented by the reason for curtailment. Only resources qualified for do-not-exceed dispatch are included in the following analysis.[175] The reasons shown in the chart are:

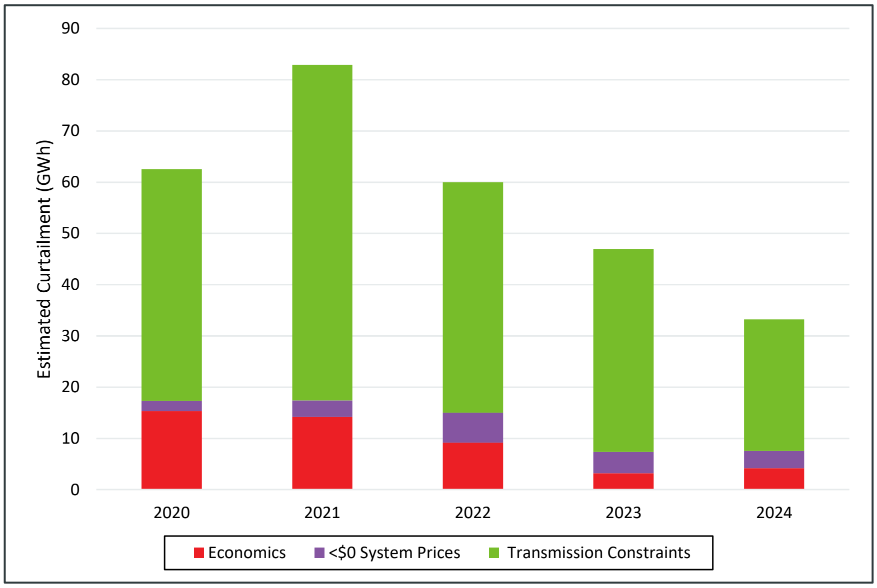
- **Transmission Constraints**: includes times when the system price is >$0/MWh, indicating that $0/MWh marginal cost renewable energy would be utilized by the system if it was available. However, in these cases transmission limitations are resulting in a nodal price <= $0/MWh and a dispatch below the unit's full capability.
- **<$0/MWh System Prices**: includes times when the system price is <= $0/MWh, indicating that system load is being delivered using only fixed generation (i.e.,

[175] Do-not-exceed dispatch allows renewable resources to be dispatched below their maximum potential output by the market-clearing software. Wind and hydro resources have been able to participate since 2016, while solar units were required to begin participating in December of 2023. See the ISO's *Do Not Exceed Dispatch (DNE) Project* page, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/do-not-exceed-dispatch

generation up-to EcoMin) and low-cost, typically renewable, energy. In these cases, only the lowest-cost renewable energy is produced and some $0/MWh (or even-lower-priced) energy will be curtailed.

- **Economics**: includes times when the nodal price is >$0/MWh but energy is offered at positive prices and is not dispatched due to economics.[176]

Figure 3-16: Renewable Curtailment by Reason



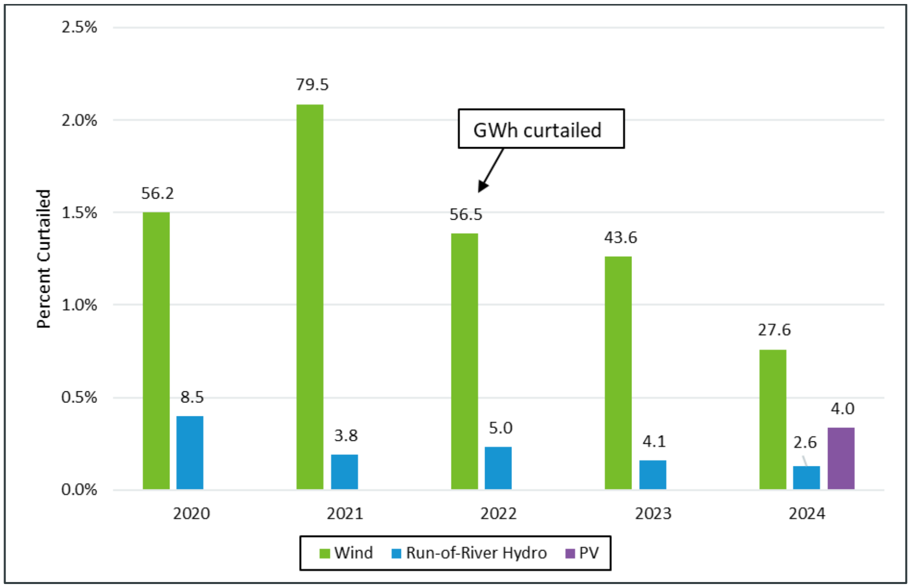
Curtailment of renewable generation has been very low; 34 GWh is the equivalent of 3.9 MW per hour or just 0.3% of total energy supply. Transmission constraints have driven about 77% of the curtailed renewables between 2020-2024. 93% of curtailed renewable capacity in New England between 2020 and 2024 was in Maine and Vermont. Because renewable resources do not have 100% capacity factors, they may be incentivized to build units that exceed the transfer capability of their locally-constrained area to maximize the average output of the generator when fuel is not 100% available. The remaining 17% of curtailed generation was due to offer prices exceeding the nodal LMP when the nodal LMP was greater than $0/MWh.

Figure 3-17, below, shows the percentage of potential renewable output that was curtailed in each year, by fuel type.[177] Labels show the GWhs that were curtailed.

[176] Related to this observation, in the 2022 AMR, we recommended the ISO expand mitigation to export-constrained areas, which would help reduce market-power concerns introduced by renewable generation offering above marginal cost with limited competition in these areas. We continue to recommend the ISO expand mitigation to export-constrained areas, first proposed in the 2022 Annual Markets Report. See the IMM's *2022 Annual Markets Report* (June 5, 2025), available at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

[177] Photovoltaic output in 2023 is omitted due to the December 2023 implementation date of PV DNE rules. 0.8 GWh of PV, or 3% of available PV participating in DNE, was curtailed in December 2023.

Figure 3-17: Renewable Curtailment by Fuel Type



Wind drives about 80% of curtailed renewable energy, but as a percentage of total wind capability it is low, only about 0.8% on average in 2024.

The cost of transmission upgrades necessary to eliminate the very-small volume of curtailed renewable energy are likely more costly than the potential benefits to the system. However, in the future, batteries may be able to reduce curtailment and allow renewables to produce at higher levels when fuel is abundant and deliver the energy when supply and demand conditions are more favorable.[178]

3.2.6 Recommendation to Allow Option For Real-Time-Specific Offer Schedules to Automatically be Used in Real-Time Energy Dispatch, in Support of Renewable Resources

Certain resource types, such as wind and solar generators, have both (1) a tariff-based obligation to offer their energy supply into the day-ahead market, and (2) uncertainty regarding the amount of energy they will produce during real time, due to the variable nature of wind and solar insolation. Such resources may reasonably submit different energy offer prices in the day-ahead and real-time energy markets; higher offer prices in the day-ahead market may be used to reflect the volumetric risk of accepting a day-ahead energy award when real-time output is uncertain, while lower offers in real-time may reflect the low marginal cost of these resources.

The ISO's internal software is currently designed such that if a resource clears for any hour in the day-ahead energy market, then the day-ahead energy schedule (often composed of higher offer prices reflective of volumetric risk) will automatically be used in the real-time market.

[178] The Economic Planning for the Clean Energy Transition (EPCET) study discusses the necessary renewable generation, battery capacity, and transmission build required to reduce, or eliminate, carbon in New England. See the ISO's *Economic Planning for the Clean Energy Transition* report (October 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf

The onus is then on the market participant to develop a process to replace this day-ahead offer schedule with a different set of real-time offers (reflective of marginal cost) during the time period after the day-ahead market closes and prior to the operating day. If the market participant fails to overwrite these offers, their low-cost wind and solar resources may appear out-of-rate to the real-time dispatch software, potentially resulting in these resources being dispatched down and the system being deprived of low-cost energy that errantly appears uneconomic.

We have observed numerous instances during 2024 in which a renewable resource has been dispatched based on real-time offers that exceed estimates of marginal cost (generally $0/MWh). Investigation of these incidents has typically revealed that participant-established procedures for replacing submitted day-ahead offers did not work as intended, and the day-ahead offer prices were inadvertently allowed to flow into real time.

We recommend that the ISO revise its practice of using day-ahead energy offers as the default offer schedule in real-time operations for resources that clear energy awards in the day-ahead market. Resources that reasonably have different day-ahead and real-time energy offer prices should be able to clear in the day-ahead market based on the former set of offers and then be dispatched in real-time based on the latter set of offers, without the need for internal processes to overwrite the former with the latter. It may be particularly useful to address this issue in advance of the growth in low-cost renewable resource penetration that is expected in future years.

3.3 Demand-side Factors

This section explores key factors influencing demand levels and behavior in the energy markets. Section 3.3.1 analyzes the impact of weather and behind-the-meter solar generation on load. Section 3.3.2 takes a deeper look at the nature of demand-side participation.

Key Takeaways

Demand Trends: Average and peak load levels (13,294 MW and 24,871 MW, respectively) increased slightly from 2023 levels, consistent with similar temperatures across both years. Load also rose modestly on a weather-normalized basis. Notably, behind-the-meter (BTM) solar generation continued to lower wholesale load levels and impact the time-of-day profile of load and energy prices across all seasons.

Demand Bidding: Load Serving Entities (LSEs) continued to clear more demand in the day-ahead market relative to real-time load. Additionally, demand bidding remained mostly insensitive to prices with fixed-priced bids continuing to make up the largest share of day-ahead cleared demand. Virtual demand, exports and asset-related demand continued to provide important price-elasticity to the demand side.

3.3.1 Load and Weather Conditions

Net Energy for Load (NEL) averaged just above 13,000 MW per hour in 2024, slightly higher than in 2023, reflecting relatively stable average load levels in recent years. New England's load is shown in Table 3-6 below.[179, 180]

Table 3-6: Average, Peak and Weather-Normalized Load

Demand (MW)	2020	2021	2022	2023	2024	% Change '23 to '24	Sparkline
Load (avg. hourly)	13,305	13,561	13,576	13,096	13,294	2%	
Weather-normalized load (avg. hourly)	13,242	13,419	13,514	13,132	13,226	1%	
Peak load (MW)	25,121	25,801	24,780	24,043	24,871	3%	
Minimum load (MW)	8,392	8,646	8,694	8,617	8,775	2%	

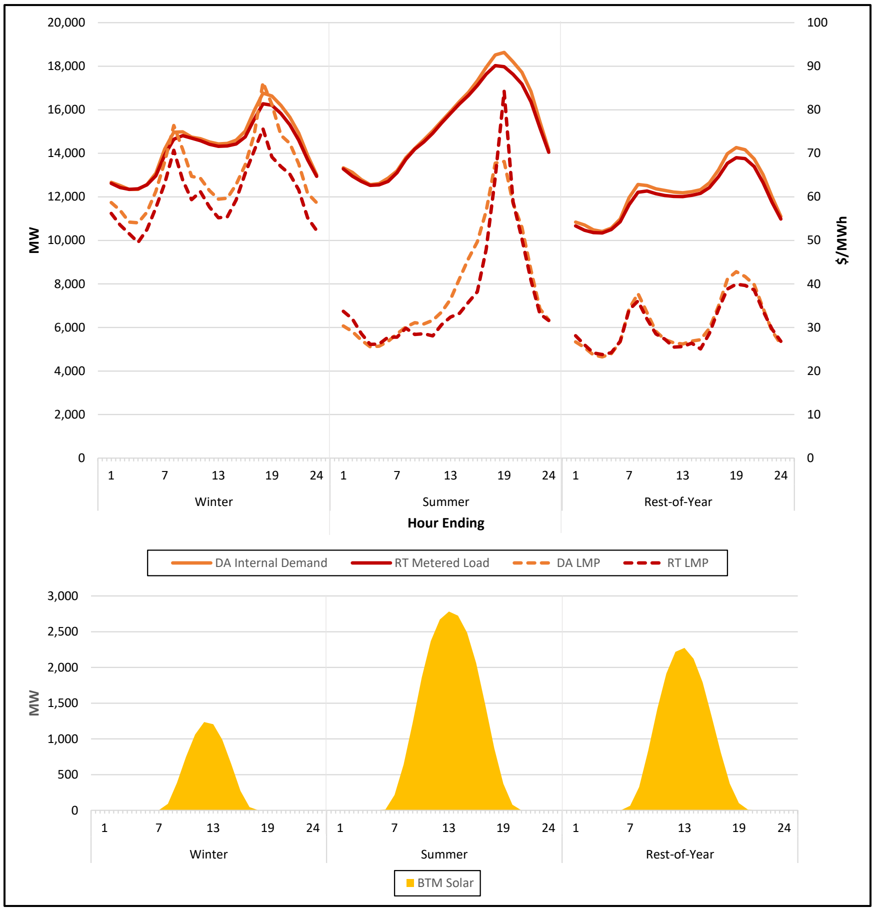
Weather normalized load was similar to actual load in 2024, indicating average weather conditions throughout the year. Peak load reached 24,871 MW on July 16, marking the third consecutive year that peak load was below 25,000 MW. Minimum load (8,775 MW) occurred during the afternoon of April 27 during mild weather conditions when BTM solar load reductions totaled 3,500 MW.

Demand Profiles and Energy Prices

The connection between energy prices and load is particularly evident over the course of the operating day. Figure 3-18 below shows the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs, along with average hourly load reductions from behind-the-meter (BTM) solar generation. The figure is broken out into winter, summer, and rest-of-year averages to illustrate seasonal differences in load curves, prices, and solar generation.[181]

[179] In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped-storage demand.
[180] Weather-normalized load estimates what load would be if monthly total heating degree days and cooling degree days were in line with historical averages. The estimate also factors in differences due to non-holiday weekdays and leap days.
[181] Winter seasons include December, January, and February; summer seasons include June, July, and August.

Figure 3-18: Average Demand and LMP by Hour, 2024[182]



BTM solar generation continued to influence the load profile even in winter months in 2024, with over 1,000 MW of BTM generation at noon and corresponding dips in midday load.[183] Summer months had both the highest load and ramps, with average peak load at nearly 18,000 MW. While summer BTM solar typically peaked well over 2,500 MW, loads do not typically fall midday in summer as air conditioning demand sharply increases. For "Rest-of-Year" loads typically fall midday with over 2,000 MW of BTM generation.

Across all seasons, day-ahead and real-time prices follow load profiles, with lower LMPs during peak solar hours in winter and rest-of-year and sharply increasing evening LMPs in summer. Figure 3-18 also shows that day-ahead LMPs typically exceeded real-time LMPs as discussed in Section 3.1.4, and cleared demand typically exceeded real-time load as discussed further in Section 3.3.2.

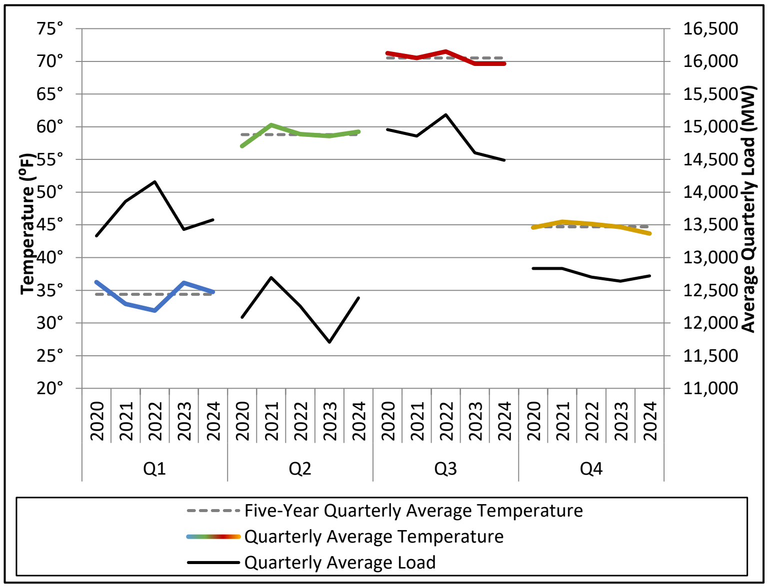
Impact of Weather

182 Day-ahead internal demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped-storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

183 The ISO does not meter output from BTM solar installations or directly measure BTM capacity. For details on behind-the-meter estimation methods, see ISO-NE System Planning's *Load Forecast* page, available at https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/.

Weather is a significant driver of load in New England. Loads are driven by air conditioning demand in hot weather and electric heating demand in cold weather. Quarterly average and five-year average temperatures for 2020 through 2024 are illustrated in Figure 3-19 below.[184]

Figure 3-19: Seasonal vs. Five-Year Average Temperatures



Weather conditions in 2024 were similar to those in 2023, resulting in comparable load levels. Winter weather (Q1) was relatively mild, with average temperatures above freezing (35°F). As heating electrification continues to grow, winter demand levels—and their sensitivity to temperature—are expected to increase. Summer weather (Q3) was also mild and consistent with 2023, with average hourly loads of approximately 14,500 MW.

3.3.2 Demand Bidding

The quantity and pricing of bid-in demand in the day-ahead market have important implications for both price formation and system operations. Generator commitments for the operating day are determined through the day-ahead market clearing process, which matches supply and demand at least cost and serves as a key input into the ISO's Reserve Adequacy Analysis (RAA).[185]

When real-time demand exceeds day-ahead cleared demand, higher-cost resources may need to be dispatched to meet the energy gap resulting in higher real-time energy prices relative to day-ahead prices. Additionally, demand bids can directly influence price formation. In 2024,

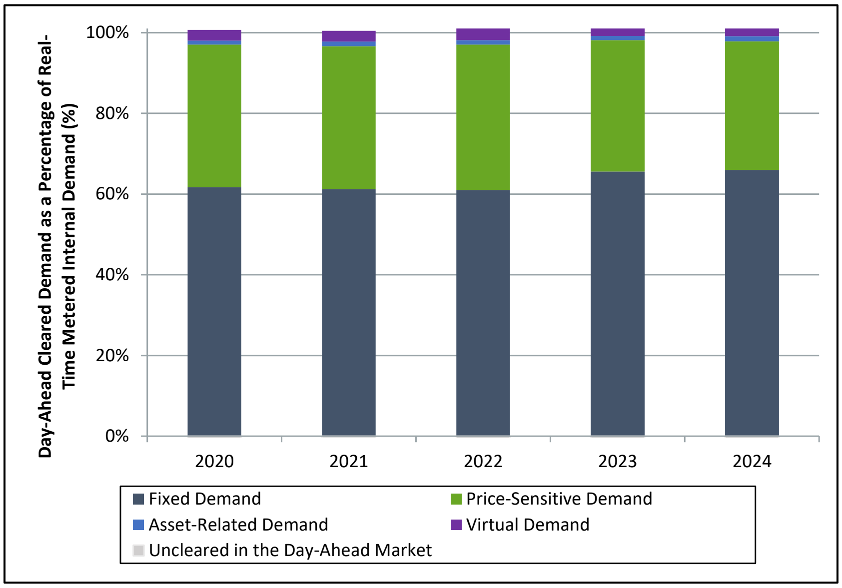
[184] As of July 27, 2023, the ISO calculates New England average temperatures based on new methodology and data collection that incorporates observations from 23 cities. See ISO Newswire's *ISO-NE weather forecast improvements aid grid operations* article (July 27, 2023), available at https://isonewswire.com/2023/07/27/iso-ne-weather-forecast-improvements-aid-grid-operations/

[185] The reserve adequacy analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available at least cost to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. For more information, see Section 3.4.

demand set the clearing price for 19% of day-ahead load, while asset-related demand—such as energy storage charging or pumping—set price for 5% of real-time load.[186]

Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 3-20.[187]

Figure 3-20: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type

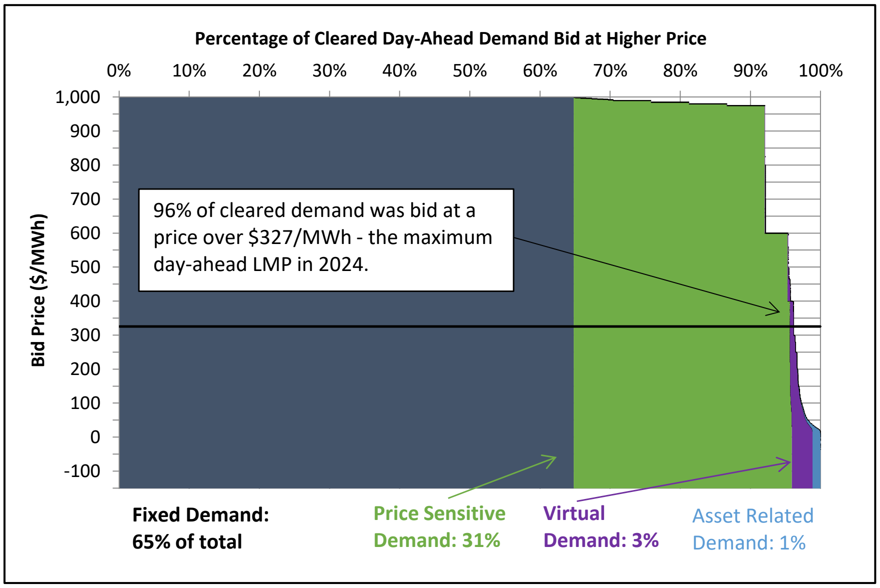


Participants cleared 102% of real-time load in the day-ahead market in 2024 continuing a trend of slightly over-clearing relative to real-time load over the past five years. Day-ahead fixed demand, cleared priced bids, and asset-related demand accounted for 99% of real-time load, unchanged from previous years. This indicates that demand over-clearing is primarily driven by virtual demand.[188]

Aggregating cleared demand components by price provides additional insight into bidding behavior and the price sensitivity of demand. Figure 3-21 aggregates annual cleared demand by bid price.

[186] See Section 3.2.3 for a discussion of marginal resources and price-setting load.
[187] Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.
[188] For more information on virtual demand, see Section 5.

Figure 3-21: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Internal demand in New England continued to be primarily price insensitive. Nearly two-thirds of total day-ahead cleared demand was bid as fixed demand. Price-sensitive demand bids accounted for 31% of all day-ahead cleared demand but frequently cleared with bid prices well above expected LMPs. This bidding behavior indicates that load-serving entities were generally only willing to reduce load in extreme pricing scenarios.

Virtual demand and price-sensitive storage demand bids often have lower bid prices and account for approximately 4% of cleared demand bids. In total, the aggregate day-ahead internal demand curve is relatively price-insensitive around expected LMPs and has remained relatively unchanged year-over-year.

3.4 System Reliability

The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[189] To meet reliability standard requirements, the ISO may commit additional resources required to meet the real-time operating plan, to supplement capacity availability in constrained areas, to provide voltage protection, and to support local distribution networks. The ISO also might manually constrain (posture) resources to maintain adequate operating reserves. This typically occurs through limiting output from fast-start, pumped-storage generators during prolonged, tight market conditions.

[189] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. See NERC's *Standards* page, available at http://www.nerc.com/pa/stand/Pages/default.aspx. See NPCC's *Standards* page, available at https://www.npcc.org/program-areas/standards-and-criteria. See *ISO Operating Procedures* available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

Key Takeaways

In 2024, the day-ahead market generally secured enough physical supply to meet the anticipated real-time load, resulting in minimal reliance by the reserve adequacy analysis (RAA) on suppliers to exceed their day-ahead energy awards.

There has also been a significant decrease in reliability commitments and posturing over the past five years. In 2024, the few reliability commitments made were mostly in-rate, limiting reliability uplift payments.

Load forecast error and volatility in 2024 were similar to 2023. Challenges in forecasting behind-the-meter (BTM) solar were the most frequent driver of forecast error. While forecast error has implications for price convergence, overall forecast error levels were similar to prior years.

3.4.1 Reserve Adequacy Analysis and the Day-Ahead Energy Gap

The commitment, dispatch and pricing outcomes in the financial day-ahead market may not always reflect expected physical real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than will be needed in real time. When this happens, ISO-NE must ensure there is sufficient energy and reserve capability to meet forecasted real-time load and reserve requirements.

To that end, after the day-ahead market, the ISO performs the Reserve Adequacy Analysis (RAA) to evaluate day-ahead cleared supply against forecasted energy and reserve requirements. If the day-ahead market did not clear enough *physical* supply to meet the ISO's forecasted demand and reserve requirements, the RAA may rely upon resources to operate at levels above their day-ahead schedules and, infrequently, may require additional generator commitments.[190] In 2025, the ISO implemented the Day-Ahead Ancillary Services market, which will ensure sufficient physical supply to meet these reliability needs through a market construct.

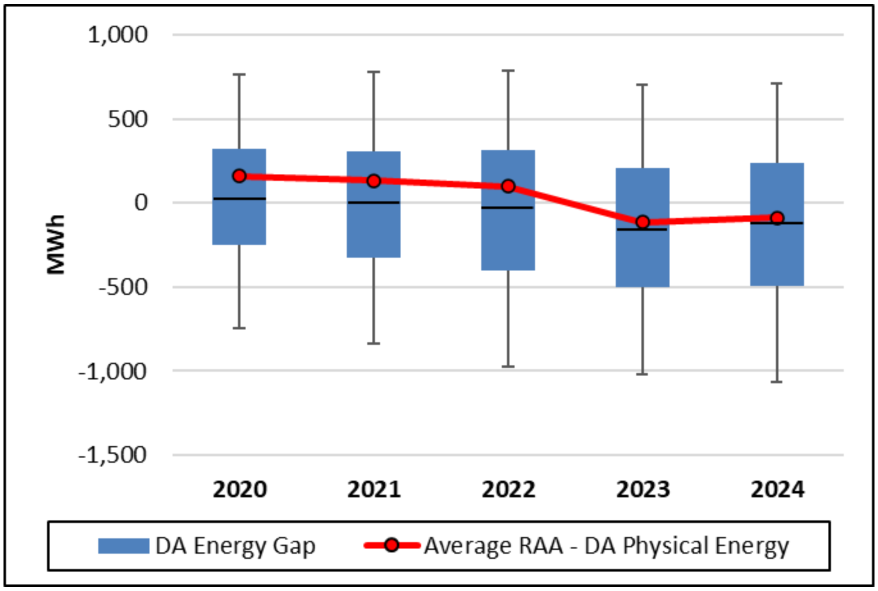
We define the day-ahead energy gap as the difference between the amount of physical cleared generation (i.e., excluding virtual supply) in the day-ahead market and the expected real-time load. Statistics on the value of the energy gap for the last five years are shown in Figure 3-22.[191,]

[190] One such commitment occurred in 2023. A ~340 MW resource was committed by the RAA process for a five-hour period on October 22, 2023.

[191] This box plot shows the 25th and 75th percentiles (interquartile range), the median (50th percentile), along with the more extreme observations at the 5th and 95th percentiles.

[192] The figure also includes the average energy quantity from physical suppliers relied upon by the RAA in excess of those suppliers' day-ahead energy awards.[193]

Figure 3-22: Day-Ahead Energy Gap and RAA Reliance on Supply above Day-Ahead Award



When the energy gap is greater than zero, the RAA process relies upon generation to operate above day-ahead energy awards to meet expected real-time load. While the magnitude of the day-ahead energy gap can vary, the median value is close to zero and this value has decreased over time. As a result, the reliance of the RAA process on resources to operate at levels above their day-ahead energy awards has also decreased. The negative value shown in 2024 (red line) indicates that in 2024 the day-ahead market typically procured sufficient physical supply to meet expected real-time load, and the RAA was therefore less frequently reliant on suppliers to operate above their day-ahead energy awards. This outcome aligns with observations on day-ahead demand participation; on average in 2024, market participants cleared more demand in the day-ahead market than what they consumed in real time.[194]

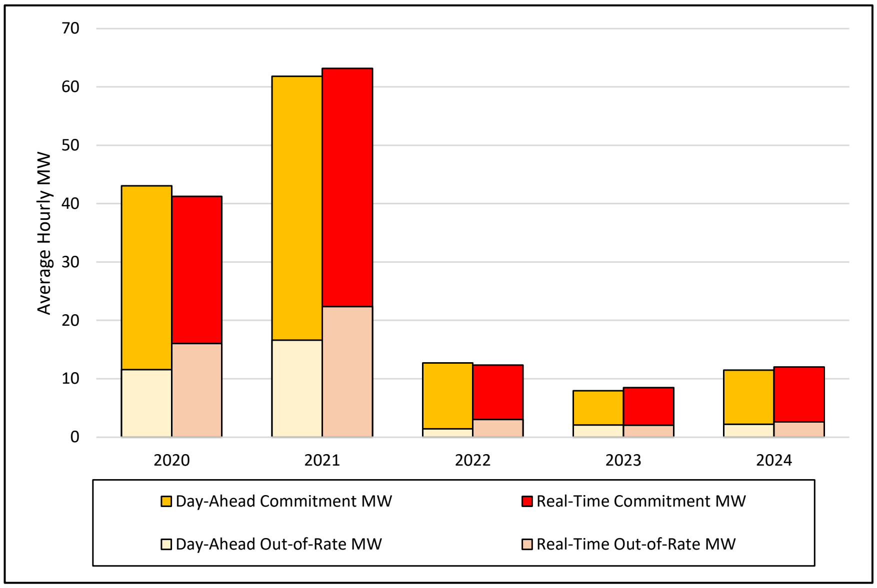
3.4.2 Reliability Commitments and Posturing

Reliability commitments include manual generator commitments for local second contingency protection, voltage support, or other special constraints. System operators direct such commitments for reliability purposes rather than generator economics. Consequently, reliability commitments are often out of merit and may negatively impact price formation for other online generators. Average hourly energy output (MW) from reliability commitments for

[192] The Day-Ahead Ancillary Services Initiative (see Section 9) incorporates the load forecast into the day-ahead market's commitment, clearing, and pricing processes, thereby resolving any non-negative day-ahead energy gaps through a market mechanism rather than the out-of-market RAA process.
[193] For instance, suppose 12,000 MW of physical supply clears energy awards in the day-ahead market, and the RAA needs to satisfy a load forecast of 12,050 MW in that same hour. In this hour, the RAA relies upon 50 MW of physical supply to operate at levels above what cleared in the day-ahead market.
[194] See Section 3.3 for more information on high levels of demand clearing in the day-ahead market.

2020 through 2024 is shown in Figure 3-23 below.[195] The figure also specifies which portion of the output was out-of-rate, based on offer segments priced above the LMP.

Figure 3-23: Average Hourly Energy Output from Reliability Commitments



The total amount of reliability commitments remained low in 2024, with an annual hourly average of only 10 MW of reliability commitments. At a system level, reliability commitments declined significantly after 2021 when transmission upgrades in Maine and Southeastern Massachusetts (SEMA) were completed. Furthermore, the few reliability commitments were mostly in-rate, limiting reliability uplift payments.

System operators may posture units—reducing their output below economic dispatch levels—to maintain operating reserves under stressed system conditions or to conserve limited stored fuel. When this occurs, resources are compensated through uplift payments for following operator instructions. In recent years, posturing was most commonly applied to pumped storage hydro resources; however, its use declined sharply after 2021 due to changes in operating practices. In 2024, no resources were postured.

3.4.3 Load Forecast and Market Implications

The ISO's day-ahead load forecast, published around 9:30am, is the last load projection prior to the close of the day-ahead market for the next operating day.[196] The load forecast was not a direct input into the day-ahead market up until recently when the joint day-ahead energy and ancillary services market (in March 2025) incorporated the load forecast as a constraint to be met in the market clearing engine. However, up to that point the ISO load forecast nonetheless

[195] For more information on reliability commitments reviewed by the IMM, see *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

[196] Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. See ISO's *Three-Day System Demand Forecast* page, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast

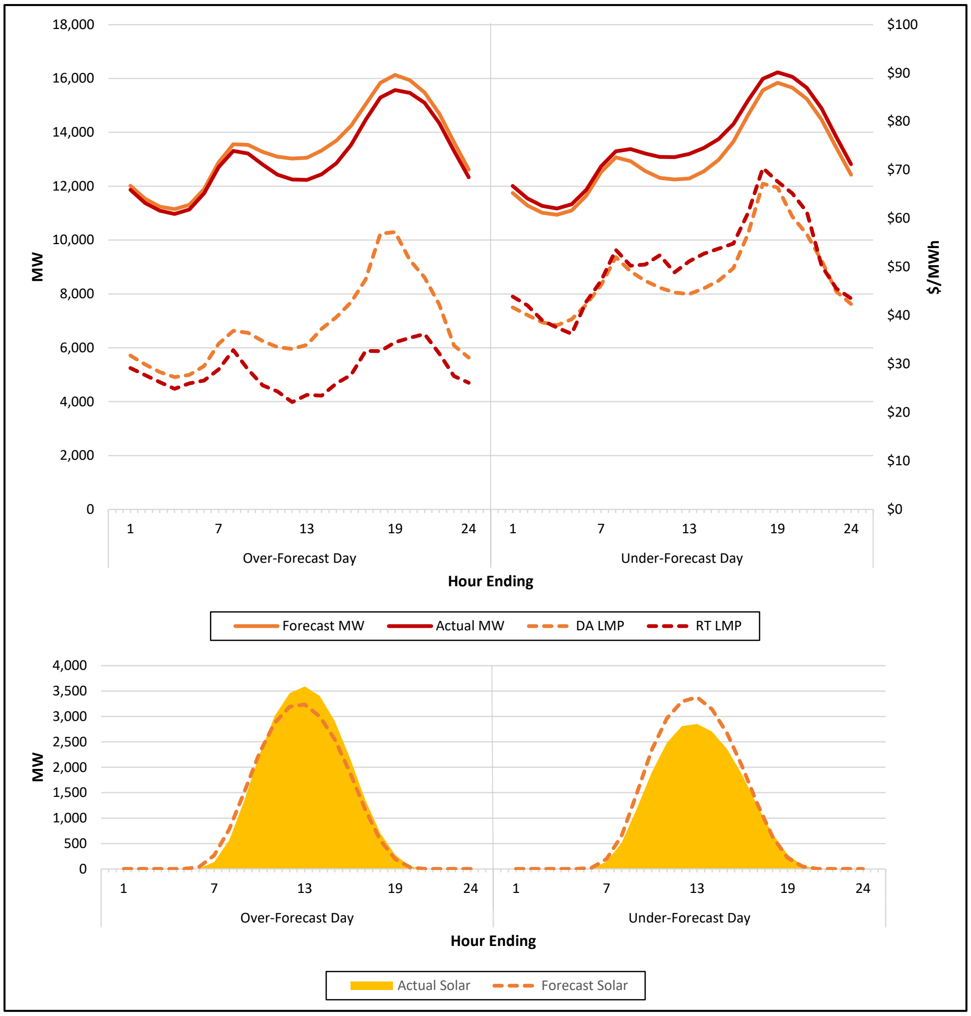
informed Load Service Entities' (LSEs) submission of day-ahead demand bid quantities.[197, 198] Therefore, LSE day-ahead demand clearing relative to their real-time load generally aligns with the ISO forecast error. Consequently, the day-ahead load forecast error has implications for both generator commitments and price deviations between the day-ahead and real-time markets.

Load Forecast Accuracy

Trends in load forecasting accuracy are covered in Section 1.5 , which concludes that the distribution of the load forecast error in 2024 was consistent with prior years. The continued growth in BTM[199] solar generation in recent years adds to the complexity of load forecasting, and the ISO has invested significantly in enhancing its load forecasting tools.[200] Figure 3-24 illustrates the relationship between solar forecast error, load forecasts, and LMP deviations by displaying the load curves of typical over- and under-forecast days, with load on the left axis, LMPs on the right axis, and solar forecasts below.[201]

[197] Load Serving Entities (LSEs) may also rely on their own in-house or third-party forecasting tools to inform their day-ahead bidding strategy.
[198] Additionally, as mentioned in Section 3.4, the load forecast is used in the RAA process to finalize the ISO's next day operating plan.
[199] The ISO includes both behind-the-meter solar and front-of-the-meter settlement-only (SOG) solar in its operational solar forecasts.
[200] In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see ESIG's article *Building data intelligence for short-term load forecasting with behind-the-meter PV,* by Jon Black, (March 27, 2019), available at https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/
[201] The average over-forecast and under-forecast days in the graph are calculated from the days with the top 25% largest over- and under-forecast load deviations in 2024.

Figure 3-24: Impact of BTM Solar on Load Forecast Error



Over-forecast days, when the day-ahead forecast is greater than actual real-time load, are typically driven in part by more load-reducing BTM and settlement-only solar generation than anticipated. This forecast error has a knock-on effect on LMPs, where the high day-ahead load forecast can result in more day-ahead unit commitments and higher LMPs and subsequent low LMPs in real time as units are dispatched down.

The opposite effects occur on under-forecast days, which are typically driven by less load-reducing solar generation than expected. Real-time LMPs are typically higher than day-ahead prices, driven by the costs of dispatching units up to meet unexpected demand, fast-start pricing as more units are committed to meet load, or reserve pricing as upward dispatch reduces available reserves.

3.5 Net Commitment Period Compensation (Uplift)

NCPC are make-whole payments made to generators, external transactions, and virtual transactions when they follow ISO dispatch instructions and experience revenue shortfalls or lost opportunity costs. NCPC payments can provide insight into unpriced energy costs, and higher levels of uplift may be symptomatic of price formation or missing product issues. In this section, we review NCPC in the context of total energy payments, provide a breakdown of payments by category, and show NCPC payments by generator type.

Key Takeaways

Uplift totaled $35 million ($0.30 per MWh of load) in 2024, comprising 0.6% of total energy market costs and consistent with prior years. Most NCPC payments ($26 million, 75%) occurred in the real-time market and were made to resources committed in economic merit order to meet load and reserve requirements.

Although fast-start pricing mechanics reduce NCPC payments to fast-start generators, these resources still frequently receive NCPC payments to cover their full operating costs. Real-time economic payments to fast-start units totaled $13 million (36% of total NCPC) in 2024. However, NCPC payments in 2024 did not indicate persistent price formation concerns.

Payment to day-ahead virtual and external transactions ($2.4 million) increased significantly in 2024 as a result of more frequent congestion at external interfaces. These uplift costs are settled between market participants and do not result in NCPC charges to load or day-ahead/real-time deviations.

NCPC in the Context of the Energy Market Payments

Tracking NCPC payments relative to energy payments provides a high-level metric capturing reliance on compensation through make-whole payments rather than uniform market clearing prices, as well as the level of costs borne by payers of uplift, which can be difficult to predict and hedge. Energy and NCPC payments are summarized in Table 3-7 below.

Table 3-7: Energy and Uplift Payments

	2020	2021	2022	2023	2024
Energy Payments ($ millions)	$2,996	$6,099	$11,712	$4,537	$5,624
NCPC Payments ($ millions)	$25.95	$35.94	$53.08	$34.39	$34.72
NCPC in $/MWh	$0.22	$0.30	$0.45	$0.30	$0.30
NCPC as % Energy Payments					
Day-Ahead NCPC	0.3%	0.3%	0.1%	0.1%	0.1%
Real-Time NCPC	0.5%	0.3%	0.3%	0.7%	0.5%
Total NCPC as % Energy Costs	**0.9%**	**0.6%**	**0.5%**	**0.8%**	**0.6%**

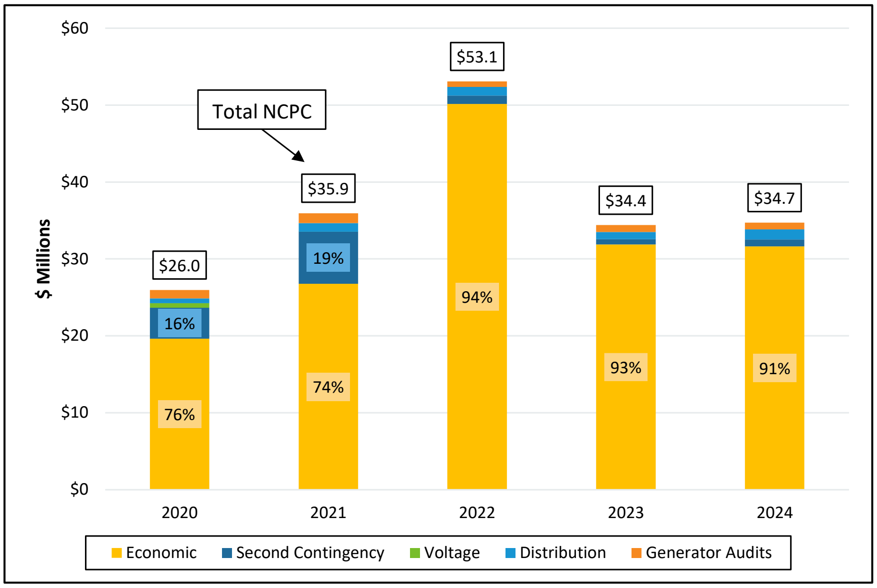
NCPC payments totaled $34.7 million in 2024, similar to total payments from 2023, comprising 0.6% of energy market payments, down slightly from 2023. Real-time NCPC payments continued to comprise the majority of total NCPC payments.

It is also important to note that payments under the Mystic Cost of Service (CoS) agreement (not included in the table above or figures below) are also a form of uplift payments to compensate generators outside of the capacity market for providing fuel security reliability services. In 2024, these costs were more than four times higher than energy uplift payments, at $139 million, or $1.19/MWh of load.

NCPC Payments by Category

NCPC payments are sorted into categories based on the underlying driver of the commitment or dispatch decision, including meeting system-wide first-contingency requirements (economic NCPC), local second-contingency, distribution or voltage requirements, and dual-fuel auditing requirements. Annual NCPC by category is shown in Figure 3-25 below.

Figure 3-25: Total Uplift Payments by Year and Category

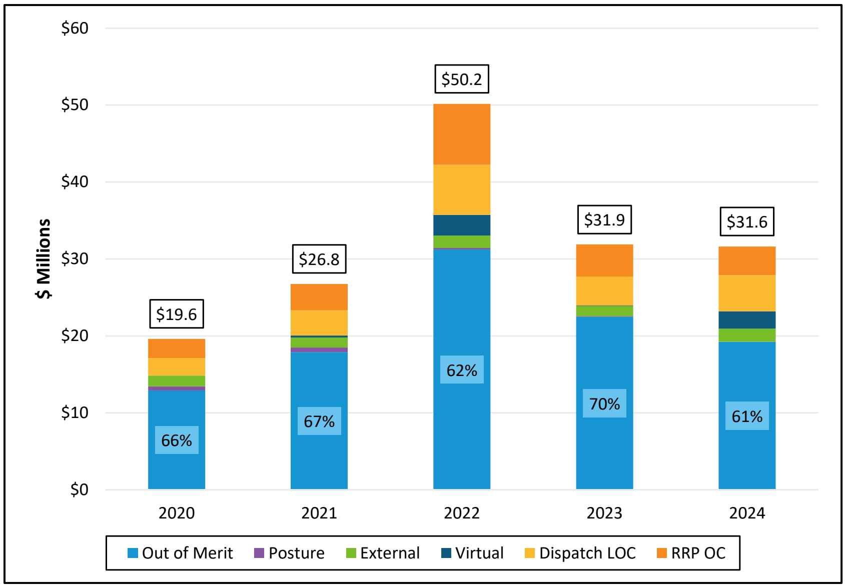


Economic (or First Contingency) NCPC comprised the largest share (91%) of annual NCPC payments at $32 million. Total economic NCPC remained similar to the prior year with trends and drivers discussed below. Second contingency payments were less than $1 million as relatively few reliability commitments were needed in 2024 (see Section 3.4.2.). Distribution payments ($1 million) occur most frequently in summer months due to local distribution system needs associated with high loads, and such payments are charged to the transmission owners or distribution companies that require special constraint resource operation. NCPC associated with generator audits totaled less than $1 million.

Economic NCPC by Subtype

Economic NCPC payments contain sub-categories, including out-of-merit payments for unrecovered generation costs, posturing uplift, external transaction payments, and compensation for lost opportunity costs due to the dispatch or rapid-response pricing process. Economic NCPC by subtype is shown in Figure 3-26 below.

Figure 3-26: Economic Uplift by Sub-Category



Out of merit payments, which cover any revenue shortfalls of generators committed to meet load and reserve requirements, continued to comprise the largest share of economic NCPC at $19 million. Out of merit payments are most frequently paid to cover the commitment costs of units that do not recover startup and no-load costs in the day-ahead market or fast-start units in the real-time market.

Fast-start commitment payments typically make up the majority of out of merit NCPC payments, totaling $13 million in 2024 (66% of total out of merit NCPC). While fast-start pricing mechanics reduce NCPC payments to fast-start units by reflecting their commitment costs in energy market offers, fast-start units might still require uplift payments when LMPs do not ultimately support their operating costs throughout their commitment. Out of merit NCPC declined from 2023, when pumped-storage unit outages led to relatively frequent commitment and uplift payment to oil-fired fast-start generators.[202]

Payments to virtual transaction increased to $2 million in 2024. Payments to virtual and day-ahead external transactions increased due to relatively frequent congestion at external interfaces (see Section 4).[203] Such payments maximize welfare without creating additional NCPC charges for load.

The two largest forms of opportunity cost payments (dispatch opportunity and rapid-response opportunity costs) totaled $8 million, a similar share of economic NCPC to prior years (27%). There were no posturing actions or resulting uplift in 2024.

[202] For more information on 2023 NCPC payments, see last year's *2023 Annual Markets Report* (May 24, 2024), Section 3.5, available at https://www.iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf.

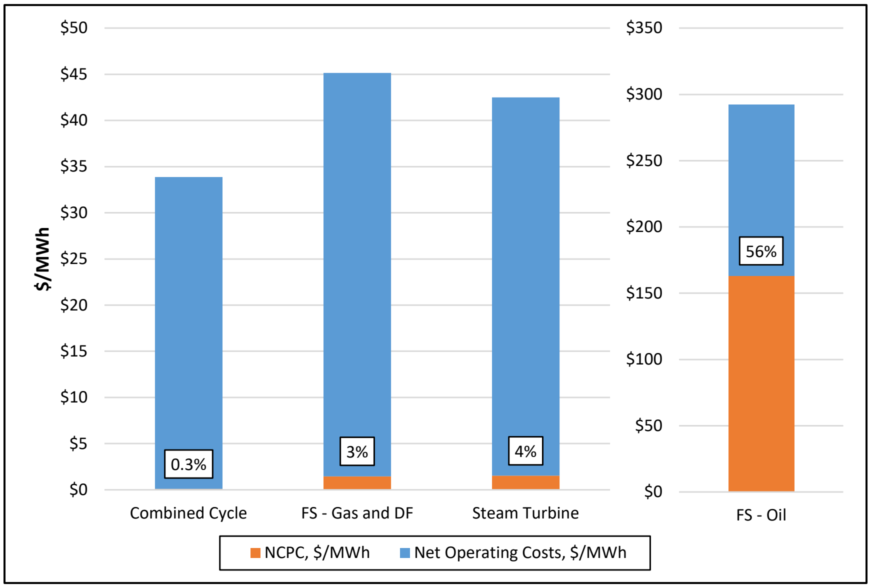
[203] For a numerical example of day-ahead virtual or external NCPC driven by congestion at external interfaces, see the ISO's *FAQs: Net Commitment-Period Compensation (NCPC)* page, available at https://www.iso-ne.com/participate/support/faq/ncpc-rmr

NCPC Reliance

As discussed above, high reliance on uplift payments for cost recovery might be indicative of poor price formation or might indicate other structural issues that lead to out-of-merit operation, such as out-of-market reliability commitments and dispatch.

Here, we define NCPC reliance as the share of total operating costs recovered through uplift payments.[204] Figure 3-27 below shows NCPC reliance for select fuel types. [205]

Figure 3-27: NCPC Reliance by Fuel Type



Combined cycle generators, both gas and dual-fuel, required uplift to recover less than 1% of their offered operating costs in 2024. Prices generally supported the operating costs of efficient combined cycle generators, which totaled roughly $35/MWh. Gas and dual-fuel fast-start generators (primarily combustion turbines and internal combustion generators) required uplift to recover 3% of their operating costs, which totaled $45/MWh. Steam turbine generators received $1.52/MWh in uplift payments, representing 4% of total operating costs. Oil-fired fast start generators recovered significant shares of their operating costs through uplift payments (56%). Such units operated infrequently due to their high costs ($290/MWh on average). Oil-

[204] For the purposes of calculating NCPC reliance, operating costs (the denominator of NCPC reliance) are calculated as the sum of energy, startup, and no-load costs that are eligible for recovery through either energy market revenues or uplift. Offered costs may be negative, and resources that are self-scheduled are treated as if they have negative offered commitment costs. This calculation sums the maximum of each generator's offered operating costs and zero to only include positive operating costs. Additionally, this calculation includes all day-ahead and real-time incremental NCPC and NCPC costs for non-fast start generators, and only real-time NCPC and NCPC costs for fast start generators. Day-ahead NCPC and costs for fast-start units are not included since day-ahead commitments for fast-start units are not binding. For more information on NCPC cost calculation rules, see *Section III Market Rule 1 Appendix F Net Commitment Period Compensation Accounting*, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_f.pdf.

[205] In this figure, NCPC and net operating costs are expressed in $/MWh of real-time generation. Net Operating Costs represent the share of operating costs that can only be recovered through energy market revenues.

fired fast-start generators relied on NCPC to a similar degree as in prior years, and received $4 million total in uplift payments.

The primary driver of out-of-merit NCPC reliance for fast-start capable gas, dual-fuel, oil, and other generator types is the frequency of fast-start commitments. While fast-start pricing mechanics reduce NCPC payments for fast-start generators, they might not recover their commitment costs if LMPs fall while they are still in minimum run time, or if they are committed to satisfy out-of-market system reliability needs.[206]

In summary, NCPC payments in 2024 remained roughly comparable to prior years. Economic payments to fast-start generators committed in real time continued to comprise a significant share of total uplift. NCPC payments in 2024 did not indicate persistent price formation concerns.

3.6 Summary of System Events During 2024

System events, such as tight system conditions resulting from generator outages or higher than anticipated loads, can have a significant impact on energy market outcomes. Two events warrant mention in 2024: the June 18 and August 1 capacity scarcity conditions (shortage events). This section details the frequency of system events and abnormal conditions over the past five years and provides a summary of the shortage events.

Key Takeaways

Overall, there were few instances of tight system conditions or scarcity pricing in 2024. These events were transitory in nature, and relatively small operating reserve deficiencies (compared to the requirement) were resolved quickly. During these periods, the markets provided transparent and strong price signals that incentivized supply resource performance.

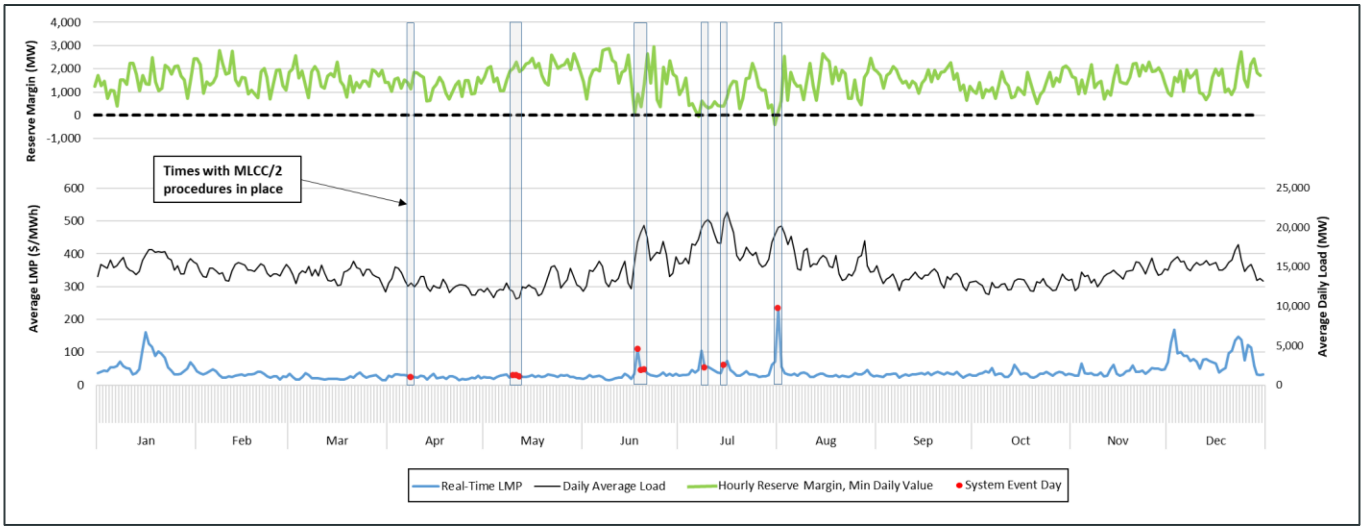
Weather and unplanned supply outages were the main drivers behind notable system events over the last several years. Two reserve shortage events and six M/LCC 2 events occurred during 2024. Both shortage events occurred on hot summer days and resulted from a combination of high loads and unplanned generator outages. Most M/LCC 2 events also occurred during the summer, with the exception of the April 8 and May 10-12 events which were declared due to a solar eclipse and a geomagnetic storm, respectively.

Overall, these outcomes reflect a system that has had a healthy reserve margin, on average, with few periods of system stress in the past few years.

To provide context for the events covered in this section, Figure 3-28 below overlays the timing of the two events discussed above and M/LCC2 (represented by the red dots) events on a series of average daily real-time LMPs and load levels. Also shown is the minimum total reserve margin (for an hour) for each day.

[206] System reliability requirements are described in ISO operating procedures. For example, see *Procedure: Manage Resource and Demand Balancing*, available at https://www.iso-ne.com/static-assets/documents/2015/02/sop_rtmkts_0080_0050.pdf

Figure 3-28: Pricing, Demand and Reserve Margin during System Events in 2024



The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years:

- Number of OP-4 and M/LCC 2 Events
- Reserve Deficiency Events
- Frequency of Extreme Hub LMPs

OP-4 and M/LCC 2 Events

The ISO uses the following control room procedures to address issues and alert participants during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)[207]
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)[208]

The number of instances for each type of event during the reporting period is shown in Table 3-8 below.

Table 3-8: OP-4 and M/LCC 2 Event Frequency

Procedure	2020	2021	2022	2023	2024
# of OP-4 Events	0	0	1	1	2
# of M/LCC 2 Events	3	6	6	6	6

[207] M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability. See the ISO's *Master/Local Control Center Procedure No. 2 (M/LCC2) Abnormal Conditions Alert*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[208] OP-4 establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure that the ISO can invoke as system conditions worsen. See *ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

The ISO implemented six M/LCC 2 events in 2024, the same amount as in 2021-2023. In our assessment of the system events, detailed in the quarterly reports, we generally found that the market performed well during these periods. The table at the end of this section summarizes the high-level causes and outcomes of each system event in 2024.

Reserve Deficiency Events

Reserve deficiency events (i.e., periods when there are negative reserve margins) are indicative of stressed system conditions when there is not enough available supply capable of meeting the region's 10- or 30-minutes reserve requirements. During such events, both reserve product and energy clearing prices reflect the reserve price cap associated with the deficient product, known as the applicable Reserve Constraint Penalty Factors (RCPFs). Below, Table 3-9 shows the number of hours during which each reserve margin was negative.

Table 3-9: Frequency of Negative Reserve Margins (System Level) [209]

Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative Spinning Reserve Margins
2020	0.0	0.0	14.5
2021	0.0	0.0	26.8
2022	1.4	0.1	48.1
2023	0.5	0.3	6.8
2024	2.2	1.1	3.7

Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years. The Total30 and Total10 margins fell below zero in 2022, 2023, and 2024, when tight system conditions led to capacity scarcity conditions under the Pay for Performance construct. During the 2024 capacity scarcity conditions, total reserve margins ranged from 154 to 577 MW below the requirement. No comparable events occurred during 2020 and 2021.

Shortages of ten-minute spinning reserves (with an associated RCPF of $50/MWh) occur more frequently reflecting demand for both energy and spinning reserves on committed dispatchable generation (mainly combined cycles). However, such occurrences were less frequent in 2023 and 2024 compared to the prior years due to a lower spinning reserve requirement. The spinning reserve shortages occurred across 18 days throughout the year in 2024 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages.

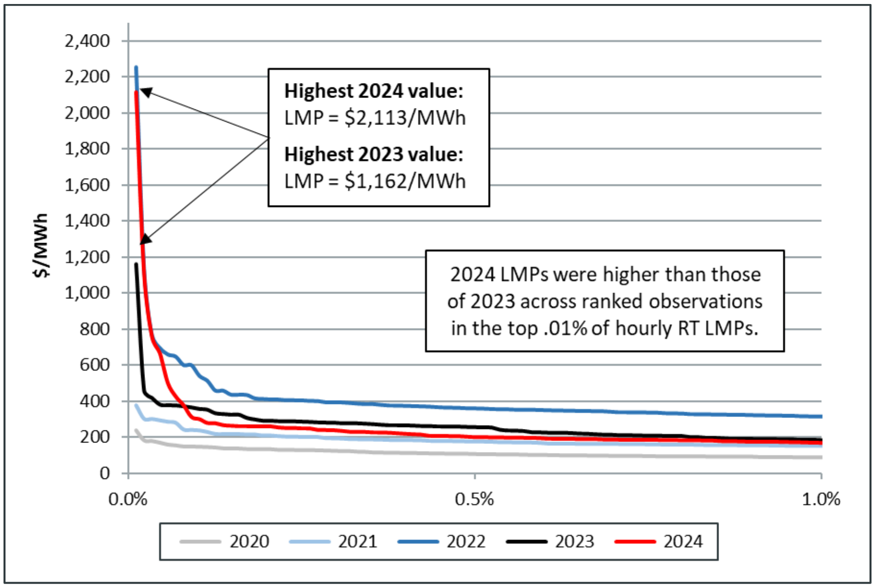
Frequency of Extreme Hub LMPs

High real-time LMPs can also be indicative of stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure

[209] The calculations in this table come from the LMP calculation processes in the real-time market software. The "Hours of Negative Total30 Margins" column does not include instances where only the replacement reserve margin is negative, because those instances are not associated with the $1,000/MWh RCPF.

3-29 below show the top 1% of hourly average real-time LMPs ranked from high to low over the past five years.

Figure 3-29: LMP Duration Curves for Top 1% of Real-Time Pricing Hour



Real-time LMPs in 2024 were similar to those of 2023 across most ranked observations besides the PFP event hours, consistent with the modest change in average LMPs. The four highest hourly real-time LMP values occurred on summer shortage event days; however, the majority of the top 1% of LMPs (58%) occurred during December 2024. Elevated energy prices during December were driven by high natural gas prices due to cold weather and pipeline constraints. There were no reserve deficiencies during this month.

The highest hourly price of the year ($2,113/MWh) occurred during HE 19 on August 1, when capacity scarcity conditions resulted in the RCPFs for the total ten-minute reserve constraint ($1,500/MWh) and total thirty-minute reserve constraint ($1,000/MWh) being incorporated into LMPs for portions of that hour.

Specific days that saw notable market and system outcomes in 2024 are summarized in Table 3-10 below.

Table 3-10: System Events In 2024

Date	Event Type	Driver	Market & System Summary
Apr 8	M/LCC 2	Solar eclipse	High solar output resulted in low loads during midday, followed by steepest hourly ramp on record (~4,000 MW/hr) during eclipse.
May 10-12	M/LCC 2	Geomagnetic storm	A severe magnetic storm resulted in the ISO taking steps to prepare the power grid for geomagnetically-induced currents. For example, certain transmission outages were delayed due to the conditions.
Jun 18-20	M/LCC 2, OP4 Actions 1 and 2 (Jun 18), Capacity Shortage Event (Jun 18)	Hot weather, high loads and generator outages	Loads were high due to hot weather. Multiple generator outages occurred throughout the day, including a trip during the evening peak. Operators made manual commitments. Capacity scarcity conditions for 30 minutes, and five-minute real-time LMPs peaked at $1,993/MWh.

Date	Event Type	Driver	Market & System Summary
Jul 9	M/LCC 2	Hot weather and high loads	High load forecast resulted in multiple supplemental commitments for the evening peak.
Jul 15	M/LCC 2	Hot weather and high loads	Low reserve margin expected going into the operating day due to high loads. There were multiple supplemental commitments for the evening peak, and non-spinning reserve pricing occurred during several hours in the late afternoon and evening.
Aug 1	M/LCC 2, OP4 Actions 1 and 2, Capacity Shortage Event	Hot weather, high loads and generator outages	Tight conditions expected due to weather conditions, and then a generator tripped shortly before the evening peak. Operators made manual commitments. Capacity scarcity conditions occurred during two separate periods in intervals beginning 16:55-17:00 and 17:45-19:20, and five-minute real-time LMPs peaked at $2,634/MWh.

3.7 Demand Response Resources

Demand Response Resources (DRRs) participate into the day-ahead and real-time energy markets by reducing end-use consumption. The first subsection (3.7.1) analyzes how DRRs participate in the day-ahead and real-time energy markets, and the second subsection (3.7.2) discusses capacity market participation. The third section (3.7.3) provides an assessment of DRR compensation across all markets.

Key Takeaways

In 2024, demand response market participation and outcomes followed trends observed in past years. DRRs primarily served as capacity and operating reserve resources available for dispatch at very high offer prices; 90% of DRR capacity was offered at $1,000/MWh in 2024. Given these high offer prices, dispatch of these resources occurred infrequently and at low quantities. DRRs mostly provided operating reserves during real-time operations; about 200 MW of 30-min reserves and just 2 MW of 10-min reserves per hour on average in 2024.

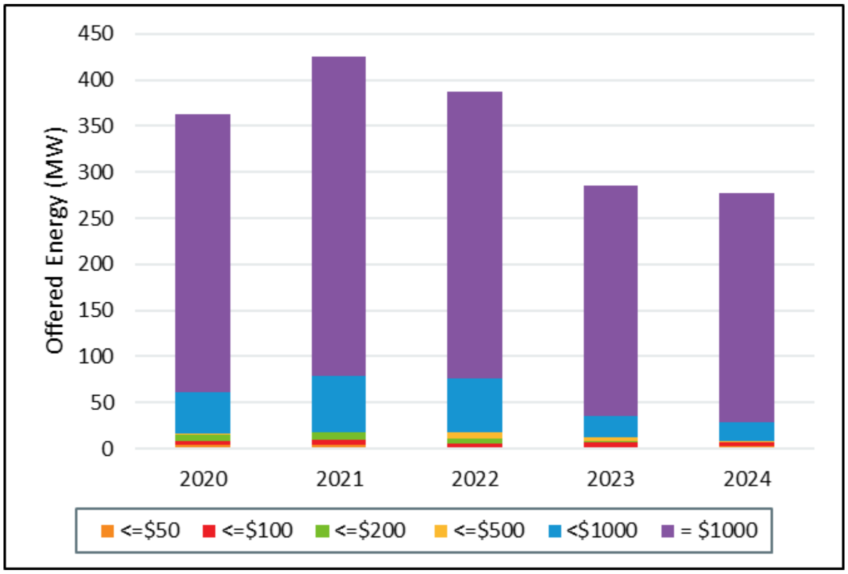
The capacity market continues to provide DRRs with the majority of overall market revenues; in 2024, DRRs received $16 million in capacity payments, which comprised 86% of their total market payments.

3.7.1 Energy Market Offers and Dispatch

By virtue of their high offer prices, most DRRs essentially function as reserve resources, providing energy in the real-time energy market only when prices are extremely high (~$1,000/MWh).[210] Figure 3-30 below indicates average hourly demand reduction offers in the real-time energy market, by year and by offer price category for energy offers for the past five years.

[210] Because these resources primarily function as a source of operating reserves and are infrequently committed in the day-ahead energy market, this section uses real-time offer and dispatch data to illustrate these resources' participation in the ISO's energy markets.

Figure 3-30: Demand Response Resource Offers in the Real-Time Energy Market



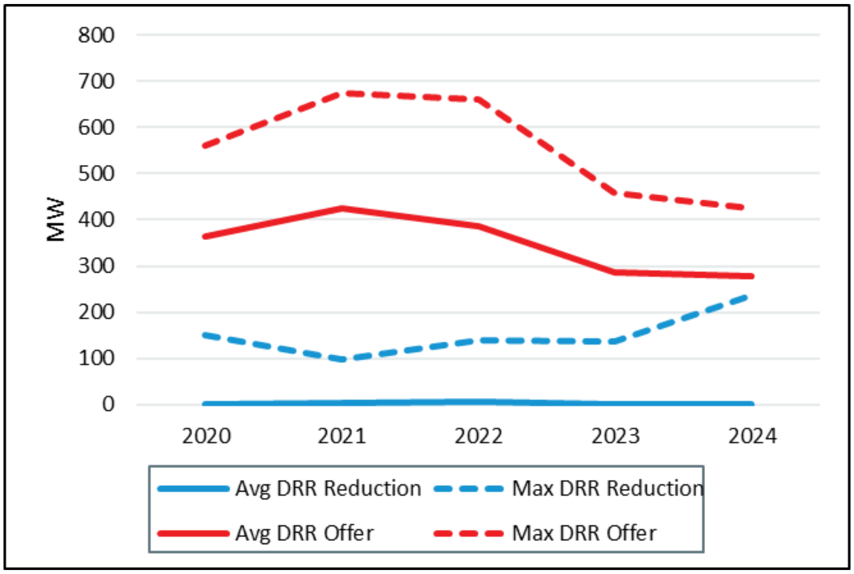
Most DRRs offer their real-time energy at $1,000/MWh; 90% of offered DRR capacity, on average, was offered at this value in 2024.[211] In most hours, only the lower-priced energy offers ($200/MWh or less) have a reasonable likelihood of being dispatched in the real-time energy market; these offers averaged just 2% of hourly offered DRR capacity in 2024.[212]

Given the pattern of offer prices for DRRs, the ISO dispatches relatively small quantities in the energy markets. Figure 3-31 below illustrates the reduction of DRRs in the real-time energy market relative to the resources' offered reductions over the past five years. The blue lines represent actual reductions, while the red lines indicate offered reduction capability.

[211] Prior to the implementation of market rule changes associated with FERC Order 831 (Offer Caps in Energy Markets) on 3/1/2020, $1,000/MWh was the highest energy offer price that could be submitted to the ISO. That cap was eliminated with FERC Order 831, with the addition of the requirement that any offered costs greater than $1,000/MWh be supported quantitatively by the participant and verified by the ISO. No DRR has offered greater than $1,000/MWh during the study period.

[212] Energy prices in the real-time market exceeded $200/MWh in just 1% of pricing intervals in 2024.

Figure 3-31: Demand Response Resource Reductions in the Real-Time Energy Market



DRRs were dispatched at high levels during the Capacity Scarcity Conditions that occurred during the summer of 2024, producing the highest observed maximum reduction value (237 MW) across the study period on June 18, 2024. On average, however, DRRs were dispatched to reduce consumption infrequently, averaging 1.1 MW of energy reductions across all hours in 2024. This is the lowest average reduction value in the study period, reflecting the fact that DRRs are generally not relied upon as a form of energy supply during normal operating conditions. DRR offer quantities into the real-time energy market continue to decline, as illustrated by the red lines in the figure. This trend aligns with declining demand response participation in the Forward Capacity Market.

As noted earlier, DRRs also provide operating reserves in real time. DRRs are considered fast-start capable, if those capabilities have previously been demonstrated.[213] In 2024, DRRs provided only 2.6 MW, on average across all hours, of ten-minute operating reserves,[214] but provided substantially more in thirty-minute operating reserves, averaging 200 MW. These reserve designation values are effectively unchanged from 2023.

3.7.2 Capacity Market Participation

Active demand response participates in the Forward Capacity Market by aggregating one or more DRRs into Active Demand Capacity Resources (ADCRs). In 2024, ADCRs had capacity supply obligations (CSOs) totaling approximately 408 MW. This continues the year-over-year trend of declining capacity market participation by ADCRs, and is a reduction of 28 MW (6%) compared to 2023.[215] All active demand resources with capacity market obligations are

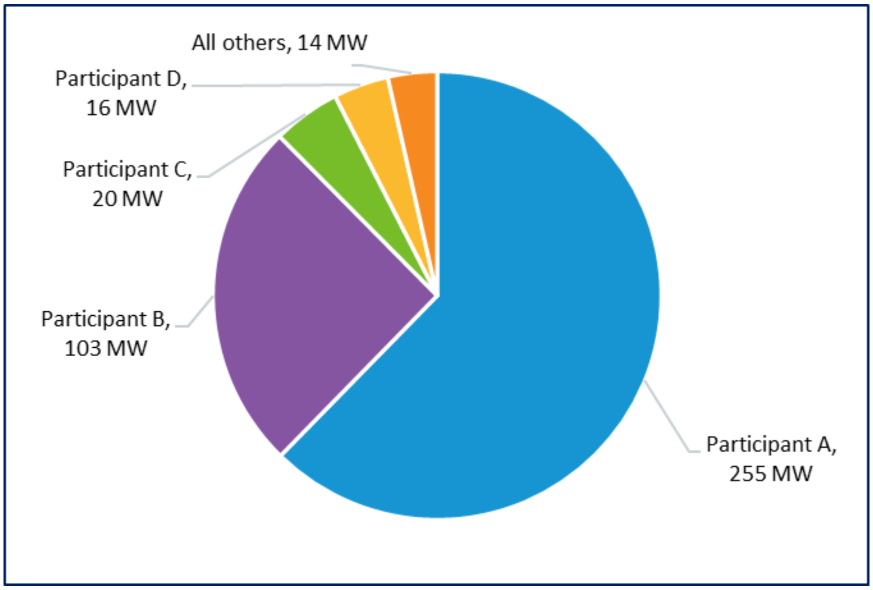
[213] To be designated during the operating day as providing thirty-minute fast-start reserves, a DRR must offer certain operating parameters consistent with fast-start operation. These operating parameters are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0 MW.

[214] While DRRs can provide ten-minute reserves, it is required that they have interval metering with granularity of one minute or less to do so.

[215] The CSO estimate indicates the average capacity supply obligation for the calendar year.

required to offer "physically available" capacity into the day-ahead and real-time energy markets.[216] Figure 3-32 indicates the CSO by participant for ADCRs.

Figure 3-32: CSO by Lead Participant for Active Demand Capacity Resources, 2024



Just six participants had CSOs in calendar year 2024, down from eight in the prior year. The two largest participants accounted for approximately 88% of ADCR capacity supply obligations.

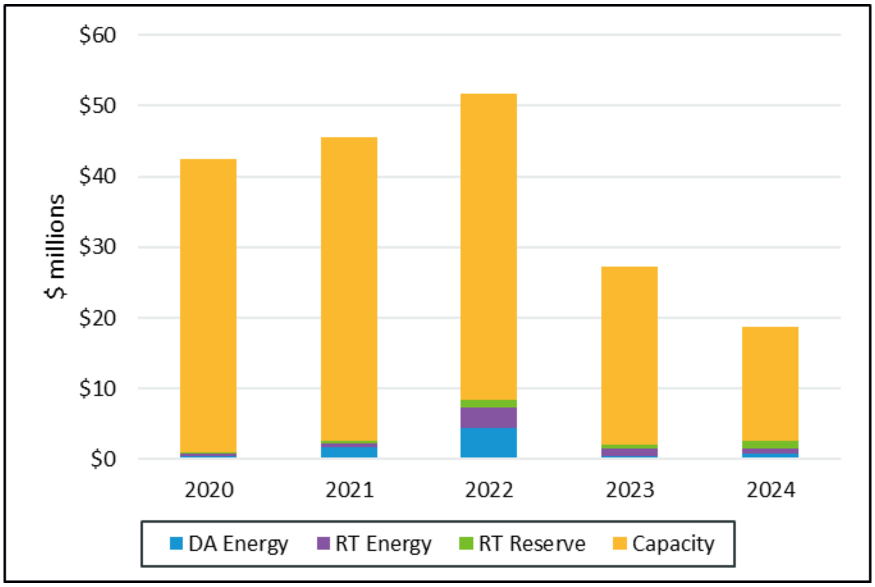
3.7.3 Wholesale Market Compensation

The capacity market continues to be the key driver of DRR compensation. DRRs have received relatively modest energy market compensation during the review period. This results from low dispatch rates in the energy market and infrequent TMOR pricing in the real-time energy market. Figure 3-33 provides a summary of capacity, energy, and reserve payments by month for the past five years.[217]

[216] The relationship between demand response resources (DRRs) and active demand capacity resources (ADCRs) is somewhat complicated. DRRs are mapped to ADCRs. More than one DRR can be mapped to an ADCR, which holds the capacity supply obligation. To satisfy the ADCR's capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR's capacity supply obligation.

[217] When dispatched, DRRs are eligible to receive uplift payments. NCPC provides additional compensation to resources when energy market revenues are insufficient to cover as-offered operating costs in the day-ahead and real-time energy markets. NCPC payments to DRRs are included within the DA and RT energy bars in this figure, and are not shown separately.

Figure 3-33: Wholesale Market Payments to Demand Response Resources



In 2024, capacity market payments to DRRs totaled $16 million, accounting for 86% of all DRR payments.[218] This reflects a decrease in capacity payments relative to prior years, as a result of both decreased DRR CSO and lower capacity prices. Payments for energy and reserves have remained relatively small. In 2024, total energy and reserve payments were $2.7 million, up 25% from 2023. This increase is consistent with the higher day-ahead and real-time LMPs and reserve prices observed throughout 2024, including those that occurred during the Capacity Scarcity Conditions in the summer.

[218] The FCM compensation estimate focuses just on the payments for the actual obligation on which these resources needed to deliver based upon the results of the primary FCA for the delivery period. It does not take into account any payment gains or losses that might have occurred from altering obligations through FCM bilateral and reconfiguration activities. This value also reflects Pay-for-Performance payments and penalties assessed to ADCRs.

Section 4
External Transactions

External transactions are energy market transactions that allow market participants to transfer power between New England and its neighboring control areas, and represent an important part of the overall supply and demand picture.[219] Transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas, and provide reliability benefits to the interconnected systems.

This section reviews trends in external transactions in the day-ahead and real-time energy markets. The first section (4.1) provides an overview of external transactions across all external interfaces, while the second section (4.2) looks specifically at the performance of Coordinated Transaction Scheduling (CTS) with New York.

4.1 External Transactions

This section on outcomes, trends and drivers of import and export (external) transactions is organized in three subsections: (4.1.1) overall flows between New England and its neighboring control areas, with a breakdown across the six interfaces, (4.1.2) the pattern of fixed bidding versus price-sensitive bidding, and (4.1.3) the drivers of uplift (NCPC) payments to external transactions.

Key Takeaways

Interchange Levels and Drivers: Real-time net interchange averaged 1,175 MW per hour, which was the lowest level of net interchange since 2011(when interchange averaged 1,150 MW per hour). Net interchange continued to decrease as dry weather in Canada limited sales of hydro generation to New England and a nuclear generator in New Brunswick took an extended outage. Nearly 60% of total net interchange came from Canadian interfaces, a decrease from over 80% in 2023.

According to the U.S. Energy Information Administration (EIA), 2023 saw a significant decline in electricity exports from Canada across both the Eastern and Western Interconnections with the United States, driven in part by reduced hydropower generation in Canada. Flows into MISO, NYISO and New England from neighboring Canadian provinces were substantially lower than historical levels. This trend persisted into 2024.

Contribution on High Load Days: Despite falling over the last five years, net interchange continues to play a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During days with high loads (> 20,000 MW) net interchange averaged nearly 2,700 MW per hour, which was higher than average net interchange on similar days over the prior four years (2,500 MW).

[219] A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

Priced vs. Unpriced: At the Canadian interfaces, most day-ahead transactions were priced during 2024. However, nearly all of these priced transactions were not re-offered in real time and therefore were effectively scheduled as fixed transactions in the real-time market. At the three New York interfaces, external transactions tended to be fixed in the day-ahead and priced in real time due to the mechanics of Coordinated Transaction Scheduling at New York North.

Uplift and Recommendation: External transactions received more uplift payments in the day-ahead market this year, largely due to increased payments to virtual transactions for relieving external congestion at the New Brunswick interface in the day-ahead market. In the real-time market, uplift payments increased slightly compared to 2023 as forecast error at non-CTS interfaces led to increased clearing of out-of-merit external transactions.

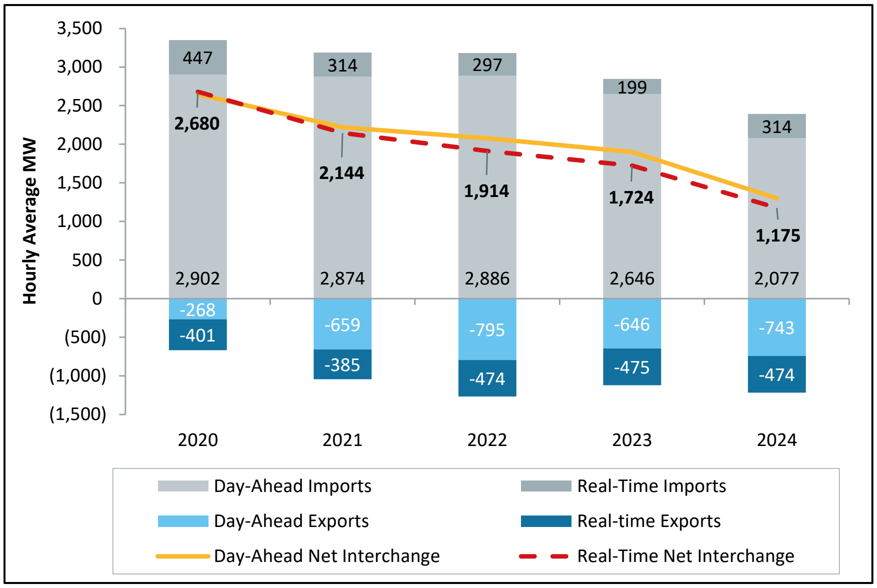
We recommend that ISO-NE review non-CTS external interface clearing rules to ensure participants are incentivized to offer external transactions that reflect expected quantities at the cost or value of the underlying energy. Despite the recent modification to the timestamp tiebreaker rule, the scheduling priority mechanics result in undesirable incentives as participants compete to submit offers 40 days in advance of delivery. In recent years, participants have found additional ways to gain scheduling priority, most notably through the use of virtual demand bids. While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time.

4.1.1 External Transaction Volumes

The average hourly system-wide net interchange from the day-ahead and real-time markets are shown in the line series of Figure 4-1 below. The bar series chart shows the hourly average imported volume (positive values) and exported volume (negative values), as well as the net interchange in both the day-ahead and real-time markets.[220]

[220] The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

Figure 4-1: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



Net interchange continues to decrease between New England and its neighboring control areas. Real-time net imports averaged 1,175 MW per hour (or 9% of real-time load), the lowest volume of net interchange since 2011. In 2024, net interchange fell as dry weather continued in Québec, and a nuclear unit in New Brunswick took an extended outage. Overall, day-ahead and real-time net imports fell by 666 MW and 549 MW on average, respectively.

Despite falling over the last five years, net interchange still plays a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During days with high loads (> 20,000 MW), net interchange averaged nearly 2,700 MW per hour, which was higher than average net interchange on similar days over the prior four years (2,500 MW).

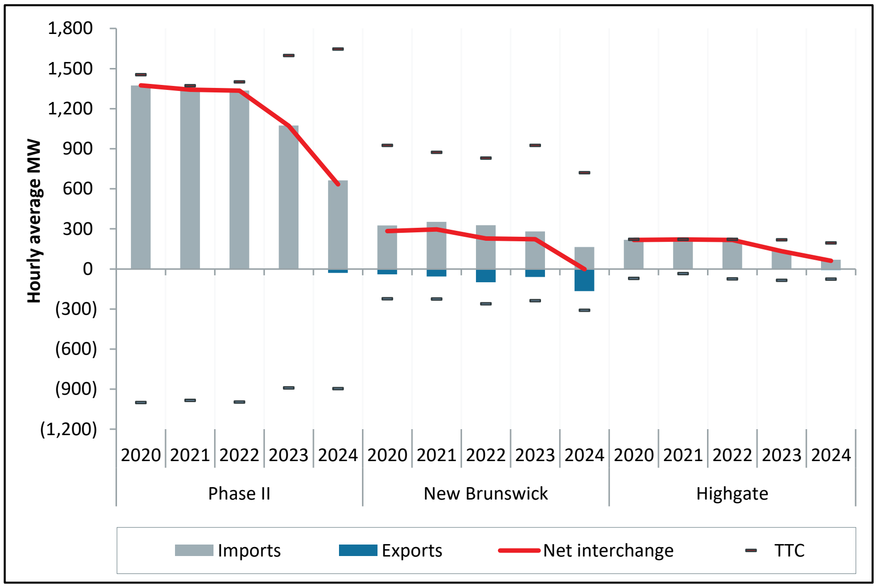
The close proximity of day-ahead net interchange (orange) and real-time net interchange (red) line series highlights that day-ahead market outcomes across the external nodes align well on average with real-time scheduled flows (historically within 2%).[221] However, average real-time net interchange remained significantly lower than day-ahead net interchange in 2024 by 10% (or 124 MW), which was similar to 2023 (9%). Additional real-time exports over the New York North interface and reductions of real-time imports at Highgate kept real-time net interchange below day-ahead cleared levels. When net real-time interchange is lower, New England must commit additional real-time native generation which can lead to higher real-time prices.

[221] Virtual transactions cleared at external interfaces in the day-ahead market are included in the day-ahead net interchange value. In the day-ahead energy market, virtual supply and demand are treated similarly to imports or exports.

A Breakdown of Flows across the Canadian Interfaces

Annual hourly average real-time net interchange volumes (red line), as well as the gross import and export volumes, are shown in Figure 4-2 below, along with the real-time total transfer capability (TTC) ratings for each interface.[222]

Figure 4-2: Real-Time Net Interchange at Canadian Interfaces



According to the U.S. Energy Information Administration (EIA), 2023 saw a significant decline in electricity exports from Canada across both the Eastern and Western Interconnections with the United States, driven in part by reduced hydropower generation in Canada.[223] Flows into MISO, NYISO and New England from neighboring Canadian provinces were substantially lower than historical levels. This trend persisted into 2024.

The net interchange between New England and Canada saw another substantial fall as 1) dry weather persisted in Canada, limiting the amount of excess hydroelectric generation to sell in New England [224], and 2) an extended outage of a large nuclear generator in New Brunswick limited the amount of generation and capacity in New Brunswick.[225] The generator represents a large portion of native generation within New Brunswick and the outage led to increased demand for New England exports. Despite falling import volumes, Canadian interfaces still accounted for 59% of total net imports into New England.

Over the last two years, net imports decreased at Highgate and Phase II, the two interfaces connecting New England to Québec. Phase II saw the highest net imports of any interface from

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[222] The total transfer capability (TTC) rating is the MW amount of power that can be reliably transferred from one system to the other over the transmission interface.

[223] See *U.S. electricity exports to Canada have increased since September 2023*, (November 12, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=63684

[224] For more information on Québec's reduction in exports, see Hydro-Québec's *Annual Report 2024*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/M1029-22024G415-rapport-annuel-2025-03-en.pdf

[225] For more information on the outage of the New Brunswick nuclear generator, see *Point Lepreau Nuclear Generating Station Returns to Operation* (Dec 12, 2024), available at: https://www.nbpower.com/en/about-us/news-media-centre/news/2024/point-lepreau-nuclear-generating-station-returns-to-operation/

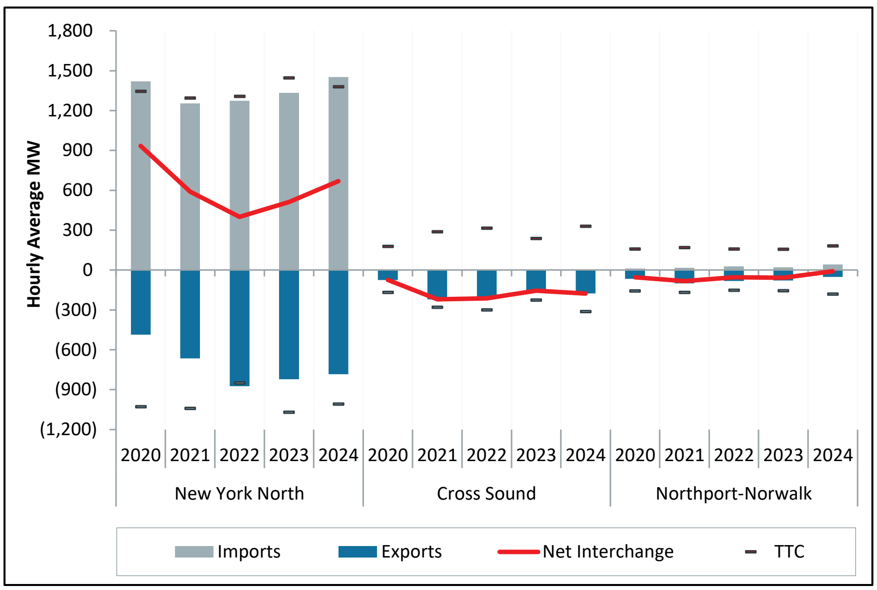
2020 to 2022, averaging 1,351 MW per hour. However, in 2024, net imports at Phase II averaged 633 MW per hour, 53% below average levels from 2020 to 2022. Historically, imports at the Highgate interface had been close to the maximum import capability of the interface (225 MW). In 2024, net imports decreased for the second consecutive year, averaging just 61 MW per hour.

In New Brunswick, a nuclear generator took an extended outage that lasted from April 2024 to December 2024. When the unit was in-service, New England was a net importer over this interface, averaging 178 MW per hour. During the outage, New England exported over 80 MW per hour, on average.

A Breakdown of Flows across the New York Interfaces

Real-time interchange volumes and capabilities for each of the three New York interconnections are shown in Figure 4-3 below.

Figure 4-3: Real-Time Net Interchange at New York Interfaces



On a net basis, New England imports power over the New York North interface and exports power to Long Island over both the Cross Sound Cable and Northport-Norwalk interfaces. Combining flows at all three interfaces, ISO-NE net imports averaged 483 MW per hour (or 4% of total real-time load).

At New York North, net interchange (red line) increased for the second consecutive year partially offsetting the drop in Canadian imports. Net interchange continued to increase following the completion of transmission work in the New York control area in 2022. In the day-ahead market, prices remained close between New York and New England. In 2024, New York prices were $0.74/MWh higher than New England compared to $0.65/MWh in 2023. External transactions may be willing to flow from New York to New England at a financial loss to deliver on contracted energy or to sell Renewable Energy Certificates (RECs) at a higher price in New England.

New England typically exports power to Long Island over the Cross Sound Cable and Northport-Norwalk interfaces. In 2024, *net exports* at Cross Sound Cable averaged 177 MW per hour. At Cross Sound Cable, only one participant can clear real-time export transactions since they hold all of the reservation rights at the interface.[226] At Northport-Norwalk, net exports averaged 9 MW due partly to congestion in southwestern Connecticut limiting flows across the interface (export constrained area).

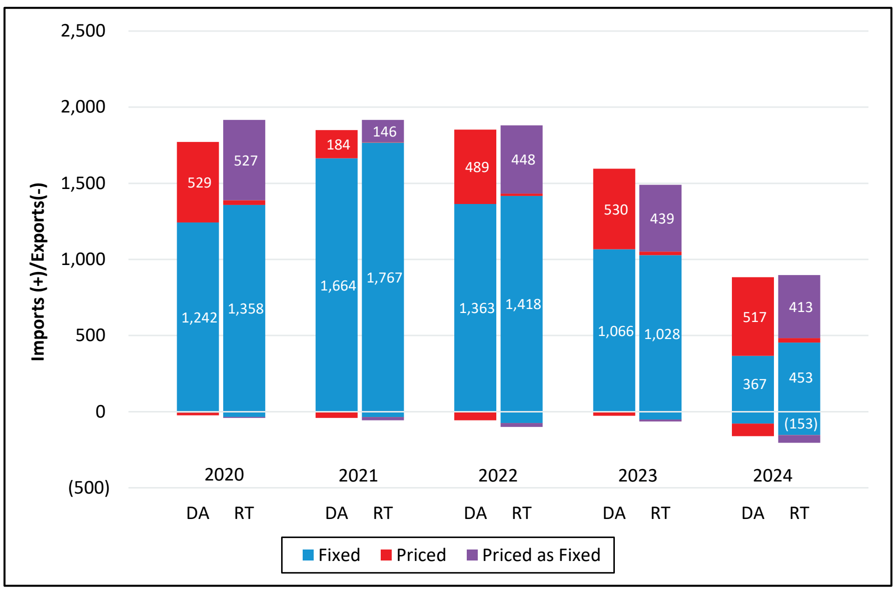
4.1.2 External Transaction Participation

In Section 3, we assessed overall market supply and demand-side participation in terms of the extent to which supply offers, or demand bids are price-taking (fixed) versus price-making (priced). This can have important implications for price formation in the energy markets. In this section, we present a similar analysis focusing on external transactions, which participate on both the supply and demand sides of the market (i.e., supply offers for imports and demand bids for exports).

Canadian Interfaces

The composition of transactions that *cleared* at the Canadian interfaces in the day-ahead and real-time markets by fixed, priced and "priced as fixed"[227] is shown in Figure 4-4 below.

Figure 4-4: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)



In the day-ahead market external transactions have been predominantly fixed at Canadian interfaces. However, levels of fixed import transactions have fallen at Canadian interfaces in recent years in tandem with an overall decline in total import transactions. Day-ahead priced transactions remained relatively consistent over the last three years.

[226] The Cross Sound Cable interface requires transmission reservations to clear external transactions at this interface. One participants holds the transmission reservations.

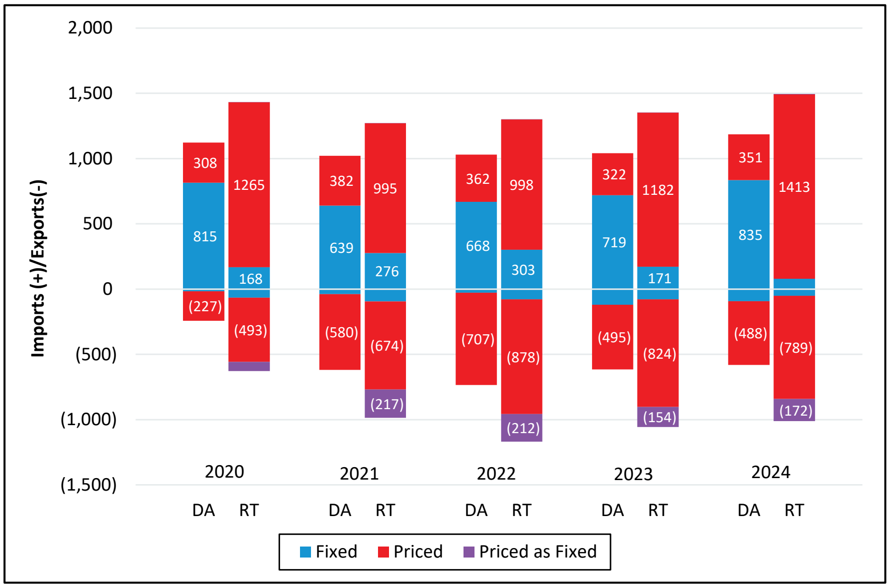
[227] A "priced-as-fixed" transaction is a real-time external transaction that was priced and cleared in the day-ahead market, but not reoffered in the real-time market. When day-ahead priced transactions are not reoffered in the real-time market, they are scheduled as fixed transactions.

There continues to be very low levels of price-sensitive transactions in the real-time market. At the Canadian interfaces, most priced transactions were not reoffered in real time. Without these transactions being reoffered, nearly all real-time transactions are scheduled as fixed ("Priced as Fixed" label).

New York Interfaces

The composition of transactions that cleared at the New York interfaces in the day-ahead and real-time markets by fixed, priced and "priced as fixed" is shown in Figure 4-5 below.[228]

Figure 4-5: Transaction Types by Market and Direction at New York Interfaces (Average MW per hour)



Most day-ahead cleared import transactions at the New York interfaces were fixed while most exports were priced. In 2024, the composition of external transactions at New York interfaces remained similar to levels in 2023. Day-ahead price differences between New York and New England stayed relatively flat year-over-year, with New York prices averaging just $0.74/MWh higher than New England prices at New York North, the largest interface connecting New York and New England.

In real time, most transactions are priced due to the bidding mechanics of Coordinated Transaction Scheduling (CTS) at the New York North interface. Under CTS, all real-time transactions are evaluated based on price, although participants may offer prices as low as negative $1,000/MWh, which effectively schedules the import transaction as fixed. Most real-time import transactions that cleared in the day-ahead market continued to be price-insensitive at the interface. Transactions can be fixed in real time at New York North, but these represent wheeled transactions.[229]

[228] Volumes not listed in the figure all averaged less than 100 MW per hour.
[229] A wheeled transaction occurs when a participant flows power from one system to another over a third party's transmission lines. For example, a participant might use these transactions to flow power from PJM through New York and into New England.

4.1.3 External Transaction Uplift (NCPC) Payments

External transactions are eligible to receive uplift (or NCPC) payments when revenues are not sufficient to recover their costs. These payments often occur in the real-time market when external transactions clear on an ISO price forecast but are unable to recover as-offered costs through actual settled prices. External transactions (or virtual transactions placed at external nodes) can also receive uplift in the day-ahead market for relieving congestion at non-CTS external interfaces since congestion is not captured in the LMP. These payments occur when a transaction that is out-of-the-money at the system price clears in the direction counter to the constraint (e.g., an export or virtual demand bid when the interface is import-constrained) allowing a counter-party to clear in excess of the interface limit.[230] These otherwise uneconomic transactions require uplift in the absence of congestion pricing.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets are presented in Table 4-1 below.

Table 4-1: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2020	$0.0	$1.4
2021	$1.0	$0.5
2022	$3.1	$1.2
2023	$0.1	$1.3
2024	$2.4	$1.6

Typically, total uplift paid at external nodes is very small compared with other types of uplift (see Section 3.5). In the day-ahead market, these payments typically occur due to congestion; specifically, when there is a surplus of infra-marginal external or virtual transactions in excess of the TTC, and virtual or priced external transactions provide "counter-flow."[231] In 2024, *day-ahead* uplift credits totaled $2.4 million, much higher than the prior year. During the outage of a nuclear unit in New Brunswick, this interface was frequently constrained due to high-priced or fixed export transactions in excess of the TTC. Virtual supply and import transactions received day-ahead uplift for relieving this constraint. To receive uplift, these bids must be priced above the LMP, but below the price of the excess export transactions.

Real-time uplift credits are driven by transactions scheduled out-of-rate due to price forecast error. In other words, transactions (at non-CTS interfaces)[232] were in-rate based on forecasted prices, but were out-of-rate based on actual prices that are used in settlements. Accurate price

[230] For example, consider an interface with an import TTC of 100MW and an LMP of $100/MWh. If there are 200MW of imports offered at $0/MWh, only 100MW can clear (due to the TTC), unless there is a transaction to offset the remaining 100MW of excess imports. If a 100MW export is offered at $50/MWh, it can provide counter-flow. The $50/MWh exports are willing to purchase the $0/MWh imports. However, because congestion is not captured in the LMP, the energy settlement for the export will result in a loss; the exports are only willing to pay $50/MWh and the LMP is $100/MWh. Therefore, these 100MW of exports must be paid $50/MWh to make them whole, for a total NCPC payment of $5,000. The NCPC charges are only levied to the participants importing over the interface.

[231] At non-CTS external interfaces, NCPC charges and credits are a transfer between participants creating the congestion to participants relieving the congestion.

[232] At the CTS interface, out-of-rate transactions are not entitled to NCPC, but also do not incur NCPC charges.

forecasting of LMPs helps reduce NCPC paid to external transactions. In 2024, forecast error lead to similar NCPC payments compared to the prior two years.

4.1.4 Recommendation for the ISO to Review Clearing Mechanisms used at External Interfaces

Beginning in Winter 2022/2023, participants started using virtual demand transactions to gain real-time scheduling priority for imports at the Highgate interface. A participant can use virtual demand or export bids in the day-ahead market to provide counter-flow at an import-constrained interface, allowing additional imports to clear in the day-time market. When two identically priced bids clear in the day-ahead market at a constrained external interface, real-time priority is awarded to the first participant to submit their import transactions i.e. based on the timestamp of the submission. We recommend that ISO-NE review clearing mechanisms at external interfaces, particularly rules that incentivize submitting external transactions as early as possible. This would allow participants to re-offer external transactions closer to the operating day without losing priority.

We observed an increase in virtual transactions at the Highgate interface, particularly during the winter. Virtual demand bids increase in the winter because they are used in conjunction with increased import transactions from the same participant(s). While these virtual transactions provide a financial hedge for imports, they also can be used to ensure clearing priority at the interface. Real-time external transactions clear based on: 1) price, 2) day-ahead cleared volumes, and 3) time-of-submission (up to 40 days in advance). With a counter-flowing virtual demand bid and an early time of submission on the import transactions, a participant can clear their full day-ahead volume of imports and gain real-time scheduling priority.

Current Market Clearing Rules at External Interfaces

Market clearing logic at external (non-CTS) interfaces differs from the rest of the system in the real-time market. Specifically, when multiple participants compete for limited transmission capacity between New England and neighboring balancing areas, tie-breaking rules are used to determine which real-time import offers clear. Historically, one of the key tie-breakers has been the timestamp of the import offer—often submitted when the offer window opens 40 days in advance of the operating day. In recent years, participants have found additional ways to gain scheduling priority, most notably through the use of virtual demand bids.

While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time. Accordingly, we recommend that the ISO review the real-time scheduling rules at non-CTS external interfaces.

Table 4-2 below shows a simplified version of how ISO-NE clears external transactions at non-CTS interfaces.[233]

[233] The New York North interface uses Coordinated Transactions Scheduling. This interface includes congestion pricing while the other five interfaces do not. Congestion pricing helps incentivize participants to offer external transactions at cost, and virtual demand cannot be used to ensure scheduling priority at the CTS interface.

Table 4-2: Day-Ahead and Real-Time Clearing of External Interfaces[234]

Clearing Priority Ranking at External Interfaces (Steps)	Day-Ahead Market	Real-Time Market
1	Day-ahead economics/price	Real-time economics/price
2	Pro rata	Day-ahead cleared volumes
3		Timestamp of bid/offer with one-minute granularity[235]
4		Pro rata

In the day-ahead market, external interfaces clear based on price if the Total Transfer Capability (TTC) constraint is not limited. In the real-time market, bids also clear first based on price. However, there are several additional steps at non-CTS interfaces to receive scheduling priority if bids are offered at the same price, and the TTC is limited. In Step 2, priority is awarded to bids that cleared in the day-ahead market. In Step 3, bids clear based on the earliest time of submission. This incentivizes participants to compete to offer bids as early as possible, up to 40 days in advance of the operating day, to obtain an advantage with respect to scheduling priority.

In some cases virtual demand bids are also being used to ensure equal day-ahead cleared volumes between participants, meaning Steps 1 and 2 do not bind. Rather, the tie breaker logic moves to Step 3 whereby real-time priority is based on the earliest timestamp.

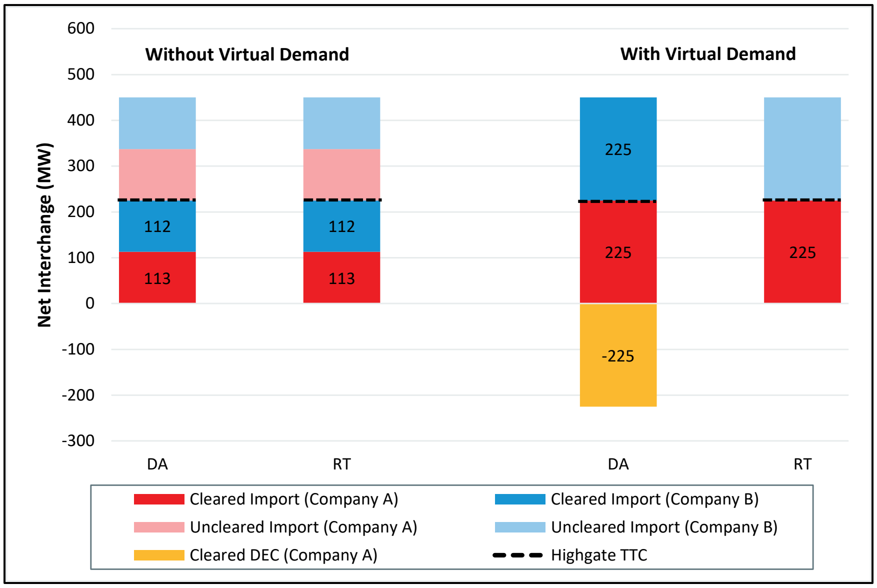
Examples of Clearing at the Highgate Interface

The examples in Figure 4-6 below show how a virtual demand bid impacts the clearing of external transactions when two participants offer fixed priced imports at 225 MW, the full TTC.

[234] For simplicity, this does not include clearing based on transmission service. At the Phase II and Cross Sound Cable interfaces, bids with firm transmission service will always receive the highest clearing priority in the real-time market. These transmission rights are awarded through an auction. For more detail on the clearing of external transactions, see ISO *New England Operating Procedure No. 9 Scheduling and Dispatch of External Transactions*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op9/op9_rto_final.pdf

[235] In 2023, participants submitted many bids as soon as the 40-day window opened overwhelming the ISO systems, prompting a change from a one-second to a one-minute granularity for the timestamp tiebreaker. ISO-NE addressed the software issue by moving to a one-minute granularity. If both participants offered bids within the same one-minute period, the bids would be prorated.

Figure 4-6: Examples of Bidding at Highgate



Without a virtual demand bid: there is no counter-flow in the day-ahead market and both 225 MW bids cannot clear at their full volumes, since combined (450 MW) they exceed the TTC (225 MW). In the day-ahead market, these bids get prorated: Company A gets an award of 113 MW, and Company B gets 112 MW.[236] This means that the tie-breaker logic for real-time scheduling binds at Step 2 as there is a slight difference enforced in the day-ahead clearing logic. In the *real-time market*, the 450 MW of total fixed-price bids again cannot both clear. Based on Step 2 binding each company's real-time cleared volumes would remain the same as the day-ahead (112 MW and 113 MW).

With a virtual demand bid: Company A and B submit the same fixed-price import bids, each for 225 MW. In addition, Company A submits a virtual demand bid at a price greater than the LMP, also for 225 MW. This cleared virtual demand provides counter-flow, allowing all 450 MW of import transactions to clear (unlike in the prior scenario). Net imports total 225 MW (the maximum TTC), so no tie-breaker is needed in the day-ahead market. Continuing with this scenario, in the real-time market, both Company A and Company B submit fixed-price import transactions 225 MW each. Therefore, both import offers cannot clear as it would violate the TTC. The clearing logic moves down the priority ranking to the timestamp of the import offer (Step 3) since day-ahead cleared import volumes are the same. Now, let's assume a participant would only do this if had submitted its import offer before Company B, 40 days prior. If so, Company A secures the full 225 MW of real-time scheduled flows.

The timestamp tiebreaker incentivizes participants to submit external transactions as early as possible. Removing the time-of-submission tiebreaker could 1) reduce the incentive to clear virtual demand with the intention of gaining clearing priority and 2) reduce barriers for participants to adjust offers before the clearing of the day-ahead market.

If the timestamp tiebreaker was removed, the virtual demand bid in Figure 4-6 would no longer help Company A gain real-time scheduling priority. If Company A cleared a virtual demand bid,

[236] ISO-NE does not award partial MWs in the clearing of external transactions. The earliest submitted bid receives the additional MW.

the imports would be prorated (Step 4) as the time of submission (Step 3) would no longer impact clearing. The participant's real-time schedules would be the same as in the example without a virtual demand bid (113 MW and 112 MW). However, participants could clear quantities of virtual and external transactions in excess of the TTC in the day-ahead market. When clearing transactions in the real-time market, the higher day-ahead award and real-time offer would allow the importer to gain a greater share of prorated real-time schedules.[237] Even though virtual demand could still be used to influence real-time scheduling, uplift and transaction costs would increase with the higher cleared day-ahead volumes.

Currently, the timestamp tiebreaker incentivizes participants to leave their offers unmodified after submission. If participants want to update their offer, they could lose priority as the timestamp of the transaction is updated when it is reoffered. Removing the timestamp would allow participants to update transactions closer to the operating day as weather conditions and energy prices become more predictable. For example, a participant importing renewable energy into New England may be incentivized to submit their import offer 40 days in advance to obtain an early timestamp. As the operating day approaches, weather forecasting would become more accurate, and a participant may want to update their offer in line with the more up-to-date forecast. The timestamp tiebreaker can be a barrier to updating external transactions, and could prevent participants from updating offer prices as their costs and system conditions become easier to forecast closer to the operating day.

We recommend that ISO-NE re-evaluates non-CTS external interface clearing rules to ensure participants are incentivized to offer external transactions that reflect expected quantities at the cost or value of the underlying energy. Despite the recent modification to the timestamp tiebreaker granularity, the mechanics of the non-NYN interfaces, including the tiebreaking logic, result in undesirable incentives. With 67% of net imports coming from non-NYN interfaces over the last five years, the ISO should take necessary steps to ensure economically efficient short and long-term incentives.

4.2 Coordinated Transaction Scheduling

This section provides an update on the assessment of how coordinated transaction scheduling (CTS) is functioning. Specifically, we review CTS performance metrics against its high-level performance indicators, including scheduling efficiency, price convergence, and price forecast error. We continue to recommend the ISO assess enhancements to price forecasting to minimize forecast error, or changes to CTS mechanics to minimize the impact of price forecast error.[238]

[237] A participant could clear 450 MW of imports and virtual demand at the interface. If a second participant still cleared 225 MW, prorated values would be 150 MW and 75 MW.

[238] A summary of this and other recommendations can be found in the executive summary of this report. For a more in-depth analysis of CTS outcomes, see our *2022 Annual Markets Report* (June 5, 2023) available at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

Key Takeaways

CTS produced similar outcomes to previous years. Price forecast error continues to dampen the positive impacts of CTS by creating financial risk for participants at the Roseton interface and is likely impacting bid and offer behavior. Specifically, participants often clear day-ahead transactions then offer hedged price-insensitive transactions in the real-time market. Lower price-sensitive offered capacity in real-time reduces the ability of the CTS engine to adjust flows as New England and New York price spreads fluctuate.

On average, the CTS engine could have used 232 MW of unutilized capacity per hour to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). The CTS engine was often unable to converge prices due to the unwillingness of participants to adjust to real-time price differences.

We encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy. Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost.

4.2.1 CTS Performance

We assess CTS performance against two measures of efficiency: the flow of power from the lower-to higher-cost region and degree of price convergence between New England and New York.

A summary of CTS power flows between the two control areas is shown in Table 4-3 below. The percentage of time power flowed into New England is shown in the *Net Flow* column.[239] The percentage of time the flow was directionally correct (i.e., power flowed from lower- to high-cost region, based on actual prices) is shown in the *Correct Flow* column.[240] The average New England price premium is shown for context, as a primary driver of flow direction. The correct flow and average price spreads including potential revenues from the Renewable Energy Certificate (REC) price spread (the difference between the New England and New York REC prices) are also shown to highlight other incentives participants are presented when flowing power across the NYN interface.[241] REC prices are included because 81% of scheduled CTS imported energy and 26% of scheduled CTS exported energy is associated with NEPOOL GIS IDs.[242] GIS IDs track transactions that move power from renewable resources. Although only a

[239] Fixed wheeling transactions at the New York North (NYN) interface are ignored in the analyses contained in this section. These transactions are not cleared in the CTS process. On average, in 2024 there were 40MW of fixed-wheeling transactions net importing over the NYN interface in each interval.

[240] The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface. The NYISO pricing node is "N.E._GEN_SANDY PD" (Sandy Pond) and the ISO-NE node is ".I.ROSETON 345 1" (Roseton). Congestion pricing is removed from external prices to ensure we are better-capturing the marginal cost of energy in each control area at the border. When the ramp or flow limit binds, the prices at the interface reflect the bids and offers that set price based on the forecast, and not necessarily the marginal cost of energy in each control area.

[241] Renewable Energy Certificate prices used in this analysis are the vintage prices from the date of flow. For example, for a transaction flowing on 2/10/2022, the vintage 2022 MA Class 1 REC price and 2022 New York Tier I REC price during the week of 2/5/2022-2/11/2022 is used to reflect the expected value of the RECs at the time of scheduling. In cases where the date falls before the first populated price (e.g., no 2020 NY Tier I REC price data was available before 1/2/2021) the first available price is applied in the analysis.

[242] For more information, see the *NEPOOL Generation Information Session* page, available at https://nepoolgis.com/

portion of imported or exported energy associated with GIS IDs will be eligible for RECs, GIS data is the best data source for identifying potential clean energy transactions available to the IMM.

Table 4-3: Summary of CTS Flows

Year	Net Flow (% of intervals) to ISO-NE	Correct Flow (% of intervals)	Correct Flow (% of intervals, accounting for REC spread)	Average New England Price Premium ($/MWh, without CTS Congestion)	Average New England Price Premium including REC spread ($/MWh, without CTS Congestion)	Average New England Price Premium ($/MWh, with CTS Congestion)[243]
2020	95%	55%	95%	$1.99	$20.92	($0.67)
2021	69%	56%	78%	$1.96	$20.03	($1.65)
2022	51%	57%	65%	($2.92)	$9.47	($4.09)
2023	68%	55%	70%	$2.04	$11.23	($0.91)
2024	81%	54%	68%	$2.15	$10.63	($1.03)

In 2024, power flowed into New England from New York 81% of the time.[244] Despite the alignment of net flow and the average price premium, CTS scheduled flows in the correct direction only 54% of the time on a 15-minute basis (i.e., from lower- to higher-cost region, based on the price without CTS congestion)—similar to the prior four years. When REC prices are included in the price spread, about 70% of the time power flowed in the correct direction.

Table 4-4, below, shows a summary of price convergence between New York and New England and CTS price forecast error.

Table 4-4: Summary of Price Convergence and Forecast Error

Year	NY LBMP ($/MWh)	NE LMP ($/MWh)	Average Absolute Price Spread ($/MWh)	Average Absolute Price Spread as % of ISO-NE LMP (%)	Average Absolute Price Spread Forecast Error ($/MWh)	Average Absolute Price Spread Forecast Error as % of ISO-NE LMP (%)
2020	$20.46	$22.45	$6.87	31%	$6.34	28%
2021	$41.07	$43.03	$12.76	30%	$10.78	25%
2022	$85.78	$82.86	$24.50	30%	$23.31	28%
2023	$32.63	$34.67	$11.98	35%	$10.10	29%
2024	$36.01	$38.15	$10.69	28%	$9.72	25%

[243] The average New England price premium is shown in this table to highlight that although New England prices exceed New York prices (based on the "Average New England Price Premium without CTS Congestion" columns), participants are unable to capture that price spread due to the number of negatively-priced import offers. These negatively-priced import offers often set price, leading to a New York price premium once congestion, caused by these negatively-priced imports, is factored in.

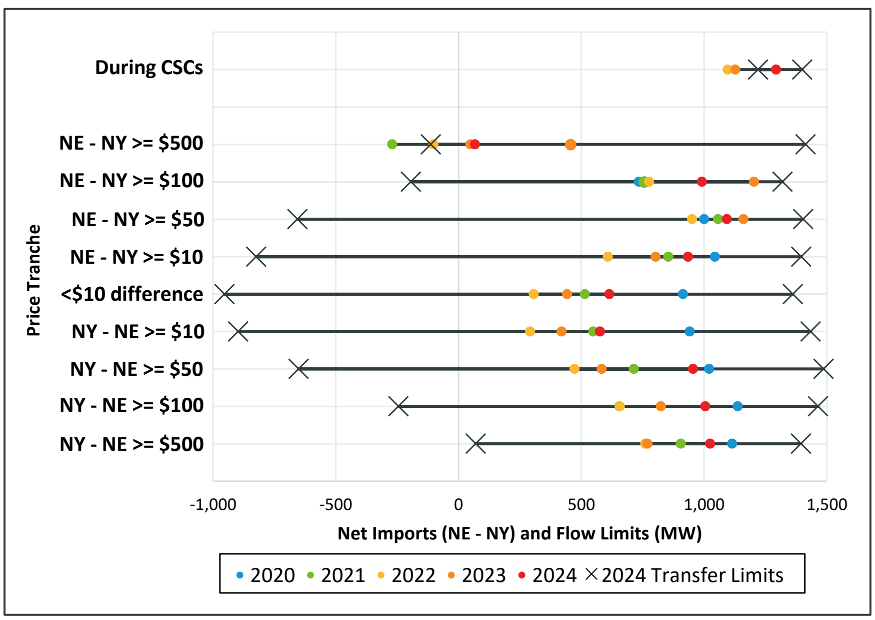
[244] These prices do not reflect CTS congestion to better capture the marginal cost of energy in each control area, rather than the prices of the CTS transactions that set price when an interface constraint is binding.

Although the absolute price spread in 2024 was similar to the price spread in 2023, the absolute price difference between New York and New England was 28% of the LMP, slightly lower than in previous years. This could indicate that the CTS engine helped converge prices more efficiently than in previous years, or that there are other regional dynamics that are leading to marginally-better price convergence between regions.

Many variables impact the price spread between New York and New England (e.g., generator and transmission outages, interconnections with other areas, differences in scarcity pricing rules) so the price spread cannot be fully attributed to the efficiency of CTS solutions. However, CTS solutions did not efficiently utilize the New York North interface capacity to converge prices. On average, the CTS engine could have used 232 MW of unutilized capacity to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint).

Figure 4-7 below, shows the average net flow of external transactions over the New York North interface, by price spread tranche. Additionally, the net flow of external transactions during capacity scarcity conditions (CSCs) is also shown in the line at the top. The × symbols on the line mark the 2024 import and export limits in the intervals shown. The red dots in show the average scheduled net interchange in 2024.

Figure 4-7: Average NYN Flow by NE-NY Price Spread



During the two CSC events in 2024, New England scheduled about 1,300 MW of imports over the NYN interface. This flow was primarily driven by the export-flow limit, which constrained the CTS solution to between 1,220 MW and 1,400 MW of net imports. The lowest average net interchange in 2024 within any tranche was, unintuitively, in intervals where the New England LMP was over $500/MWh higher than the New York LBMP (excluding CTS-driven congestion). In 13 out of 22 intervals in 2024 where the NE LMP exceeded the NY LBMP the CTS forecast predicted the NY price would be higher than the NE price. In intervals in which New York prices exceeded New England prices by over $500/MWh, New England imported (unintuitively) over 1,000 MW on average. In 13 out of 22 intervals in 2024 the CTS forecast predicted a New England price premium, despite a realized New York price premium exceeding $500/MWh.

The CTS engine did not converge prices efficiently, by utilizing the available capacity to converge prices, due to the unwillingness of participants to adjust to real-time price differences, which in turn is likely influenced by the risks they bear due to price-forecast error.

In 2024, 55% of cleared CTS transactions were offered at less than -$50/MWh. These price-insensitive CTS transactions were typically not exposed to real-time prices—87% of offered CTS transactions priced at less than -$50/MWh were backed by a day-ahead transaction. This strategy is likely a product of price-forecast error risk borne by CTS participants. The average absolute price spread forecast error was $9.72/MWh (25% of the New England LMP) in 2024.

Section 5
Virtual Transactions

This section covers our assessment of virtual transaction participation in the day-ahead energy market, including the level of activity, or competition added to the day-ahead energy market. We cover the trends and drivers of participation, and the value added to market efficiency. Finally, we present and discuss the results of profitability metrics at both a system and location level.

Key Takeaways

Virtual Transaction Volumes and Drivers: Average cleared virtual supply (860 MW per hour) increased mainly due to growing energy output from settlement-only solar generators (SOGs). Virtual supply was notably higher during the daytime hours than other times of the day, reaching as high as 1,555 MW per hour, on average, during HE 13. We have observed a clear relationship between virtual supply and solar generation, particularly on high solar output days. Most solar generation in the ISO-NE market registers as SOG and since they cannot participate in the day-ahead market, virtual participants anticipate the additional real-time generation and clear virtual supply in the day-ahead market in their place. These virtual supply offers effectively replace the price-taking SOGs that show up in real time and help improve price convergence during the middle of the day. Virtual supply also performs a similar function with respect to wholesale market participating renewable generation (non-SOG wind and solar) which tend to clear less in the day-ahead market compared to actual real-time production.

Average cleared virtual demand (401 MW per hour) decreased at all different location types. External interfaces saw the largest decrease in cleared virtual demand, mostly due to decreased clearing at the Highgate interface. The reduction in virtual demand was in line with the reduction in imports at the interface.

Price Convergence: This price-converging function of virtual transactions is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market.

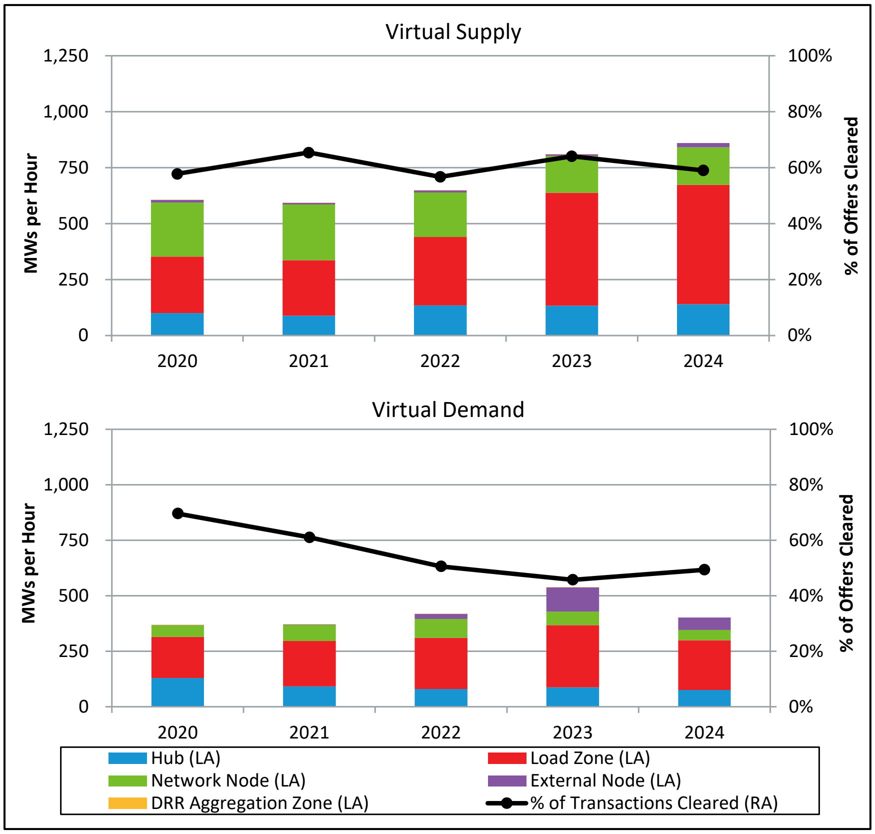
Uplift Charge Allocation: We continue to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and don't pose an inefficient participation obstacle given the important role that virtual supply plays in lowering day-ahead prices. The allocation of uplift and uncertainty regarding the charge impacts virtual supply offers and the day-ahead LMP which drives the vast majority of consumer costs.

NCPC credits increased due to virtual supply relieving congestion at external interfaces. These external credits led to a lower than normal NCPC charges for virtual supply. In 2024, average NCPC charges for virtual demand remained similar to levels in 2023. After accounting for NCPC charges, virtual supply transactions remained profitable ($1.86/MWh) while virtual demand transactions incurred the largest losses over the five-year period (-$3.37/MWh). Total NCPC charges averaged $0.47/MWh

Virtual Transaction Volume

Participants submit virtual demand bids and virtual supply offers to profit from, or limit exposure to, differences in the day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model to better reflect real-time conditions. The average volumes of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 5-1 below.[245]

Figure 5-1: Cleared Virtual Transaction Volumes by Location Type and Bid Type



Cleared virtual supply continues to increase due to the growing amount of solar settlement-only generators (SOGs). Currently, SOGs cannot clear in the day-ahead market, but provide energy in real-time market. On days with high solar generation, high volumes of virtual supply clear in the day-ahead market to help fill this gap. The high levels of virtual supply prevent the day-ahead market from over-committing generation and better align day-ahead and real-time prices.

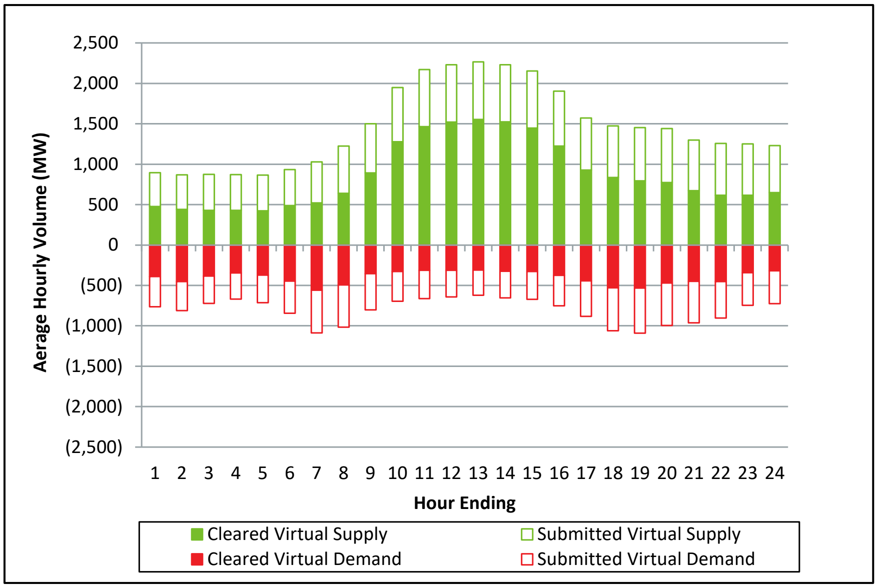
Another reason for growing virtual supply is the day-ahead bidding behavior of wind and solar do-not-exceed (DNE) dispatch generators. Typically, these generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market. Since these generators are frequently in export-constrained areas, virtual supply can profit from day-ahead and real-time price differences.

[245] Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Cleared virtual demand fell in 2024, partially due to less clearing at the external interfaces. Virtual activity at external interfaces has historically been small compared to other location types. In 2023, higher volumes of virtual demand cleared at the Highgate interface (74 MW per hour) compared to 2024 (30 MW per hour)

Higher levels of virtual supply tended to be submitted and cleared during the middle part of the day, while higher levels of demand tended to be submitted and cleared during the morning and evening ramp periods. This can be seen in Figure 5-2 which shows the average hourly volume of submitted and cleared virtual transactions by time of day in 2024. Virtual supply is depicted as positive values, while virtual demand is depicted as negative values.

Figure 5-2: Average Hourly Submitted and Cleared Virtual Transaction Volumes by Time of Day, 2024



More virtual supply clears during the middle of the operating day than in the morning or evenings. Between hours ending 9 through 17, cleared virtual supply averaged about 1,315 MW per hour compared to 587 MW per hour during the rest of the day. We have observed a clear relationship between virtual supply and solar generation, particularly on high solar output days. Most solar generation in the ISO-NE market registers as SOGs.[246] Since SOGs cannot clear in the day-ahead market, virtual participants anticipate the additional real-time generation and clear virtual supply in the day-ahead market in their place.[247] These virtual supply offers effectively replace the price-taking SOGs that show up in real time.

Meanwhile, the average volume of cleared virtual demand continues to be slightly higher during the morning and evening ramping periods, when loads are higher and prices tend to be more volatile in the real-time market.

[246] By the end of 2024, settlement-only photovoltaic generators had an installed capacity of about 2,360 MWs.

[247] The differences in the supply mix between the day-ahead and real-time energy markets are examined in Section 3.2.4.

Virtual Transaction Profitability

Virtual transactions profit from differences between day-ahead and real-time prices. However, transaction costs in the form of NCPC charges can turn otherwise profitable virtual transactions into unprofitable transactions on a net basis.[248] This limits the ability of virtual transactions to converge prices between day-ahead and real-time market, which is one of their intended market functions.[249]

This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation.[250]

Figure 5-3 illustrates the profitability of virtual transactions along with the impact of NCPC charges on profitability. This figure displays the average annual gross and net profit of virtual transactions since 2020 (left axis).[251]

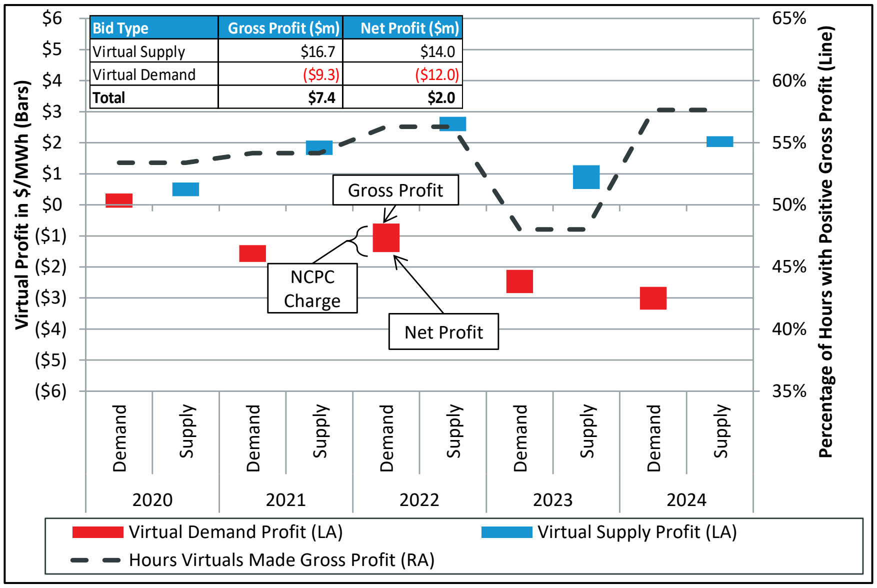
[248] The ISO allocates the following NCPC charges to cleared virtual transactions: (1) **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) incur a charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations; and (2) **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because total day-ahead economic NCPC is divided among a much larger quantity of energy.
Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report.

[249] The role of virtual transactions in price convergence is discussed in more detail in Section 3.1.4.

[250] For more information on recommended market design changes, see the table in the Executive Summary.

[251] The bars are categorized by year and bid type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MWh NCPC charge. The inset table shows profitability by bid type for 2024. Additionally, the dashed black line shows the percentage of hours each year in which virtual transactions were profitable on a gross basis (right axis). The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

Figure 5-3: Average Annual Gross and Net Profits for Virtual Transactions



Virtual supply made a gross profit of $16.7 million, or $2.21/MWh, in 2024. While virtual supply profitability increased from 2023 ($1.28/MWh), profitability was more in line with prior years. Virtual supply continued to make higher profits during the middle of the operating day, when day-ahead prices were typically higher than real-time prices. Between hours ending (HE) 9 and 17, participants made a total net profit of over $11.8 million in 2024, which accounted for 71% of the virtual supply's net profit ($14.0 million) during the year.

The relationship between virtual supply and settlement-only solar generation helped drive these higher profits during the middle of the day. Participants cleared more virtual supply in 2024 during HE 9 to 17, averaging 1,315 MW, which was a 100 MW increase from 2023. This increase was in line with the increase in solar settlement-only generation (90 MW) during the middle of the day.

Virtual demand, incurred a gross loss of -$2.64/MWh on average in 2024, the highest gross loss for virtual demand over the last five years. Virtual demand has typically lost money on an annual basis as real-time prices tend to be lower than day-ahead prices, on average. Additionally, participants continued to clear higher volumes of virtual demand at external nodes in 2024. These bids tend to be related to scheduling priority for import transactions rather than speculative bids aiming to profit on day-ahead and real-time price differences.[252]

Average NCPC charges for virtual transactions decreased for virtual supply due high NCPC credits paid to virtual transactions relieving congestion, especially at the New Brunswick interface (discussed below).[253] In 2024, virtual supply remained profitable after the netting of NCPC charges, making a net profit of $1.86/MWh, on average. For virtual demand, average

[252] For example, a participant with a large portfolio of generation assets may use virtual demand to hedge against higher real-time prices that might occur if one of their assets goes out of service in the real-time market after clearing in the day-ahead market.

[253] For more information on NCPC credits at external interfaces, see 4.1.3.

NCPC charges remained similar to the prior year. Virtual demand lost $3.37/MWh, on average, after accounting for NCPC charges. For both bid types, NCPC charges averaged $0.47/MWh.

Most Profitable Locations for Virtual Supply

Details of the top 10 most profitable locations for virtual supply in 2024, after accounting for transaction costs and NCPC charges/credits (ranked by total net profit), are shown in Table 5-1 below.[254]

Table 5-1: Top 10 Most Profitable Locations for Virtual Supply, 2024

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.I.SALBRYNB345 1	Ext. Interface	985,979	129,329	$552	$2,400	$4.27	$18.56	14
.Z.MAINE	Load Zone	884,383	655,899	$1,804	$1,390	$2.75	$2.12	20
.Z.VERMONT	Load Zone	532,798	396,570	$1,504	$1,219	$3.79	$3.08	18
.H.INTERNAL_HUB	Hub	1,689,160	1,228,823	$1,870	$1,055	$1.52	$0.86	37
.Z.SEMASS	Load Zone	880,865	698,765	$1,278	$819	$1.83	$1.17	19
.Z.NEMASSBOST	Load Zone	1,115,856	933,502	$1,381	$764	$1.48	$0.82	17
UN.BINGHAM 34.5BNGW	Gen Node	172,100	111,466	$770	$705	$6.91	$6.33	17
.Z.RHODEISLAND	Load Zone	487,332	385,207	$905	$658	$2.35	$1.71	15
.Z.NEWHAMPSHIRE	Load Zone	1,015,650	855,600	$1,167	$598	$1.36	$0.70	16
.Z.WCMASS	Load Zone	437,370	377,700	$738	$488	$1.95	$1.29	17

The most profitable location for virtual supply was .I.SALBRYNB345 1, the external proxy node for the New Brunswick interface. Historically, New England has been a net importer of energy over this interface, but an extended nuclear outage in New Brunswick led to New England exporting to New Brunswick from April to December, on average. The interface was frequently export-constrained with high-priced or fixed export bids in excess of the Total Transfer Capability (TTC) of the interface. Since congestion is unpriced at most external interfaces, counter-flow bids (i.e., virtual supply or imports) priced above the LMP, but lower than the export bids can still clear. This results in uplift payments from exporters to the counter-flow transactions. Virtual supply received high uplift payments for relieving day-ahead congestion at the interface.

Eight of the top ten locations consisted of the Hub and seven of the eight load zones. High total net profits at these locations were in line with the lower real-time prices at these locations, especially during the middle of the operating day.

The last location is associated with wind power generation. Certain wind generators are part of the set of resources known as do-not-exceed (DNE) dispatchable generators (DDGs). Wind generators often clear lower volumes in the day-ahead market but produce more real-time output at low or even negative real-time prices. Virtual supply participants fill this gap by

[254] For more information about the additional charges for virtual transactions, see *Section IV.A Recovery of ISO Administrative Expenses*, Schedule 2 Energy Administration Service, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf

clearing virtual supply at prices more in line with real-time expectations, particularly on windy days.[255]

Most Profitable Locations for Virtual Demand

Details for the 10 most profitable locations for virtual demand in 2024, after accounting for transaction charges and all relevant NCPC charges/credits (ranked by total net profit), are shown in Table 5-2 below.

Table 5-2: Top 10 Most Profitable Locations for Virtual Demand, 2024

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.JAY_VT 46 KCW	Gen Node	55,501	11,783	$113	$105	$9.59	$8.87	14
LD.MAYNARD 13.8110B LD	Load Node	464	464	$52	$52	$113.27	$111.26	1
LD.ORCHARD 13.8	Load Node	558	558	$51	$50	$91.47	$89.40	1
LD.SPEEN_ST13.8	Gen Node	2,048	1,267	$49	$48	$38.93	$38.03	3
UN.OCEAN_ST13.8OSP1	Gen Node	822	822	$48	$47	$58.87	$57.30	1
LD.HALVARSN345 SMDINTLD	Load Node	5,165	4,252	$50	$46	$11.85	$10.71	3
LD.MADISON 115	Gen Node	181	181	$31	$30	$168.45	$167.14	1
LD.SHUNOCK 13.8	Load Node	2,699	2,699	$16	$13	$5.89	$4.82	1
LD.HARRIS 13.2	Load Node	1,881	1,761	$13	$11	$7.47	$6.45	3
LD.MT_SUPP 13.8	Gen Node	2,055	1,158	$11	$10	$9.30	$8.97	2

The 10 most profitable locations consisted of generator and load nodes that saw little virtual demand trading activity throughout the year. UN.JAY_VT 46 KCW was the only location to have more than 1 MWh of virtual demand clearing on average.

[255] These locations tend to be riskier as well, given the difficulty of forecasting wind generation. For example, if a participant expects high wind output in the real-time market, they might clear virtual supply in the day-ahead market at a low price, and expect to profit off negative real-time prices. However, if the wind generation does not meet day-ahead expectations, these locations will likely be unconstrained, and the participant would have to pay its day-ahead obligation back at a higher real-time price.

Section 6
Forward Capacity Market

Forward Capacity Auction 19 (for 2028/29 delivery) was delayed until 2028 as the forward capacity market shifts to a prompt auction structure as part of the Capacity Auction Reforms (CAR) project.[256] In this section, we first discuss and provide our current thinking and recommendations on aspects of the CAR design specific to the deactivation (retirement process) and mitigation. The second section includes a number of issues and recommendations on other aspects of the capacity market.

Finally, since no forward capacity auction occurred in 2024, we focus on secondary market activity and Pay for Performance (PfP) settlement outcomes. Monthly reconfiguration auctions for Capacity Commitment Periods (CCP) 14-15 and annual reconfiguration auctions for CCP 16 and CCP 17 were held during the year. Section 6.3 summarizes the outcomes of these reconfiguration auctions. Section 6.4 covers the PfP events on June 18 and August 1, 2024, which mark an increase in reserve deficiency hours and total PfP payments relative to 2023.

6.1 Capacity Auction Reforms

The Capacity Auction Reform (CAR) project is a multi-year initiative aimed at overhauling key aspects of the capacity market, including auction timing, seasonal procurement, and capacity qualification and exit (deactivation) rules. These changes are critical to improving the cost-effectiveness of how the market procures and prices capacity to meet its resource adequacy goals. By moving away from the current structure—where capacity is procured more than three years in advance—the revised design better aligns the market with the varying and uncertain timelines for new resource development, decision timing on resource exit, the unpredictable pace of peak load growth, and reliability risk profile that varies by season.[257]

6.1.1 Coordination of Entry, Exit and Reentry

A core function of wholesale electricity markets is to facilitate the efficient entry and exit of resources through price signals that align with system reliability needs—across energy, capacity, and ancillary service requirements. Markets operate most cost-effectively when barriers to entry and exit are low, allowing resources to respond to changing conditions. This flexibility becomes especially important amid uncertainty in demand and supply fundamentals. For example, the cost of responding to an unexpected supply shortfall or higher-than-forecast demand—both of which impact system reliability—may largely depend on how quickly and efficiently resources can be brought online or redeployed.

In New England, there is uncertainty surrounding the pace and scale of demand growth, which will primarily be driven by the electrification of transportation and heating. While data center load is not currently expected to be a major contributor, it could become more significant over the longer term. On the supply side, challenges persist with permitting, supply chain

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[256] For more details on the CAR project, see the ISO's *Capacity Auction Reforms Key Project* page, available at https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[257] See the IMM's memo to the NEPOOL Markets Committee, *IMM Thoughts on A Prompt and Seasonal Capacity Market* (January 31, 2024), available at ttps://www.iso-ne.com/static-assets/documents/100009/a02b_mc_2024_03_12_13_imm_perspective_alternative_fcm_commitment_horizons.pdf

constraints, and timing of policy-driven procurements. Although merchant supply development is incentivized by wholesale market price signals, the timing of policy resource entry is largely driven by state government decarbonization targets—potentially impacting market price signals.

Given these medium- to longer-term dynamics, we believe it is prudent for the CAR design to incorporate flexibility around the exit and potential re-entry of existing resources. Near term, the market is long on capacity relative to the 1-in-10 capacity requirement (Net Installed Capacity Requirement) with much lower capacity prices than the Net Cost of New Entry (Net CONE) benchmark. As a result, many existing resources—facing low capacity prices and limited utilization in the energy and ancillary services markets—are reaching the end of their economic life and are expected to retire. This will tighten the supply-demand balance over time. Depending on the pace and cost of new resource development, it may prove more cost-effective for the market to procure existing resources that can be reactivated, rather than relying solely on new entry.

Repowering Threshold

Currently, there is a high administratively set capital investment threshold for retired resources to re-enter the capacity market (known as the repowering rules), set at $417/kW (e.g., $208.5 million for a 500 MW generator). While this threshold may have been in place to limit the ability to toggle between existing and new capacity qualification rules and therefore benefit from multi-year rate-lock, it has outlived its purpose. First, the multi-year rate lock has expired for new capacity resources, and under a prompt market construct, all resources will essentially be existing at the time of the auction.

Second, this provision creates an unnecessary barrier to exit and re-entry. In other words, the re-entry fee is prohibitively high that it can impact the economics of the exit decision, and then directly impact the cost of re-entry. Eliminating this threshold potentially adds to the overall amount of supply competing to meet the region's capacity requirement, and in turn helps to achieve a more cost-effective selection of resources. [258]

Revocability of Deactivation Notifications

An important consideration under the CAR design is the timing and revocability of deactivation notifications. The design seeks to balance a number of tradeoffs. Under the current ISO proposal, resource owners must submit deactivation notices two years prior to the relevant Capacity Commitment Period (CCP). Once submitted, these notices would generally be irrevocable, except in cases where the resource is determined to be needed for local transmission security, in which case it may be retained under a time-limited cost-of-service agreement. While this approach provides a level of market certainty and signaling, it may limit market flexibility and hinder the efficient coordination of resource exit and re-entry as system and market conditions change.

We believe there is merit in allowing for the cancellation of deactivation notifications, recognizing that a resource's economic outlook may change during the notification period. This

[258] The IMM expressed support for the elimination of the repowering threshold during the Retirement Reform initiative in 2023. See *Initial Comments of the IMM Regarding the Return to Service Proposal* (September 6, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/09/a06_mc_2023_09_12_13_imm_comments_return_to_service_proposal.pdf

revocation window should end sufficiently in advance of the existing capacity qualification deadline for the CCP, but should be sufficiently long to provide economic benefits.

However, introducing this flexibility requires careful rule design to preserve the integrity of the power system and market power study processes (e.g., deter information or RMR fishing), and to promote the efficient release of scarce transmission capacity for potential new entrants. One potential safeguard could be a requirement that the participant demonstrate to the satisfaction of the ISO or its IMM that the resource's economic conditions have materially improved before it is permitted to reverse its retirement plans.[259] The burden should be on the participant to demonstrate a substantial change in circumstances to warrant an exception from its prior deactivation notification. Importantly, we do not believe it is appropriate for a resource to withdraw a deactivation notice solely in response to a market power mitigation determination by the IMM, as doing so would erode the deterrent effect of the mitigation framework.

Additionally, the rules may need to consider scenarios in which remedial transmission upgrades were initiated in response to a deactivation notice. In such cases, it may be appropriate under the cost-causation principle to assign associated transmission costs to the resource if it subsequently re-enters the market.

6.1.2 Price Formation and the Role of Mitigation and Recommendation to Adopt a Conduct and Impact Framework

In our January 2024 memo to the NEPOOL Markets Committee, the IMM discussed, *inter alia*, the important attributes and principles of a market power mitigation framework in helping to facilitate price formation.[260] When market power is present, the mitigation rules should help ensure that offer prices reflect levels that would otherwise be expected in a competitive market and therefore should positively impact price formation and market confidence for both producers and consumers. In other words, the mitigation rules must be consistent with the incentives underpinning competitive offer formulation in a prompt and seasonal capacity market construct.

The market power rules should also minimize interference with open and competitive markets and allow prices to be set by competitive forces to the maximum extent practicable. Therefore, the rules and screening thresholds should be proportionate to the ability and incentives of participants to exercise market power.

The CAR initiative requires a review of the current mitigation rules to ensure consistency with a prompt and seasonal market, and with new accreditation rules. It also provides an opportunity to ensure that the rules are aligned with the above principles. In this regard there are improvements that can be made to the seller-side mitigation rules that apply to existing resources submitting capacity offers for a single delivery period. Specifically, we recommend that the ISO introduce a Conduct and Impact (C&I) test framework to replace the current Pivotal

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[259] This exit path from a retirement track is not a new concept. Section III.13.1.2.3.2.1 of the ISO-NE Tariff allows resources to exit the retirement track by providing updated information and requesting to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction. The update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.
[260] See subsection “The Role of Market Power Mitigation in Price Formation” *supra note 257*.

Supplier Test (PST). There are number of potential benefits to introducing a C&I framework, including:

- a more accurate assessment of market power;
- a consistent mitigation framework;
- a C&I approach could reduce the influence of the conduct review threshold value (currently known as the Dynamic Delist Bid Threshold or DDBT); and
- a C&I approach could conceptually incorporate buyer-side mitigation rules

A More Accurate Assessment of Market Power

The current seller-side market power framework for single year offer (also known as static delist bids) relies on a Structural Test (the PST) and a Conduct Test. If a resource fails both tests, it is mitigated to an IMM price, which is the IMM's competitive benchmark price for the resource. The IMM price is binding, regardless of whether the participant offer would have impacted the clearing price.

While the PST can be an indicator of the ability and incentive to exercise market power, it does not measure the impact of suppliers' offer behavior (whether pivotal and non-pivotal) on price; nor does not address the potential for strategic and collusive behavior. Yet the proposed change to the auction format, from a descending clock auction to a first-price sealed bid (one-shot) auction, facilitates the assessment of market impact since the complete supply curve is available at one instant in time.

The Impact Test directly measures the combined impact of uncompetitive offer behavior on market outcomes: clearing prices and quantities. It is performed through a second auction clearing by substituting supply offers with IMM Prices for any resource that failed a Conduct Test. This is consistent with the price impact assessment in the energy market.

The region is likely to continue to be long on capacity when the next auction takes place for the commitment period starting in June 2028. It is therefore likely that mitigation will not apply to existing capacity resources based on the PST. Indeed, over the past five capacity auctions (FCAs 14-18) the system has been long on capacity and there have been no pivotal suppliers. At the system-wide level for FCA 18, a company needed a portfolio of about 3,300 MW to be a pivotal supplier.[261]

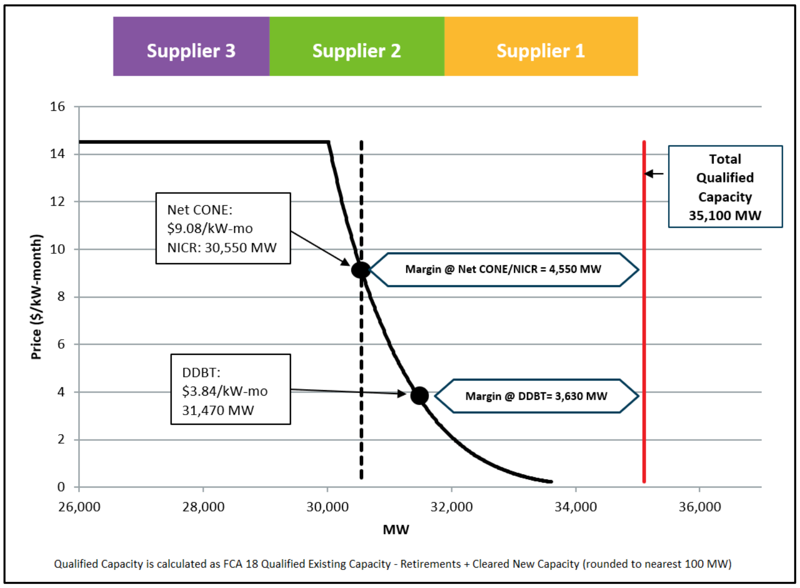
Figure 6-1 below provides an overview of the demand and supply landscape based on publicly available data from FCA 18. Within the context of the FCA 18 demand curve and auction parameters—such as Net CONE, NICR, and the DDBT—the total qualified capacity is shown to illustrate supply margins, a key input to the PST. Qualified capacity includes both new capacity cleared in FCA 18 and existing qualified capacity for FCA 18 net of retirements.[262] The top portion of the graph shows the three largest suppliers to approximate scale with the bottom graph. For example, without Supplier 1's entire portfolio there is still ~32,000 MW of remaining

[261] See our *2023 Annual Markets Report* (May 24, 2024), Section 2.3, available at https://www.iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf

[262] It should be noted that the resource capacity accreditation will also impact qualified supply and system demand, but at this time it impact on the PST is unknown.

capacity; without Supplier 1 and 2, remaining capacity falls short of NICR to under 30,000 MW etc.

Figure 6-1: Qualified Capacity, Demand and Three Largest Suppliers



Based on the current formulation of the PST, a supplier would need capacity of 4,550 MW to be considered pivotal and be subject to mitigation.[263] If the PST were to be performed at the quantity associated with the DDBT the portfolio size would need to be 3,630 MW. Further, if a PST were to be performed for the three largest suppliers (as is done in PJM) all suppliers in the market would be pivotal.

However, we are not recommending changes to the PST, but rather that it be replaced with an Impact Test. While the market is currently long on capacity and the ability to unilaterally exercise market power is low, adopting an Impact Test is robust under all supply/demand conditions. As the supply/demand balance tightens, the use of the PST could result in the over-mitigation of resources.

A Consistent Mitigation Framework

The three forms of mitigation in the capacity market are captured in the table below.

Table 6-1: Overview of Capacity Market Mitigation Rules

		Tests in Market Power Mitigation Process		
Supply Type	**Category**	**Size threshold**	**Conduct**	**Impact**
New Supply Entry	Buyer-side	5 MW	Yes	Yes*
Deactivation	Seller-side	20 MW	Yes	Yes**
Existing supply	Seller-side	Pivotal Supplier	Yes	No

* The impact assessment can be included in the form of an Incentive Rebuttal option that a seller can submit

** it is proposed that the impact of the deactivation be assessed through a portfolio benefits test

[263] However, any offer above the conduct review threshold would still be subject to an IMM cost review.

Seller-side mitigation (existing supply) is the only form of mitigation that does not include some form of impact test or an impact assessment. Under current market conditions a portfolio needs to be very significant in size to be considered pivotal and be subject to mitigation. By contrast, deactivations above 20 MW are subject to a market power assessment.

An Impact Test Approach could Reduce the Perceived Influence of the Conduct Test Review Threshold (Dynamic Delist Bid Threshold)

In the past three auctions, a significant amount of capacity has delisted at prices just below the DDBT. This may indicate that some resources have higher net going forward costs than the DDBT but are willing to risk offering at a lower price (below cost) close to the DDBT to exit. Some stakeholders have raised concerns that the IMM's cost review process may deter participants from seeking review. As a result, there is a concern that the DDBT is exerting an outsized influence on both participant behavior and auction clearing outcomes, which potentially distorts price formation.

In a well-functioning market, it is essential that participants are not discouraged from offering at their true incremental cost. A Conduct and Impact (C&I) framework may better support this objective. Unlike the current approach—where the IMM-determined price is binding for pivotal suppliers—the C&I model shifts the focus to whether a supplier's offer has a material impact on the auction clearing price.

Under this framework, the cost review process would still apply to resources seeking to offer above a defined price threshold. However, suppliers would have greater flexibility in submitting offers that reflect their own estimates of net going-forward costs, even in cases where those estimates differ from the IMM's reference price. The IMM price would function as a benchmark for evaluating market impact in a secondary auction clearing run, with mitigation applied only when the price increase exceeds a predetermined impact threshold.[264]

An Impact Test Approach could Conceptually Incorporate Buyer-side Mitigation Rules

At least at a conceptual level, the opposing impacts of seller- and buyer-side market power could have offsetting impacts on the clearing price and allow existing and new resources to clear offer prices different from IMM prices while still maintaining reasonable price formation.

6.2 Recommended Changes to Various Aspects of the Capacity Market Rules

There are a number of areas where the capacity markets rules can be enhanced that are not directly related to the scope of the aforementioned CAR project, but should nonetheless be considered. Here, we make recommendations in three areas. The first relates to the allocation of capacity charges, specifically Pay-for-Performance (PfP) charges to exports during Capacity Scarcity Conditions (6.2.1). The next two recommendations relate to areas of the rules which generate issues or concerns around market compliance for market participants. We think the

[264] A cost recovery process, similar to that in place for energy market, could be designed such that if a participant can make a filing with FERC for additional cost recovery if its expects, as a result of mitigation, that it cannot recover its incremental costs of taking on a capacity obligation, as a result of mitigation, expects to incur a loss on its capacity obligation, then a process to seek cost recovery through a filing with FERC.

marketplace would benefit from improvements to the Tariff language to enhance clarity. The first relates to compliance with the must-offer obligation for unavailable capacity resources (6.2.2), and the second relates to the time-out provisions for network and capacity interconnection rights (6.2.3).

6.2.1 Recommendation on PfP Treatment of Exports

Following the External Market Monitor's recommendation, we also recommend that ISO-NE update the current Pay-for-Performance (PfP) structure to create equal incentives for delivering energy into New England and exporting energy out of New England during a Capacity Scarcity Condition (CSC).[265] Increased imports, or a reduction in exports, can provide the same reliability benefits and help New England avoid or recover from a reserve deficiency. However, current capacity market rules credit imports at the Pay-for-Performance (PfP) rate, but do not charge exports at the same rate.

During shortage events, participants receive PfP payments for their net imports in excess of their expected contribution. By removing a participant's exports from the calculation, PfP settlements reward importers for the actual flow of energy into the region. While participants can receive PfP payments for net imports during shortage events, participants are not charged the PfP rate for only exporting. For example, an over-performing import resource would receive the energy price reflecting reserve shortage pricing and the PfP rate.[266] A participant exporting during the event would pay just the energy price, also incorporating reserve shortage, but not the PfP rate. While there is still high energy costs for exporters, crediting net imports, while not charging net exports at the PPR leads to the two following issues:

1. Misaligned financial settlements between imports and exports

2. Gaming opportunity for related participants

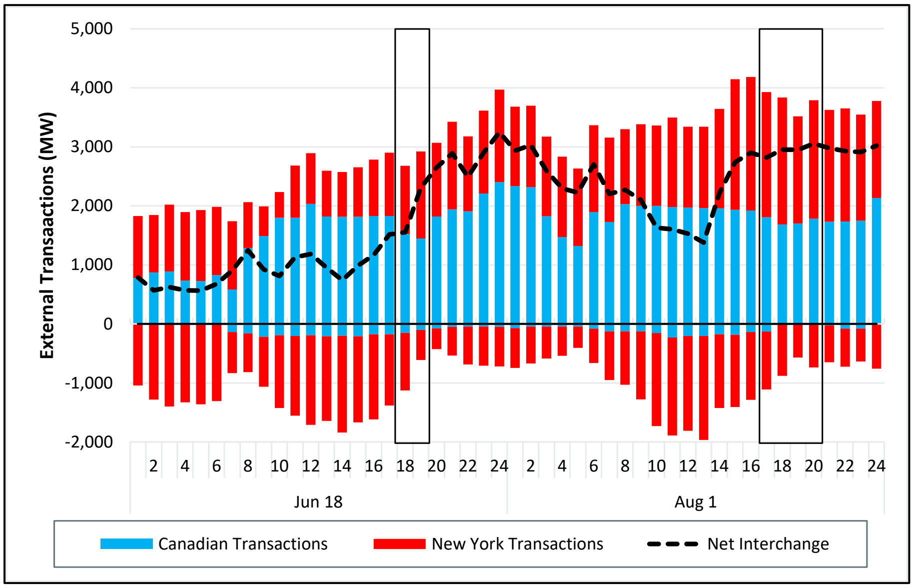
Misaligned Incentives

External transactions can provide critical flexibility during a shortage event. For example, additional imports could push down natural gas-fired generation eligible to meet the reserve requirements, helping the system get out of a reserve deficiency. Similarly, exports could be curtailed by the operators or withdrawn by a participant during scarcity events, providing the same reliability benefits as scheduling more imports.[267] While a reduction in exports provides an identical reliability benefit to procuring more imports, the current rules treat imports as more valuable transactions than exports by applying the PfP rate to a participant's net imports. This misalignment will grow as the PfP rate increases to $9,337/MWh in 2025. Charging exports at the PfP rate would better align the treatment of imports and exports during scarcity events and incentivize exporters to withdraw or reoffer their export transactions.

[265] The External Market Monitor made this same recommendation. Their recommendation can be found in the *2023 ISO New England Assessment of the ISO New England Electricity Markets* (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/07/ISO-NE-2023-EMM-Report_Final.pdf
[266] For simplicity, this example assumes no day-ahead settlement.
[267] For more information on scheduling reductions and curtailments related to capacity deficient conditions, see the ISO's operating procedure *OP-9 Scheduling and Dispatch of External Transactions, Appendix* B, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op9/op9b_rto_final.pdf

Figure 6-2 below shows real-time scheduled external transactions by control area on June 18, 2024, and August 1, 2024, the two days during 2024 with scarcity conditions. The scarcity conditions occurred during the highlighted hourly intervals on these two days.

Figure 6-2: External Transactions by Control Area during Shortage Conditions



While exports tend to be low, Figure 6-2 shows[268] New England still exported nearly 900 MW to neighboring areas during hours ending 18 and 19 on June 18, 2024. During the August 1, 2024 event, New England exported over 800 MW per hour to New York during the four hours with capacity scarcity conditions. No curtailments were made to exports during the August 1, 2024 event.[269] Curtailing exports would have likely reduced the length of both shortage events. Charging exports the PfP rate would further incentivize participants to withdraw export transactions in the real-time market which could reduce the frequency and duration of shortage events.

Gaming Opportunity

A potential gaming opportunity exists during scarcity events since exports are not charged the PfP rate. There is an incentive to import and export during scarcity events since the imports will be paid at the PfP rate, but the exports will not be charged at this rate. While participants are credited for *net imports* at the PfP rate, this rule does not prevent related or colluding entities from exercising this strategy to avoid netting. If one participant imports during the event, they will receive the PfP rate for imports in excess of their expected contribution. If a related entity but a different Market Participant exports, they will only receive charges through the energy market. When coupled, these transactions would have no risk and would always be profitable since the energy market settlements cancel out, but imports receive the PfP rate. While

[269] Imports over the Phase II interface were curtailed to reduce the reserve requirement as the Phase II interface was the largest contingency.

participants could exploit these rules, we have found no evidence of participants exercising this strategy.

Currently, capacity resources receive additional revenues through the PfP rate if they perform better than expected during a scarcity event. However, export transactions receive no additional charges when contributing to scarcity events. The financial incentives for imports and exports should be equivalent as reducing exports can provide the same benefits as scheduling additional imports. Due to the current rules, a potential gaming opportunity exists for related entities. One participant could import energy and receive the PfP rate, while a second participant could export energy without being charged at the PfP rate. Together, these two transactions would always be profitable and provide zero reliability benefits. We recommend that ISO-NE review current capacity market rules to create identical incentives for imports and exports during scarcity events.

6.2.2 Recommendation to Provide Clarity on the Need to Shed a CSO during Outage Periods

To address the potential exercise of market power through physical withholding, the Tariff requires that a non-intermittent generating resource offer its full CSO unless it is only "physically available" at a lesser amount to be offered.[270] However, when a resource is "physically available" could be better described in the Tariff. In addition, the Tariff could specifically address requirements for a capacity resource that is unavailable for an extended period; for example, either to shed its CSO, pay a charge or otherwise compensate for not providing capacity during an extended period in which it continues to receive a CSO payment.

The IMM generally considers a resource to be physically available whenever it is not on a forced or planned outage. This view is internally consistent with other language in the Tariff concerning resource availability, as well as with Commission rulings on the impermissibility of "economic outages" with respect to fuel procurement.

For example, the Tariff defines Equivalent Demand Forced Outage Rate (EFORd) to "mean the portion of time a unit is in demand, but is *unavailable due to forced outages*." Economic maximum limit or economic max is defined as "the maximum *available* output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data."[271]

A capacity resource on outage also must comply with the "outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures." Tariff Section III.13.6.1.1.5(c). Operating Procedure No. 5 ("OP 5") requires that a Market Participant submit an outage request when a planned, maintenance or overrun planned outage "of the resource impacts the CSO of the associated capacity Resource."

Notably, the Tariff does not expressly require a resource on outage to buy out of its CSO in an annual/monthly reconfiguration auction. However, depending on the circumstances, a market

[270] *See* Tariff Sections III.13.6.1.1.1, III.13.6.1.3.1.

[271] See *Order Approving Stipulation and Consent Agreement (EWP Renewable Corp.)*, 189 FERC ¶ 61,233 at P 5 (2024) ("One obligation, set forth in Tariff Section III.13.6.1.1.1(a), is to offer into the ISO-NE energy markets the full amount of cleared capacity, unless the unit declares an outage. *See also New England Power Generators Association v. ISO-New England Inc.*, 144 FERC ¶ 61,157 (2013) (NEPGA I) and *New England Power Generators Association v. ISO-New England Inc.*, 145 FERC ¶ 61,206 (2013) (NEPGA II).

participant may need to buy out of a resource's CSO to satisfy other explicit obligations under the Tariff or be subject to a referral to the Office of Enforcement.[272]

The Commission has approved settlements with participants that did not buy out of their CSOs and continued to receive capacity payments when they in fact had no ability to deliver capacity.[273] Resources may retire early prior to the relevant capacity commitment period if they cover their CSO through a bilateral transfer or reconfiguration auction.[274]

Other situations of "unavailability" run the gamut from:

- retiring resource does not notify the ISO of early retirement and does not shed its obligation but is unable to deliver capacity;
- resources on long-term, medium-term, or short-term outage;
- Active Demand Capacity Resources (ADCR) that fail to obtain sufficient physical capacity (customers) to back a must offer (Tariff Section III.13.6.1.5.1);
- a resource has ambient air temperature limits but takes on a CSO in a reconfiguration auction that is in excess of its maximum output; to
- a resource has no fuel.

Given the wide range and varying degrees of unavailability, the IMM recommends that the Tariff be amended to provide more guidance by quantifying when it is appropriate for a resource on outage to seek to shed its CSO, at a minimum encompassing each of the above scenarios.

For example, last year the Commission approved changes to MISO's Tariff whereby a resource may participate in the capacity market regardless of how many days it is offline. However, if the resource is offline in excess of 31 days in a season it must replace capacity or else pay a fine greater than the cost of acquiring replacement capacity.[275]

The IMM recommends amending the Tariff to better describe physical unavailability and to provide clearer requirements for a (for example, to shed its CSO or pay a charge for not doing so) capacity resource that is physically unavailable for an extended period.

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[272] To qualify and participate in the FCM, a Resource must be physically-backed — i.e., there is no virtual trading/participation of capacity in the FCM unlike in the energy market (see generally Tariff Section III.13.1). A Resource that misrepresents its actual availability in its Supply Offers may be found to violate Tariff requirements and Commission regulations. *See* 18 U.S.C. § 35.41(a)-(b).

[273] EWP Renewable Corp., 189 FERC ¶ 61,233 (2024); Order Approving Stipulation and Consent Agreement (Wheelabrator Claremount Co.), 164 FERC ¶ 61,237 (2018).

[274] Tariff Section III.13.2.5.2.5.3(a)(ii).

[275] For more information on the D.C. Circuit approval, see Appellate Briefs *Entergy Arkansas, LLC, et al. v. FERC,* available at https://www.ferc.gov/enforcement-legal/legal/court-cases/entergy-arkansas-llc-et-al-v-ferc-1

6.2.3 Recommendation to Review and Clarify the Time-out Trigger for Capacity Resource Retirements and Termination of Interconnection Rights

The market rules provide that a resource's interconnection rights (network and capacity) will be terminated and the resource considered retired if it "does not operate commercially" for three calendar years. The rule is consistent with a "use it or lose it" principle that serves the important objective of allowing for the release of transmission capacity that is no longer required by a resource with interconnection rights that could be used by other supply resources. We think that there is benefit to clarifying the language and ensuring its application is consistent with the efficient allocation of transmission capacity among active, viable competitive resources.

Section III.13.2.5.2.5.3.(d), Retirement and Permanent De-Listing of Resources, of the ISO New England Tariff states (emphasis added):

"*A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three-year period will be calculated from the last day of commercial operation of the resource.*"

In particular, the term to "operate commercially", without definition or a specific metric, could result in a resource retaining interconnection rights with no plan to commercially operate in the future, and lead to the inefficient allocation of transmission capacity. As currently implemented, a resource could produce a single kilowatt-hour and thereby reset the three-calendar year clock, and do so on a recurring basis. Therefore, we recommend that the Tariff language be reviewed and clarified such that a resource produces meaningful energy output that's demonstrate its commercial operability. Insignificant or non-substantial megawatt production should not constitute "commercial operation" when applying this rule and could allow for an efficient allocation of transmission capacity rights.

6.3 Reconfiguration Auction Outcomes

This section provides a review of reconfiguration auction outcomes in 2024, with results spanning Capacity Commitment Period (CC) 14 (2023/24) and through CCP 17 (2026/27).

Key Takeaways

Annual Reconfiguration Auction (ARA) prices were generally lower than FCA prices in 2024, generally driven by decreases in the Net Installed Capacity Requirement (NICR). CCP 17 is an exception to this pattern, with an increasing Net ICR in its first ARA and further increases in the upcoming second ARA. No notable zonal price separation occurred in ARAs held in 2024.

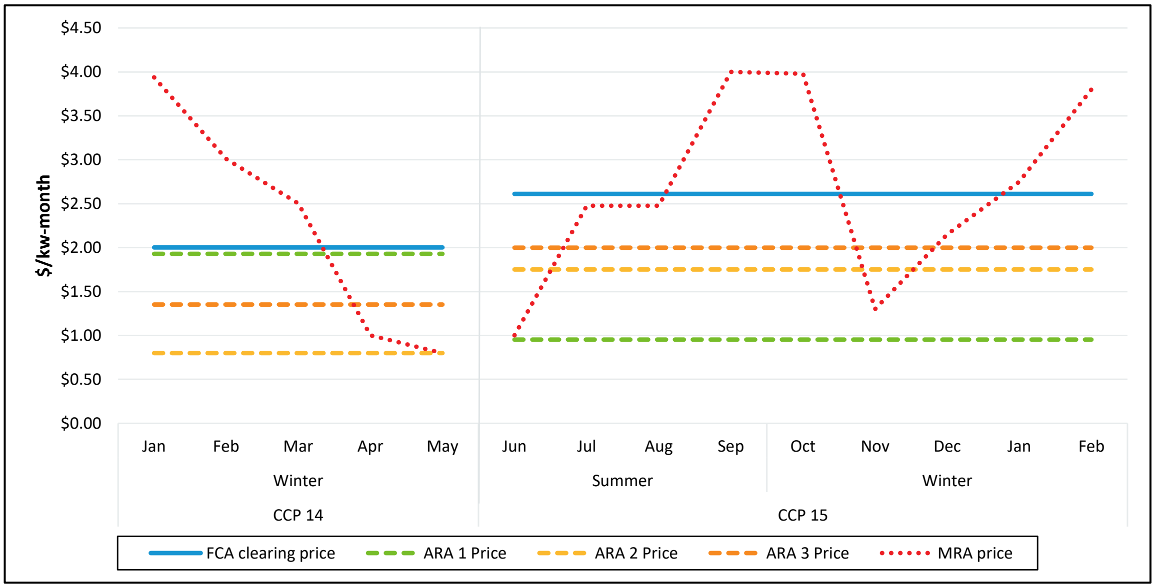
Monthly Reconfiguration Auction (MRA) prices varied between $0.80/kW-month and $3.98/kW-month in the rest-of-pool capacity zone throughout 2024. Zonal price separation occurred in the Southeastern New England (SENE) capacity zone in June through September, driven by high demand-side participation to shed Capacity Supply Obligations (CSOs) within the capacity zone.

Overall traded volumes in both ARAs and MRAs remained low as a share of total capacity.

6.3.1 Reconfiguration Auctions: CCP 14 and CCP 15

Monthly reconfiguration auctions covering the CCP 14-CCP 15 (2023/24 and 2024/25) period occurred throughout 2024. Figure 6-3 shows Monthly Reconfiguration Auction (MRA) rest-of-pool prices alongside Forward Capacity Auction (FCA) and Annual Reconfiguration Auction (ARA) rest-of-pool prices.

Figure 6-3: Reconfiguration Auction Prices for CCP 14-CCP 15



Annual reconfiguration auction rest-of-pool prices were below FCA clearing prices for CCP 14 and CCP 15, generally driven by decreasing Net Installed Capacity Requirements (Net ICR) for each auction relative to each FCA.[276] Monthly reconfiguration auction prices exhibited some variability, with prices ranging from $0.80/kW-month in May 2024 to nearly $4.00/kW-month in January 2024 and September through October 2024.

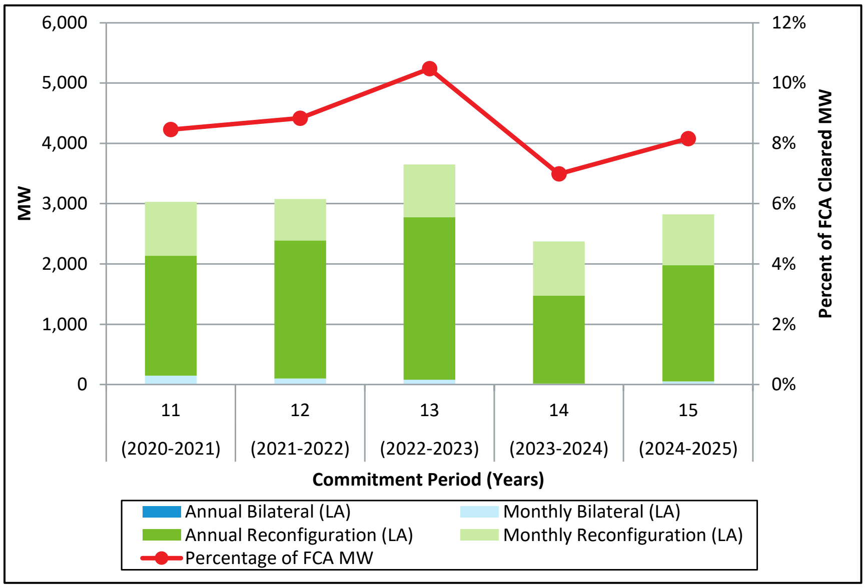
Price separation occurred in the import-constrained Southeastern New England (SENE) capacity zone for some reconfiguration auctions in CCP 15. SENE prices were marginally higher than FCA prices in ARA 3, and MRA SENE prices rose from June-September, reaching over $10/kW-month. These high MRA prices within SENE were driven by strong demand-side participation to shed capacity obligations within the capacity zone.

Traded volumes in reconfiguration auctions remained low as a share of total volumes acquired in FCAs. Figure 6-4 shows secondary auction volumes, with bars (left axis) showing traded MW

[276] For historical Net ICR values, see the ISO's *Installed Capacity Requirement* page, available at https://www.iso-ne.com/system-planning/system-plans-studies/installed-capacity-requirement.

amounts and a line (right axis) showing the percentage of FCA MW represented in secondary auctions from CCP 11-CCP 15.[277]

Figure 6-4: Traded Volumes in Reconfiguration Auctions



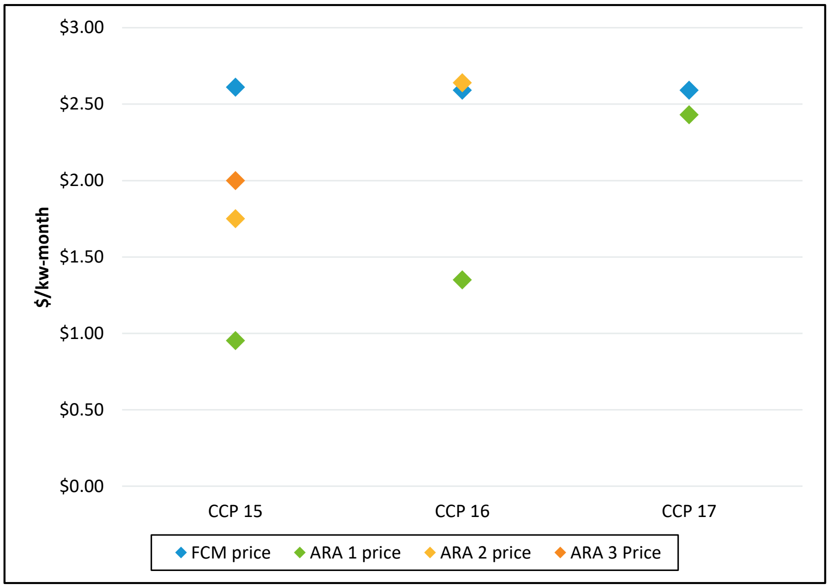
Reconfiguration auction volumes averaged between 6% and 8% of FCA auction volumes for CCPs 14-15. Most traded volumes continued to occur in annual reconfiguration auctions, with MRA trading representing less than 1,000 MW in both CCP 14 and 15 and less activity in annual or monthly bilateral auctions.

6.3.2 Annual Reconfiguration Auctions: CCP 15 (2024/25), CCP 16 (2025/26), and CCP 17 (2026/27)

The final ARA for CCP 15, the second ARA for CCP 16, and the first ARA for CCP 17 occurred in 2024. Figure 6-5 shows the rest-of-pool clearing prices for the FCAs 15-17 alongside the ARAs that have occurred so far for each commitment period.

[277] Volumes are calculated as annual averages. For example, MW traded in ARAs have a weight of 1, while MW traded in MRAs have a weight of 1/12.

Figure 6-5: Annual Reconfiguration Auction Prices, CCP 15-CCP 17



The third ARA for CCP 15 cleared at $2.00/kW-month, below the $2.61/kW-month clearing price of FCM 15. The Net ICR for ARA 3 fell to 31,380 MW from 33,270 MW in the primary auction. ARA 3 prices were slightly higher in the import-constrained Southeast New England capacity zone, which cleared at $2.01/kw-month.

The second ARA for CCP 16 cleared at $2.64/kW-month, slightly higher than the $2.59/kW-month clearing price of FCA 16. Prices were marginally higher despite a decrease in the Net ICR for CCP 16 (30,775 MW in ARA 2, down from 31,645 MW in FCA 16). No price separation occurred in the ARA.

The first ARA for CCP 17 cleared at $2.43/kW-month with no price separation across capacity zones. The lower clearing prices than FCA 17 ($2.59/kW-month) occurred despite a modest increase in Net ICR (30,395 MW in ARA 1, up from 30,305 in FCA 17). The Net ICR for the second ARA will increase again to 30,600 MW.

6.4 Pay-for-Performance Outcomes

Pay-for-Performance (PfP) is a two-settlement mechanism that credits or charges resources based on their performance in meeting energy and operating reserve requirements during periods when the system is deficient in Total 10- and 30-minute reserves. These periods are called Capacity Scarcity Conditions (CSCs).

Two distinct CSCs occurred in 2024, marking just the fourth and fifth occurrences since the PfP market rules were introduced in June 2018. The 2024 CSCs occurred on June 18 and August 1, driven by large generator trips on hot days with high loads.[278] The two events totaled 2.3 hours,

[278] Detailed analysis of the drivers of both events is available in the *Summer 2024 Quarterly Markets Report* (November 25, 2024), available at https://www.iso-ne.com/static-assets/documents/100017/2024-summer-quarterly-markets-report.pdf.

considerably more than the less than an hour of CSCs in 2023. CSC hours in 2024 were consistent with ISO forecasting models' predictions of reserve deficiency hours in CCP 15.[279]

Key Takeaways

Two Capacity Scarcity Conditions occurred in 2024, driven by unplanned generator outages on high-load summer days, resulting in a total of 2.3 hours of reserve deficiency throughout the year. The events were transitory in nature, with the system recovering quickly from operating reserve deficiencies of 500 to 600 MW (compared to a requirement of approximately 2,500 MW). The total amount of reserve deficiency hours was consistent with forecasting models for CCP 15.

PfP payments totaled approximately $63 million, a relatively small share (5%) of total capacity market payments of $1.2 billion. PfP payments are a transfer from under-performing resources to over-performing resources. Imports, both with and without capacity obligations (CSO), were the highest-performing resource type during both events. Steam turbine residual fuel oil generators were the worst-performing resource type due to generator trips during the events and long lead times preventing performance during the scarcity conditions. While steam turbine PfP losses outweighed CSO base payments in August, no generators reached stop loss limits in 2024.

Capacity resource performance is assessed based on the energy delivered and operating reserves provided during CSCs relative to the resource's CSO and the system's balancing ratio—the fraction of total contracted capacity needed to meet load and reserve requirements.

During the 2024 CSCs, the balancing ratio reached as high as 90%, indicating that 90% of total capacity obligations were required. For example, a resource with a 100 MW CSO would be financially obligated to provide 90 MW in the form of energy or reserves. Deviations from this target—either shortfalls or over-performance—are settled at the Performance Payment Rate of $5,455/MWh.

Capacity market settlements for the June 18 PfP event are aggregated by fuel type in Figure 6-6, while Figure 6-7 shows settlements for the August 1 event.[280]

[279] See *Operating Reserve Deficiency Information – Capacity Commitment Period 2024-2025,* By Fei Zeng, available at https://www.iso-ne.com/static-assets/documents/2020/12/a00_pspc_2020_12_iso_memo_or_def_fca_15.pdf. The ISO forecast 7.9 hours of reserve deficiencies at the FCA 15 Net ICR of 33,270 MW. FCA 15 cleared 34,621 MW of capacity, 1,351 MW above Net ICR. The ISO forecast between 2.8 and 3.7 hours of capacity deficiency at this level of capacity above Net ICR.

[280] In these figures, "DF" refers to dual-fuel assets and "CC" refers to combined-cycle generators. "ST – RFO" refers to steam turbine units burning residual fuel oil. Gas- or oil-fired units with fast-start capability are separated from similar units without fast-start capability. The "Other" category includes nuclear, coal, and wood or waste-fired units.

Figure 6-6: Pay-for-Performance Settlements, June 2024

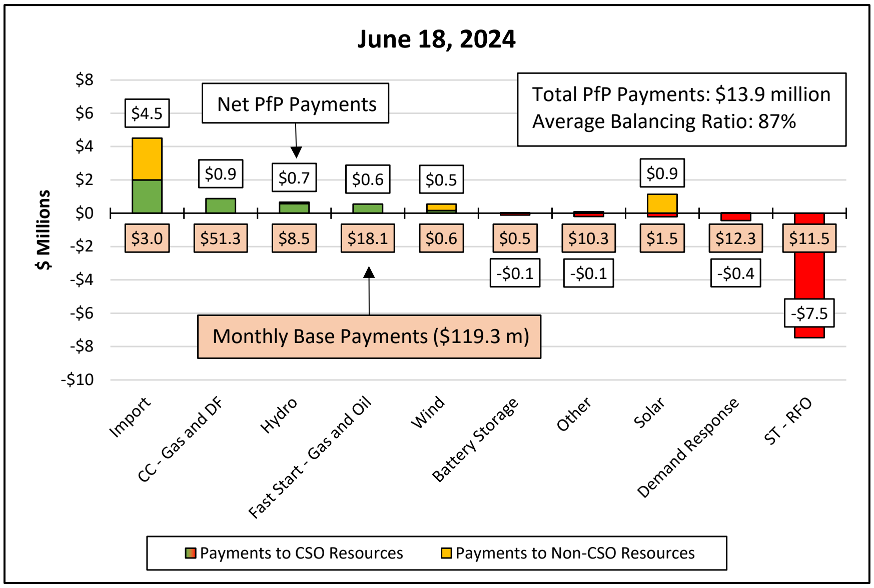
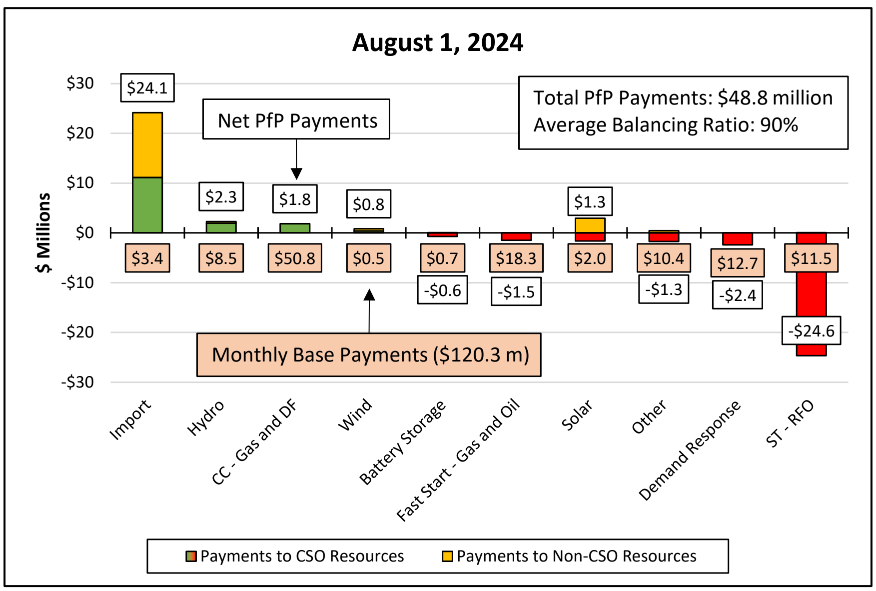


Figure 6-7: Pay-for-Performance Settlements, August 2024



Import transactions, both with and without CSOs, were the best-performing resource type in both events. Relatively reliable and efficient combined cycle and hydro units generally outperformed their CSOs in both events. Fast-start units performed near their CSOs, with slight overperformance in June and slight underperformance in August. While contracted solar units generally underperformed relative to their CSO due to the events occurring in the afternoon after peak solar hours, uncontracted solar received over $1 million in each event. Demand response units underperformed in both events, resulting in roughly $3 million in charges combined. Steam turbines burning residual fuel oil were the worst-performing resource type due to unit trips and long startup times. Notably, such units incurred losses on a net basis in

August as PfP penalties exceeded base CSO payments. While such units suffered financial losses, no individual resource triggered stop-loss limits in 2024.[281]

[281] Penalties to underperforming resources in PfP events are subject to monthly and annual stop-loss limits. Stop loss limits are a function of resource CSO and FCA starting prices. For more information on stop-loss limits, see ISO's *Section III Market Rule 1 Standard Market Design*, Section III.13.7.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

Section 7
Ancillary Services

This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. While there are six main types of ancillary services (listed below), this section focuses on real-time operating reserves, forward reserves, and regulation services.

The six main types of ancillary services are:

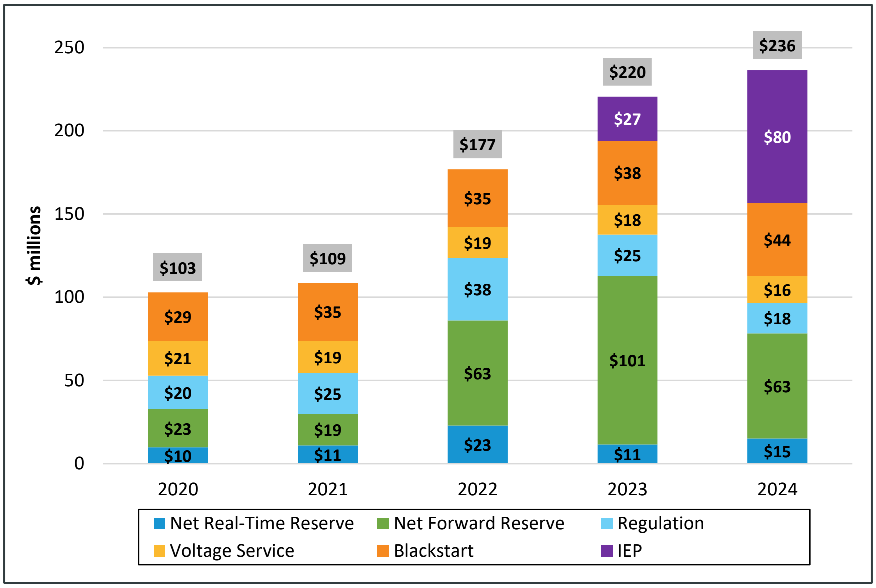
- *Real-time operating reserves* represent additional generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market (7.1).
- *Forward reserves* represent the procurement of offline operating reserves in advance of the delivery period; that is, the ability to start and ramp quickly in the event of system contingencies (7.2).
- *Regulation service* is provided by resources that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand and maintain system frequency levels in the real-time energy market (7.3).
- *Voltage support* helps the ISO maintain an acceptable range of voltage on the transmission system, and is necessary for the reliable flow of electricity. The ISO regulates voltage through reactive power dispatch, and the generators that provide this service receive voltage support payments.[282]
- *Blackstart service* is provided by generators that are able to start quickly without outside electrical supply. The ISO selects and compensates strategically-located generators for providing blackstart service. This service is necessary to facilitate power system restoration in the event of a partial or complete system blackout.
- The *Inventoried Energy Program (IEP)* began in December 2023. It incented and compensated inventoried energy during the winter seasons of 2023/24 and 2024/25.

Ancillary service costs by submarket are shown in Figure 7-1 below.[283] The gray boxes above each bar show the total ancillary service cost for each year.

[282] Transmission customers who use regional network service or through-or-out service incur voltage support charges. If the ISO commits a resource for voltage support in the energy market and it does not recover its effective offer, the resource is eligible for NCPC. The ISO Tariff contains detailed rules regarding compensation for voltage support. See *Section II ISO New England Open Access Transmission Tariff (the OATT)*, Schedule 2, available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[283] The Voltage Service category includes payments for capacity costs, lost opportunity costs, costs of energy consumed, and costs of energy produced.

Figure 7-1: Ancillary Service Costs by Product



Overall, ancillary costs in 2024 were the highest over the last five years, totaling $236 million, an increase of 7%, or $16 million, on 2023 ($220 million). The largest increase was in IEP costs, which rose by $53 million. These costs increased because the program began in December 2023, and 2024 was the first year where three winter months (January, February, and December) of costs were included in the total.

Lower net forward reserve costs offset some of the higher IEP costs. Net forward reserve costs were down by $38 million on 2023 due to lower clearing prices resulting from increased supply in the Winter 2024-2025 FRM auction, and lower requirements in the Summer 2024 auction. Regulation costs decreased by $7 million due to the increased participation of alternative technology resources (battery resources) in the market. Net real-time reserve costs increased by $4 million, as 2024 saw more shortage event hours (which result in very high reserve prices) than in 2023. Blackstart costs increased to $44 million from $38 million due to the annual rate adjustment for inflation of approximately 16.6%. Voltage service costs were similar to 2023 costs.

7.1 Real-Time Operating Reserves

The following section reviews real-time operating reserve products and outcomes. The first subsection (7.1.1) presents the reserve requirements that ISO maintains in the real-time energy market as well as the typical amount of reserve capability that is available in excess of those requirements. The second subsection (7.1.2) explores the frequency and magnitude of real-time reserve prices, including the frequency of reserve constraint penalty pricing, and summarizes the level of real-time reserve payments.

Key Takeaways

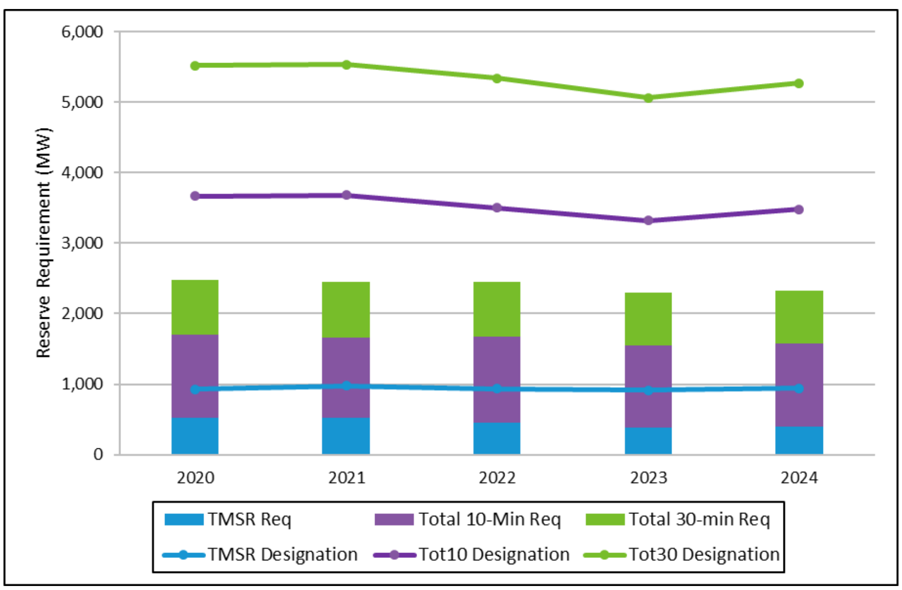
The system generally had ample reserve capability to satisfy reserve requirements throughout 2024, with two notable exceptions (discussed below). The average system reserve requirements in 2024 were effectively unchanged from 2023, and reserve margins increased slightly in 2024 relative to 2023 as a result fewer planned and unplanned outages of key resources.

During 2024, net real-time reserve payments totaled $15.1 million, a 32% increase from 2023. A key driver of these increased payments was the activation of reserve constraint penalty factors (RCPFs) on June 18 and August 1, when the system became deficient of ten- and thirty-minute reserves as a result of high temperatures, tight conditions, and unexpected losses of supply. Net real-time reserve payments on these two days accounted for roughly one third of all net reserve payments for the year.

7.1.1 Reserve Requirements and Margins

There are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Reserve requirements are based on the two largest contingencies on the system (commonly known as first and second contingencies). Figure 7-2 shows these system-level requirements, as well as the average reserves designated to satisfy these requirements.[284]

Figure 7-2: Average System Reserve Requirements and Designations



Reserve requirements in 2024 were effectively unchanged from 2023. Lower reserve requirements in 2023 and 2024 stemmed from smaller first contingency values driven by reduced imports across the Phase II DC tie with Hydro-Quebec, resulting in that source of energy supply being the largest contingency less frequently during 2023 (43% of hours) and 2024 (21% of hours) than in prior years. The region's nuclear generators were the largest

[284] There are also 30-minute local reserve requirements that are not shown or discussed below. These requirements bind infrequently, and thus are not impactful to system operations.

contingency in the majority of hours in 2024, and their output was a key factor in all reserve requirement calculations.

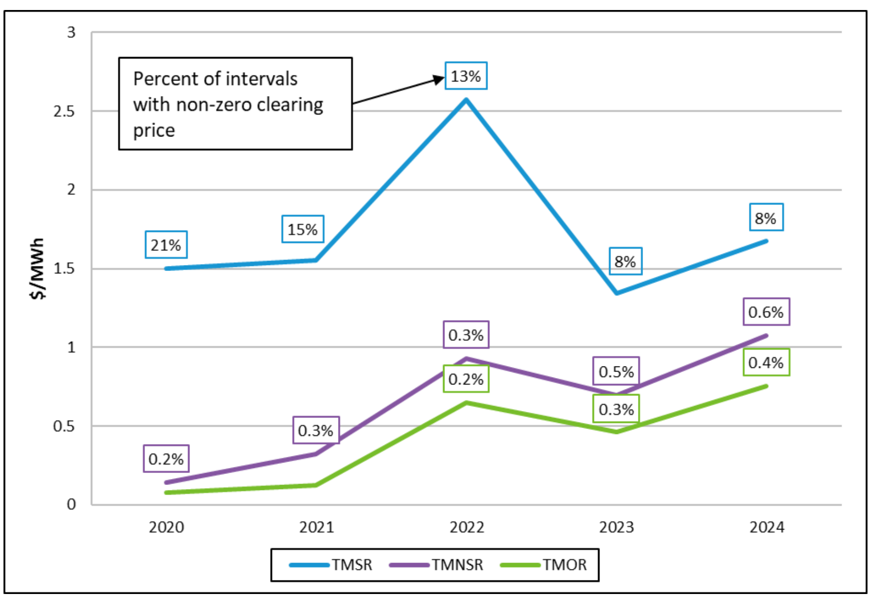
The reserve margin measures the reserve capability available in excess of reserve requirements (i.e., the distance between associated designation lines and bars in the figure above). On average, there has been a healthy surplus of reserve capability on the system compared to the requirements, though there were noteworthy periods during Summer 2024 when the region experienced deficiencies of reserves. These instances are included in the discussion of system events in Section 3.6.

Reserve margins showed modest (4%-7%) increases across requirements in 2024, relative to the prior year. These increased margins were driven by increased availability of key resources in 2024. Pumped-storage generators had significantly fewer planned outages in 2024 than in 2023, allowing these resources to make larger contributions to the supply of reserves. In addition, natural gas-fired generators also experienced fewer planned and unplanned outages in 2024, increasing the supply of reserves able to be designated on these resources when they are committed to provide energy.

7.1.2 Reserve Prices and Payments

Reserve prices occur when there is an opportunity cost of providing reserves rather than energy; in other words, when the market clearing engine must re-dispatch resources to maintain reserve requirements. This is an infrequent occurrence in New England, which has a large fleet of offline fast-start resources. Most of the time such re-dispatch is not necessary and, because reserve constraints are not binding, reserve clearing prices are $0/MWh. Figure 7-3 below shows both the frequency of non-zero reserve prices and the average value of reserve prices for all products at the system level.

Figure 7-3: Reserve Price Frequency and Average Value



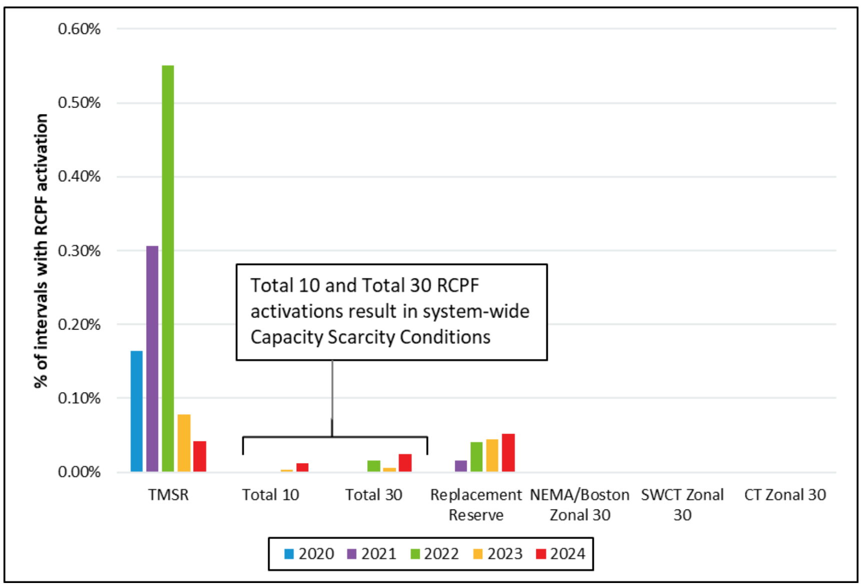
The frequency of non-zero reserve pricing, as indicated by the data labels in the figure above, was consistent with that observed in 2023. Average reserve prices, however, were higher on average in 2024 than 2023 across all products. This outcome indicates that when reserve constraints did bind, the re-dispatch necessary to maintain reserve requirements was costlier in 2024 than in 2023 (i.e., those resources 'held down' to provide reserves incurred greater opportunity costs, on average). A key contributor to higher average reserve prices in 2024 were the Capacity Scarcity Conditions that occurred during June and August. Average prices were \$1.67/MWh for TMSR, \$1.07/MWh for TMNSR, and \$0.76/MWh for TMOR in 2024.

The local thirty-minute reserve constraints did not bind at all during 2024. As a result, the local reserve zone reserve prices were equivalent to system-level reserve prices in all intervals.

Reserve Constraint Penalty Factors (RCPFs)

RCPFs for reserve constraints are "activated" and impact reserve prices when there is insufficient reserve capability to meet the reserve requirements, or when the cost of re-dispatch to satisfy those requirements exceeds RCPF values. The percentage of five-minute intervals during which the RCPF for each reserve constraint was activated is shown in Figure 7-4 below.

Figure 7-4: Reserve Constraint Penalty Factor Activation Frequency



The most significant RCPF activations of 2024 were the total 10- and total 30-minute reserve requirement RCPFs, which triggered Capacity Scarcity Conditions in June and August. The total 10-minute RCPF (\$1,500/MWh) was active for 65 minutes (1.1 hours), and the total 30-minute RCPF (\$1,000/MWh) was active for 130 minutes (2.2 hours). This level of activation is the highest observed in the study period. These activations were caused by hot weather and high loads coupled with unexpected generator outages.

The August CSC event was particularly notable due to its duration, which lasted for 110 minutes (1.8 hours). This is the longest CSC the system has experienced since the Labor Day event of September 2018.

The RCPF for the TMSR requirement (\$50/MWh) activated for 220 minutes (3.7 hours). This RCPF tends to activate more frequently than the RCPFs of other reserve constraints due to its relatively low value. In 2024, however, it activated far less frequently than in prior years, reflecting the increased TMSR margin noted in Section 7.1.1 above.

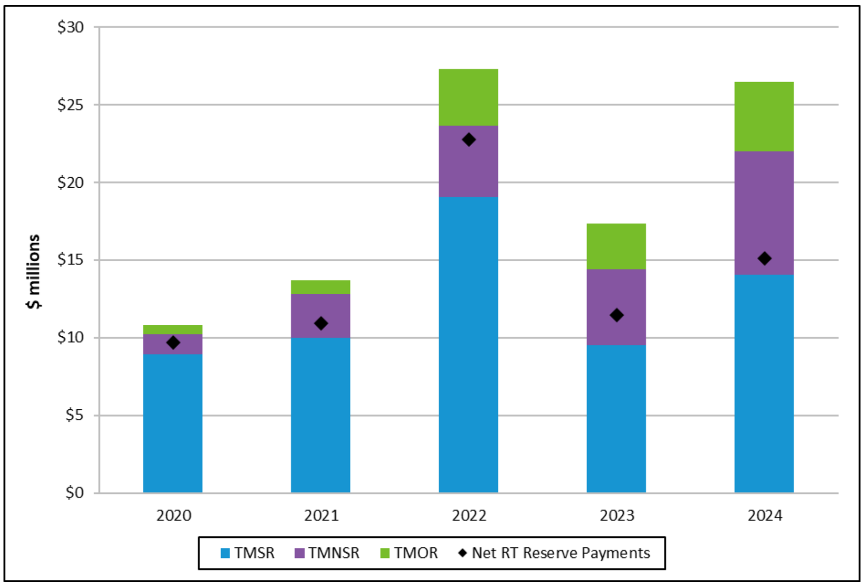
The replacement reserve RCPF ($250/MWh) activated in 270 minutes (4.5 hours) in 2024.

Reserve Payments

Real-time reserve payments are made to resources designated to provide operating reserves in intervals when reserve clearing prices are non-zero. Total real-time reserve payments are relatively small compared to overall energy market and capacity market payments.

Figure 7-5 below shows the total payments made for real-time reserves over the past five years, as illustrated by the stacked bars. The black diamond shows total net real-time reserve payments, and is reflective of the elimination of real-time reserve credits to forward reserve resources to ensure these resources are not double-compensated.

Figure 7-5: Real-Time Reserve Payments



Total gross real-time reserve payments in 2024 totaled $26.5 million. These gross payments were reduced for resources with a forward reserve market obligation, resulting in net real-time reserve payments of $15.1 million.[285] This is a 32% increase in net payments from 2023.

The most notable changes in 2024 relative to 2023 are the increase in TMNSR and TMOR payments, which stem primarily from the associated RCPF activations. Net real-time reserve payments in hours with these activations totaled $5.2 million, accounting for 34% of net reserve payments in 2024.

Fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over 125% in 2024. A detailed assessment of the impact of fast-start pricing is provided in Section 3.1.3 of this report.

[285] Section 7.2.3 discusses FRM payments.

7.2 Forward Reserves

We now assess outcomes in the Forward Reserve Market (FRM), which procures reserve products in advance of summer and winter seasons. Specifically, in this section we review the trends in auction demand quantities over the past five years (7.2.1), auction results (7.2.2), and the resulting levels of forward reserve payments (7.2.3). Importantly, the Forward Reserve Market ended with the implementation of the Day-Ahead Ancillary Services Initiative ("DASI") in March 2025.[286]

> ***Key Takeaways***
>
> Over the last few years, the quantities of reserve capability required in the FRM have been reasonably stable at the system level. Additionally, there has been no need for a local requirement in any local reserve zone due to transmission improvements.
>
> The FRM auctions that took place in 2024 resulted in generally lower clearing prices, and these lower clearing prices in-turn resulted in a year-over-year decrease in net FRM payments ($101.4 million in 2023 to $63.1 million in 2024). The lower prices came after FERC approved a market rule change in April 2024 that revised the FRM offer cap down. The IMM had recommended this market rule change given the low levels of structural competitiveness in recent auctions.

7.2.1 Market Requirements

The FRM auction procures ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) on a forward basis. The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for each procurement period. In addition to developing reserve requirements at the system level, the ISO develops reserve requirements at a zonal level as some zones within New England are constrained in terms of how much power they can import from other zones.[287]

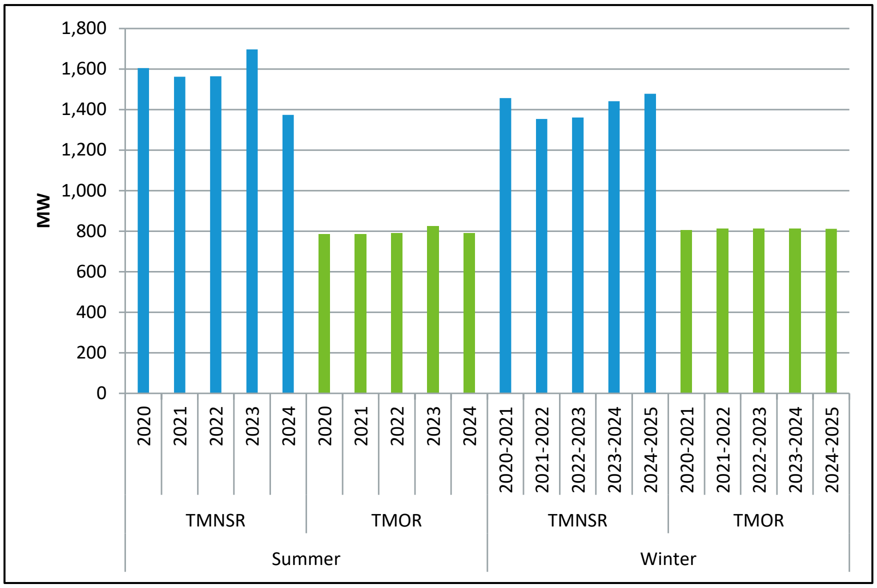
System Requirements

The system FRM requirements have been reasonably stable during the last five years. This can be seen in in Figure 7-6 below, which shows the system requirements from Summer 2020 through Winter 2024-25.

[286] More information about DASI can be found on the ISO's *Day-Ahead Ancillary Services Initiative (DASI)* page, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/day-ahead-ancillary-services-initiative .

[287] The currently defined reserve zones are Southwest Connecticut, Connecticut, and NEMA/Boston. See *ISO New England Manual for Forward Reserve and Real-Time* Reserve *Manual M-36* (effective date: December 3, 2019) , Section 2.2.1, available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf

Figure 7-6: Forward Reserve Market System-wide Requirements



Over the past ten auctions, the TMNSR purchase amount has represented the expected first contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected second contingency of either Mystic 8/9, Seabrook, or Millstone.[288] Therefore, the requirements have been relatively consistent around 1,350-1,700 MW for TMNSR and around 800 MW for TMOR. The small fluctuations in seasonal requirements reflect seasonal variation in the expected capabilities of the resources identified as the system contingencies, and relatively stable expectations for non-spinning reserve needs (affecting TMNSR), generator performance when called upon for system contingencies (affecting TMNSR), and replacement reserve needs (affecting TMOR).

Zonal Requirements

During the last ten auctions, there have been no zonal reserve requirements because there has been sufficient external reserve support (ERS) to alleviate the need for these requirements.[289] This results from a considerable increase in ERS for Connecticut and Southwest Connecticut due mainly to transmission upgrades. Similarly, transmission upgrades in NEMA/Boston have increased ERS for that area, resulting in no need for a local requirement in the last five summer and winter periods.

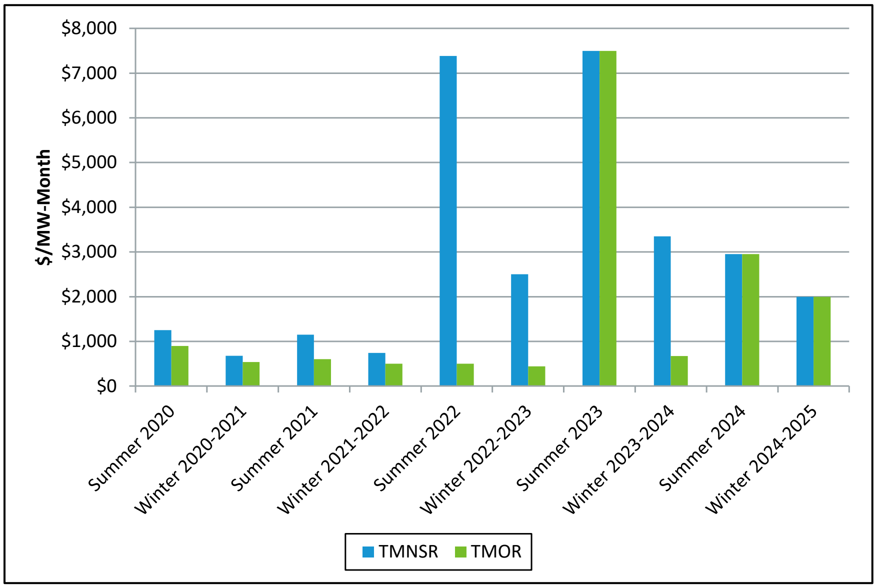
[288] As noted in the ISO's assumptions memoranda for the individual FRM auctions, the FRM system requirements may be biased up or down and, in the case of TMOR, include a replacement reserve adjustment. See the ISO's *Day-Ahead Ancillary Services Market and Real-Time Reserve Pricing* page, available at https://www.iso-ne.com/markets-operations/markets/reserves/?document-type=Forward Reserve Market Assumptions

[289] External reserve support (ERS) refers to the ability of a local reserve zone to obtain operating reserves from other reserve zones. The ERS reflects the amount of available transfer capability on the transmission interface for the local reserve zone. See *ISO New England Manual for Forward Reserve and Real-Time* Reserve *Manual M-36* (effective date: December 3, 2019) , Section 2.2.4, available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf

7.2.2 Auction Results

FRM auction pricing outcomes from the Summer 2020 auction through the Winter 2024-25 auction are shown in Figure 7-7 below.[290]

Figure 7-7: Forward Reserve Prices by FRM Procurement Period



FRM auction clearing prices moderated in 2024 with the summer and winter auction prices settling in around $2,000-$3,000/MW-month. This follows a recent stretch of elevated clearing prices, particularly in the summer season. TMNSR clearing prices rose drastically in Summer 2022 ($7,386/MW-month) and stayed elevated in Summer 2023 ($7,499/MW-month). TMOR prices also experienced a sharp price increase in the Summer 2023 auction ($7,499/MW-month).

These high auction clearing prices, which generally reflect increased offer prices, in combination with structural market power concerns,[291] led the IMM to recommend that the forward reserve offer cap price be reviewed and updated.[292] The ISO took up this recommendation and revised the offer cap down from $9,000/MW-month to $7,1000/MW-month.[293] FERC subsequently approved these rule changes and it was this lower offer cap that was effective for both FRM auctions that took place in 2024.[294]

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[290] Because there were no zonal reserve requirements, the clearing prices for each reserve product apply to all cleared supply offers for that product regardless of the zone associated with the offer.

[291] See Section 2.4.1 for more information related to the competitiveness of the Forward Reserve Market.

[292] The IMM's recommendation related to the forward reserve offer cap can be found in our *Spring 2023 Quarterly Markets Report* (August 1, 2023), Section 5.3.3: https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf

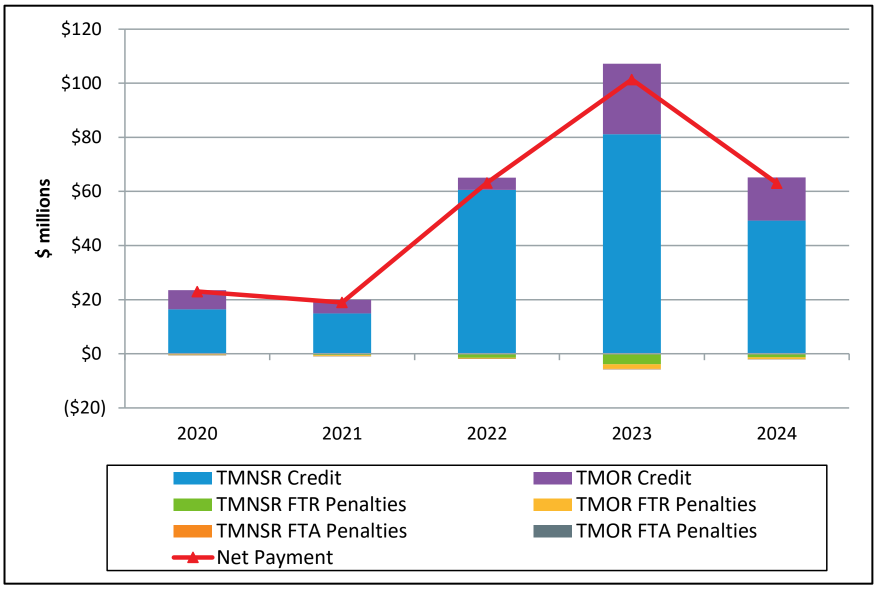
[293] See *Revisions to ISO New England Transmission, Markets and Services Tariff to Revise Forward Reserve Market Offer Cap and Offer Data Publication Timeline* (February 14, 2024), available at https://www.iso-ne.com/static-assets/documents/100008/er24-1245-000_2-14-24_frm_offer_cap_and_offer_data_pub_timeline.pdf

[294] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap*, ER24-1245-000 (April 12, 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf

7.2.3 FRM Payments

Annual FRM payment and penalty data over the past five years are provided in Figure 7-8 below. The figure indicates the annual auction-based payments, which are based on auction obligations and auction clearing prices, as positive stacked bar values. Meanwhile, penalties are shown as negative stacked bar values. FRM participants face two types of penalties: (1) failure-to-reserve (FTR) penalties, which occur when a participant's assignments to resources are less than the participant's FRM obligation, and (2) failure-to-activate (FTA) penalties, which occur when a resource that has been assigned an FRM obligation fails to provide energy when called upon by the ISO. The net payment is depicted by the red line.

Figure 7-8: FRM Payments and Penalties by Year



Net forward reserve payments decreased significantly, falling from $101.4 million in 2023 to $63.1 million in 2024. This was due to the generally lower TMNSR and TMOR auction clearing prices discussed in the prior section. Total TMNSR credits in 2024 amounted to $49.3 million, while total TMOR credits in 2024 amounted to $15.9 million. Meanwhile, penalties have been low relative to gross payments and have been stable in the 2% to 5% range of total payments over the period. These penalties have been predominately for failing to reserve (96% in 2024).

7.3 Regulation

In this section, we examine the participation, outcomes, and competitiveness of the regulation market. Specifically, we review the amount of regulation capability needed by the ISO (7.3.1), and regulation clearing prices and payments (7.3.2).

Key Takeaways

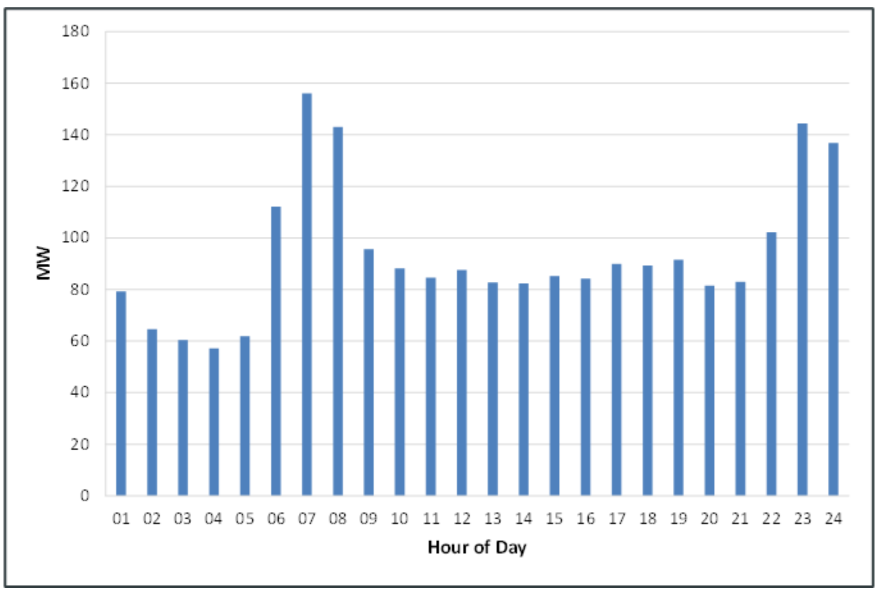
Regulation requirements in 2024 were similar to 2023, averaging just over 90 MW of regulation capacity per hour. The resource mix of cleared regulation capacity has changed significantly over the review period. In 2020, alternative technology regulation resources (mainly batteries) accounted for 24% of cleared capacity. In 2024, these resources accounted for 81% of cleared capacity.

The regulation market produces two clearing prices: for capacity and service. Clearing prices for capacity, which made up about 90% of the overall market value, decreased from \$23.48/MWh in 2023 to \$15.30/MWh in 2024, reflecting a decrease in offer prices. Regulation service prices decreased from \$0.13/mile in 2023 to \$0.08/mile in 2024. Regulation payments decreased by 26% in 2024, reflecting the decrease in capacity and service prices. Regulation payments in 2024 totaled \$18.5 million, compared to \$25.1 million in 2023.

7.3.1 Regulation Requirements, Resource Mix, and Performance

The regulation *requirement* in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2024 is shown in Figure 7-9 below.

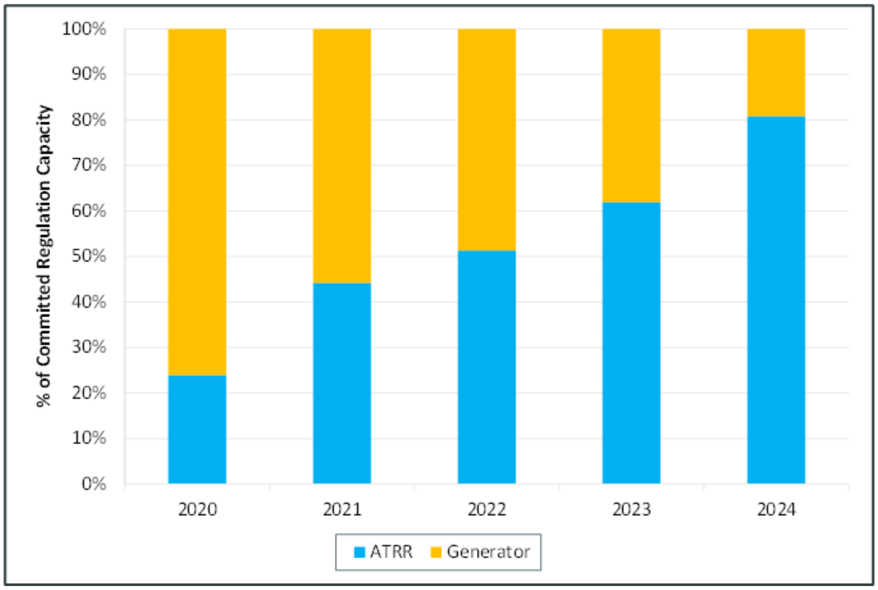
Figure 7-9: Average Hourly Regulation Requirement, 2024



The average hourly regulation requirement was 93.5 MW in 2024, a negligible change from the 2023 requirement (92.8 MW). Two different types of resources can provide regulation in the ISO's regulation market: traditional generators and alternative technology regulation resources (ATRRs). Almost all of the ATRRs are battery resources that may function solely as regulation resources or may operate as a combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation.

The regulation market resource mix for 2020 to 2024 is shown in Figure 7-10 below.

Figure 7-10: Regulation Resource Mix



The *resource mix* for regulation has changed significantly. In 2020, ATRRs (blue shading) provided 24% of cleared regulation capacity. By 2024, ATRRs provided 81%. This change follows continuing increases in the installed capacity of battery resources in the ISO's markets. Regulation capacity available from ATRRs has increased from 45 MW to 224 MW over the period. The change in resource mix also supports the finding that battery resources are lower-cost regulation resources (i.e., have lower-cost regulation market offers), as these ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

Finally, regulation *performance* is measured relative to a NERC standard. With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO uses violations of Balancing Authority ACE Limits (BAAL) to measure performance, which are defined as exceedances of ACE limits for more than 30 consecutive minutes. In 2024, there were no BAAL violations.

7.3.2 Regulation Prices and Payments

Regulation Clearing Prices (RCP) are based on the regulation offer of the highest-priced generator providing the service. There are two types of regulation clearing prices: "service" and "capacity."[295] Clearing prices for the past five years are shown in Table 7-1 below.[296]

[295] The service price represents the direct cost of providing the regulation service (also known as regulation "mileage"). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service. The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service, (2) the value of intertemporal opportunities that would be lost from providing regulation, (3) elements of fixed costs such as incremental maintenance to ensure a generator's continued performance when providing regulation, and (4) fuel market or other risks associated with providing regulation.

[296] The prices in the table are simple average prices for each year.

Table 7-1: Regulation Prices

Year	Regulation Capacity Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)		
	Min	Avg	Max	Min	Avg	Max
2020	0.40	16.12	396.08	0.00	0.21	10.00
2021	0.00	19.23	699.11	0.00	0.21	10.00
2022	0.00	30.96	1,068.09	0.00	0.27	10.00
2023	0.00	23.48	649.11	0.00	0.13	10.00
2024	0.00	15.30	2,354.17	0.00	0.08	4.59

Regulation capacity prices decreased by 35% in 2024, reflecting a decline in offer prices as lower-cost ATRRs continue to make up a larger share of the regulation mix. Regulation service prices also decreased compared to 2023. In 2024, the average service price was $0.08/mile, down $0.05/mile compared to the prior year. As with the decline in regulation capacity prices, the service price was lower relative to earlier periods due to the increased participation of ATRRs in the regulation market, which often offer at $0/mile. The highest regulation capacity clearing price of 2024 occurred during the August 1 capacity scarcity conditions due to high opportunity costs (high LMPs).

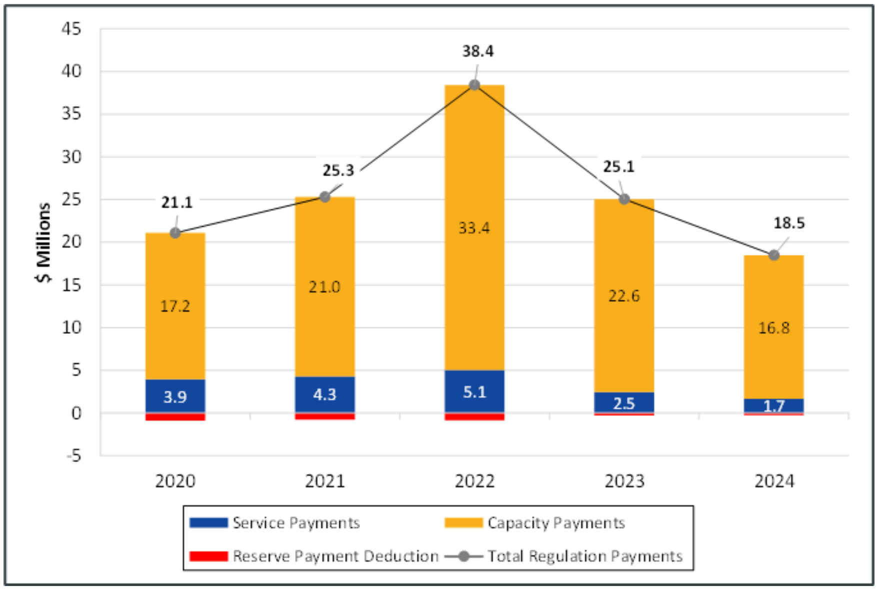
Regulation Payments

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, a make-whole payment, and an operating reserve adjustment.[297] Annual regulation payments over the past five years are shown in Figure 7-11 below.[298]

[297] The operating reserve adjustment represents a deduction to regulation payments. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since generators do not actually provide operating reserves within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

[298] The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period. The make-whole payment is included in capacity payment totals, since it represents an uplift payment when the capacity payments do not fully compensate resources for energy market opportunity costs.

Figure 7-11: Regulation Payments



Payments to regulation resources totaled $18.5 million in 2024, 26% less than the $25.1 million in 2023 (these totals exclude the reserve payment adjustment). The decrease in 2024 payments resulted primarily from a 26% decrease in capacity payments, consistent with the above-noted decrease in capacity prices (35%). Lower regulation service prices and payments ($0.8 million decrease in service payments) in 2024 also contributed to the overall decrease in regulation payments. Capacity payments made up 81% to 91% of overall regulation payments during the reporting period.

Section 8
Transmission Congestion and Financial Transmission Rights

This section covers trends in transmission congestion and financial transmission rights (FTRs), which are ISO-administered financial tools that can be used to manage congestion risk or take positions on congestion.

8.1 Transmission Congestion

Below, we examine transmission congestion in New England over the last five years. We first look at the level of congestion revenue and then explore where the congestion is occurring in the New England power system.

> ***Key Takeaways***
>
> In 2024, congestion revenue totaled $36.9 million, representing only 0.66% of total energy costs. This low level of congestion revenue was the result of relatively low energy prices and a generally unconstrained transmission system.
>
> Levels of transmission congestion are relatively low in New England compared to other ISO markets due to the significant amount of reliability-driven transmission investment over the past decade.[299] That being said, there are some specific areas within the New England System that periodically experience transmission congestion, many of which have relatively high concentrations of wind generation. Additionally, the main interconnection interface with New York (the New York - New England or "NYNE" interface) continues to be constrained at times, limiting the flow of power between the two regions.

Congestion Revenue

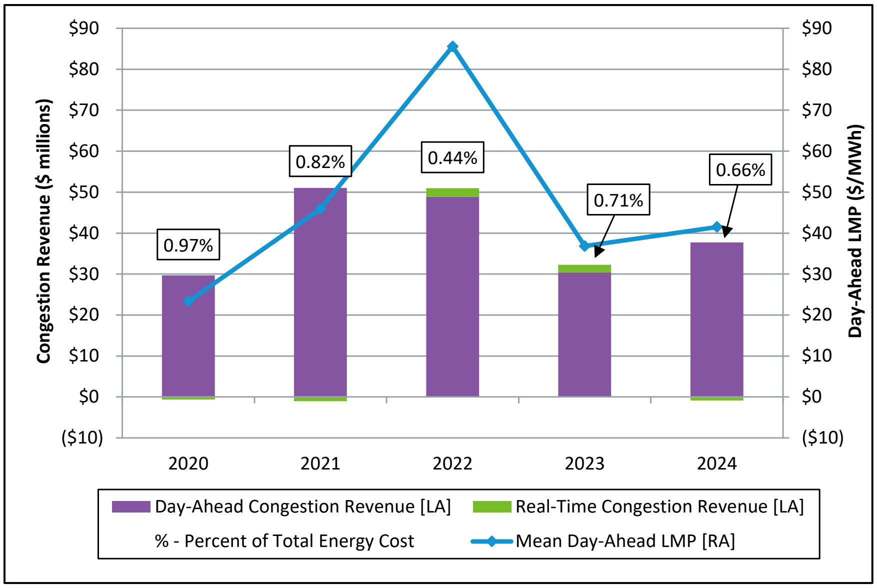
Put simply, congestion revenue represents the difference between what load pays for energy and what generation receives for energy that happens because of transmission congestion.[300] A feature of New England's locational energy market is that load pays for energy at the price where it is *consumed,* and generation is paid at the price where it is *produced*. This means that, when there is a binding transmission constraint limiting the production of less expensive generation, load will often pay more for the energy that it consumes than generation receives for the energy that it produces. This excess revenue forms the basis for payments to FTRs, which are covered in more detail in Section 8.2.

[299] Potomac Economics' (the External Market Monitor for ISO-NE) *2023 Assessment of the ISO New England Electricity Markets* (June 2024) showed that ISO-NE had the lowest congestion rate between 2021-2023 ($0.37/MWh) among a set of RTOs that included ERCOT, ISO-NE, MISO, NYISO, and PJM. However, ISO-NE had the highest transmission rate in 2023 ($22.0/MWh) of these RTOs. See Figure 2 in its *2023 Assessment*¸ available at https://www.potomaceconomics.com/wp-content/uploads/2024/07/ISO-NE-2023-EMM-Report_Final.pdf.

[300] For an exact definition of day-ahead and real-time congestion revenue, see *Section III Market Rule 1 Standard Market Design*, Section III.3.2.1(i), available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Over the last five years, congestion revenue has been small relative to total energy market payments, and it has generally moved in line with the price of energy. This can be seen in Figure 8-1 below.[301]

Figure 8-1: Average Day-Ahead Hub LMP, Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $36.9 million in 2024, or just 0.66% of total energy costs. Generally, most of congestion revenue stems from the day-ahead market where the vast majority of load and generation clear. Real-time congestion revenue tends to be much smaller given that it is based on real-time energy market *deviations*. In 2024, day-ahead congestion revenue totaled $37.8 million, while real-time congestion revenue totaled -$0.9 million. As can be seen in the figure, the day-ahead congestion revenue totals tend to be strongly correlated with the average day-ahead Hub LMP.

Congested Areas in New England

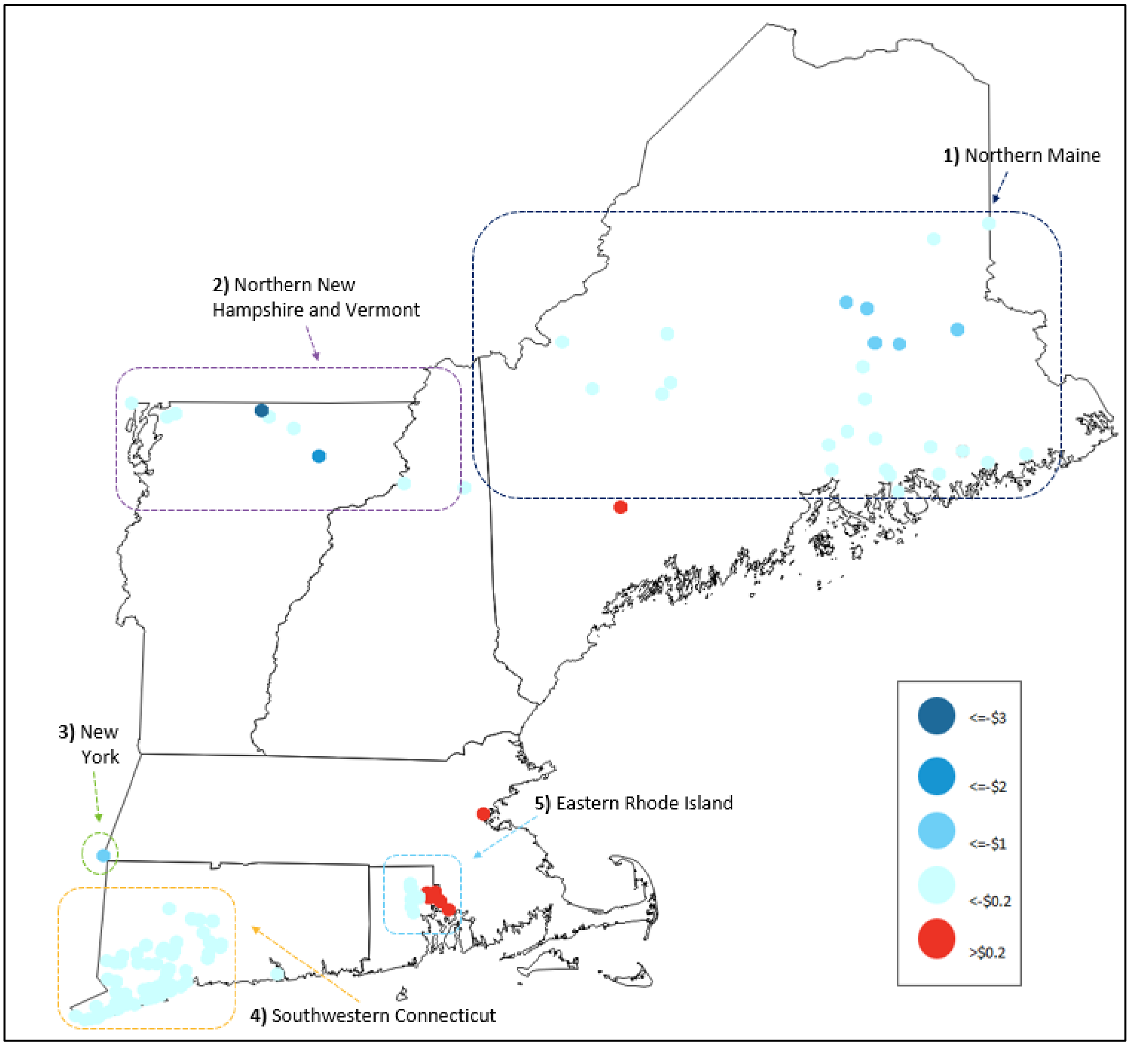
The New England pricing nodes most affected by transmission congestion in the day-ahead market in 2024 are shown in Figure 8-2 below.[302] Locations that are "upstream" of a binding transmission constraint have a negative congestion component, while locations that are "downstream" of a binding constraint have a positive congestion component.[303]

[301] The percentages in the figure are the total congestion revenue each year (i.e., the day-ahead congestion revenue plus the real-time congestion revenue) expressed as a percent of total energy market costs. Additionally, the designation 'LA' in the legend indicates that the value is measured by the y-axis on the left side, while 'RA' indicates that the value is measured by the y-axis on the right side.

[302] In order to highlight the constrained areas, this figure only includes nodes that had an average day-ahead congestion component in 2024 of greater than or equal to $0.20/MWh or less than or equal to -$0.20/MWh.

[303] More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint. In simple terms, a shift factor measures how an injection of energy at a location impacts the flow of energy over a transmission constraint. In other words, locations with a positive shift factor indicate that an injection of energy at that location would *exacerbate* transmission congestion. Conversely, a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In other words, locations with a negative shift factor indicate that an injection of energy at that location would *alleviate* transmission congestion.

Figure 8-2: New England Pricing Nodes Most Affected by Congestion, 2024



Many of the congested areas in New England in 2024 were relatively small geographic areas where transmission capacity limited the ability to export power to the rest of the system. Several areas in Figure 8-2 have been highlighted and each of them is discussed in detail below:

1) **Northern Maine**: This area has a relatively high concentration of intermittent (predominantly wind) generators and is also where the New England system interconnects to the New Brunswick control area (i.e., imports from New Brunswick flow into this area). Transmission constraints that created congestion in this area included: the Keene Road Export ("KR-EXP") interface, the Orrington-South ("ORR-SO") interface, and the Rumford Export ("IRMF-E") interface.

2) **Northern New Hampshire and Vermont**: Similar to northern Maine, northern New Hampshire and Vermont are areas with relatively high concentrations of wind generation. Additionally, northern Vermont receives the power imported from the Hydro-Québec control area over the Highgate tie line. Transmission constraints that created congestion in this area included: the Kingdom Wind Generation ("KCW")

interface, the Sheffield Generation ("SHEF") interface, and the Sheffield + Highgate Export ("SHFHGE") interface.

3) **New York**: The lines connecting New York and New England frequently reach their limit during periods when there are large price differences between the regions (e.g., some winter months when New England's gas infrastructure can become constrained resulting in higher New England prices) or when there are reductions in the interface limit. Transmission constraints that created congestion in this area included: the New York - New England ("NYNE") interface.

4) **Southwestern Connecticut**: Multiple high capacity and efficient natural gas-fired generators have been added in this region in recent years resulting in increased in-merit supply. At times, the 115-kV system can limit the export of low-cost power out of this region to the rest of the system, especially when nearby transmission lines are taken out of service for repair or upgrade work. Transmission constraints that created congestion in this area included the Bunker Hill 1029-2 line and the Berlin 1670-2 line.

5) **Eastern Rhode Island**: This region near Providence, Rhode Island, experiences periodic congestion on the 115-kV system. At times, this can happen when there are pipeline gas price differences such that more gas-fired generation on the west side of the constraint is committed than on the east side of the constraint. Many of the units on the east side of the constraint get their gas from the G lateral on the Algonquin pipeline system, which is frequently more expensive than the non-G price. Transmission constraints that created congestion in this area included: the Hartford Avenue E105 and F106 lines.

8.2 Financial Transmission Rights

The assessment of financial transmission rights (FTRs) activity and performance is structured as follows: (8.2.1) FTR auction volumes, (8.2.2) FTR funding, and (8.2.3) FTR profitability at a market level. Given their outsized impact on FTR market outcomes, special attention is given to FTR paths that source from .I.ROSETON 345 1 ("Roseton"), which is ISO-NE's external node for trading across the New York - New England ("NYNE") interface.[304]

Key Takeaways

The average number of FTR MWs held in 2024 (34,066 MWs per hour) represented a slight increase from the prior year. FTRs were fully funded in 2024, meaning there was sufficient revenue collected through the energy markets' congestion revenue fund to pay FTR holders. After an unprofitable year in 2023 (-$14.1 million), FTR holders made a collective profit of just $1.5 million in 2024. This is despite a third consecutive year in which FTRs sourcing from Roseton incurred large losses ($6.8 million in 2022, $11.0 million in 2023, and $6.8 million in 2024).

8.2.1 FTR Volume

The volume of FTRs that participants hold depends on a number of factors, including participants' expectations of congestion in the day-ahead market. If participants expect more congestion in the day-ahead market than in prior years, they may purchase more MWs of FTRs

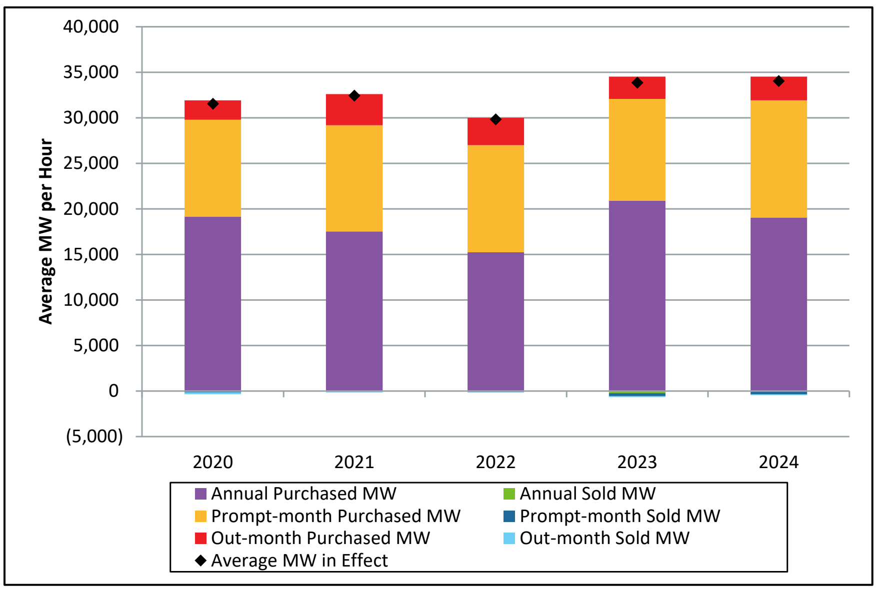
[304] I.ROSETON 345 1 is represented by area 3 in Figure 8-2 above.

to hedge against this expected congestion. Conversely, if participants expect less congestion in the day-ahead market, they may purchase fewer MWs of FTRs.

Another important factor is the set of transmission limits that the ISO uses in the auctions it conducts to award FTRs. The ISO performs a market feasibility test in each FTR auction that ensures that the awarded set of FTRs respects the transmission system's physical and operational limits.[305] Essentially, these limits restrict the MW volume of FTRs that can be purchased in FTR auctions, which helps ensure that there will be sufficient congestion revenue from the energy market to pay FTR holders.

Participants held more FTRs (by MWs) per hour, on average, in 2024 than in any other year over the reporting period. This observation can be seen in Figure 8-3, which shows the average MW volume of FTRs that were in effect each hour by year (black diamonds) for the past five years.[306] This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type (i.e., annual, prompt-month, or out-month) during each year.[307] FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

Figure 8-3: Average FTR MWs in Effect per Hour by Year



Market participants held an average of 34,066 MWs of FTRs per hour in 2024, representing a 1% increase from the average amount of FTRs in effect in 2023 (33,881 MWs per hour). This growth was the result of increased purchases in the monthly auctions: average prompt-month

[305] This test is performed in order to increase the likelihood of revenue adequacy, which means that there is sufficient congestion revenue collected in the energy market and from FTR holders with negative target allocations to fully compensate all FTR holders with positive target allocations. This is further discussed in Section 8.2.2.

[306] The averages are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

[307] An *annual* auction refers to an auction where participants purchase (or sell) FTRs whose term is one calendar year, while both *prompt-month* and *out-month* auctions refer to auctions where participants purchase (or sell) FTRs whose term is one month. P*rompt-month* refers to the monthly auctions for FTRs that are in effect for the month immediately after when the auction takes place, while *out-month* refers the monthly auctions for FTRs that are in effect for any other month remaining in the calendar year (excluding the prompt month).

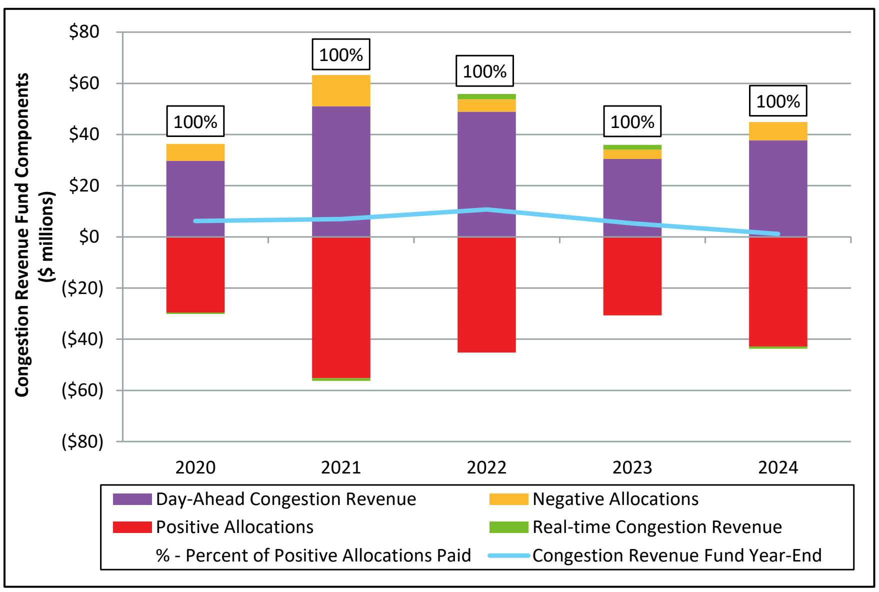
FTR purchases increased by 15% in 2024 (12,872 MWs per hour) compared to 2023 (11,201 MWs per hour), while average out-month FTR purchases increased by 6% in 2024 (2,594 MWs per hour) compared to 2023 (2,594 MWs per hour). Meanwhile, purchases in annual auctions decreased year-over-year, falling 9% from 2023 (20,884 MWs per hour) to 2024 (19,056 MWs per hour). In general, FTR holders sell very few FTRs each year (just 456 MWs per hour on average in 2024), as can be seen below the horizontal axis in Figure 8-3.

8.2.2 FTR Funding

FTR funding refers to the ability to pay FTR holders the full value of their positive target allocations. Positive target allocations arise when the congestion component at the sink location (point of delivery) of an FTR path is larger than the congestion component at the source location (point of injection). When there is sufficient revenue to pay all the positive target allocations, FTRs are said to be *fully funded*. Fully funding FTRs is an important aspect of a well-functioning FTR market because it gives market participants confidence that they will receive the full value of their FTRs.

FTRs were fully funded in 2024 and have been in each of the last five years, as can be seen in Figure 8-4 below. The graph shows, by year, the different components of the congestion revenue fund ("CRF"), including: congestion revenue from the day-ahead and real-time energy markets and positive and negative target allocations.[308] The balance in the CRF at the end of each year is shown by the blue line.[309]

Figure 8-4: FTR Funding and Congestion Revenue Fund Components by Year



[308] The CRF is used to pay FTR holders with positive target allocations. This fund collects money from three sources: (1) day-ahead congestion revenue, (2) real-time congestion revenue, and (3) the holders of FTRs with negative target allocations. For more information about transmission congestion revenue and FTR funding, see *Section III Market Rule 1 Standard Market Design*, Section III.5, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

[309] The CRF balance is defined here as the ∑[day-ahead congestion revenue + real-time congestion revenue + abs(negative target allocations) – positive target allocations].

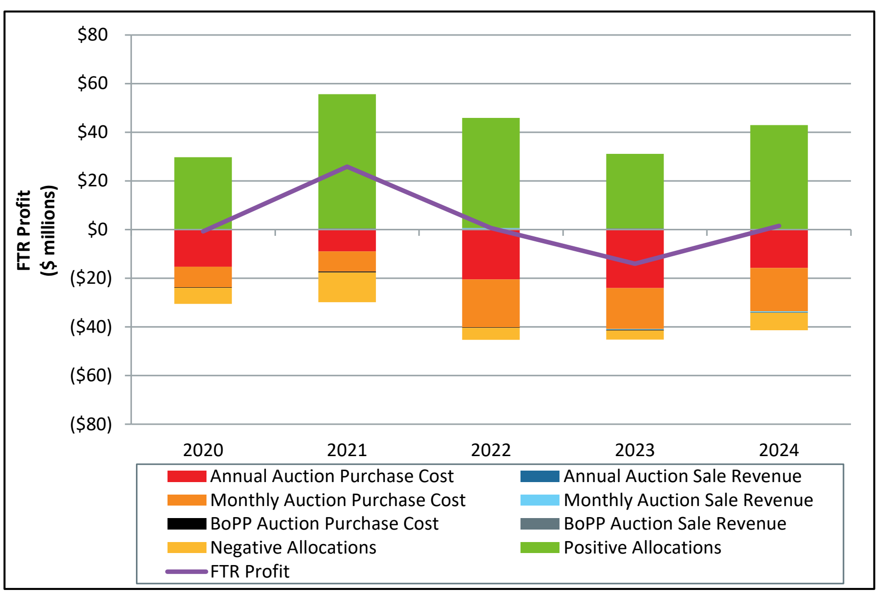
Day-ahead congestion revenue increased in 2024 ($37.8 million) from its 2023 value ($30.4 million). Meanwhile, real-time congestion revenue fell from $1.9 million in 2023 to -$0.9 million in 2024. Positive target allocations in 2024 ($42.9 million) increased by $12.2 million from their 2023 value ($30.7 million). Negative target allocations in 2024 ($7.2 million) increased significantly from their 2023 value ($3.7 million). The CRF year-end balance at the end of 2024 was $1.2 million; this surplus was distributed proportionately to entities that paid congestion costs during the year.[310]

8.2.3 FTR Profitability

Overall profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus the negative target allocations and the cost of FTR purchases. In a competitive FTR market, one would not expect to see excessive (risk-adjusted) profits or losses sustained over numerous years. Prolonged periods of high profitability would likely spur the entry of new participants (or at least an increase in FTR bid prices among existing participants), raising the cost to purchase FTRs and reducing FTR profitability. Conversely, prolonged periods of losses might motivate existing participants to exit the market (or at least decrease their FTR bid prices), lowering the cost to purchase FTRs and increasing FTR profitability.

As a group, FTR holders were profitable in 2024. Figure 8-5 below shows total profit (purple line) as well as each of the different profit components. In this figure, FTR sales revenue and positive target allocations are shown as positive values (as they increase FTR profitability), while FTR purchase costs and negative target allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

Figure 8-5: FTR Costs, Revenues, and Profits



[310] In 2024, the participants that received this money included generator owners, participants that engaged in external and virtual transactions, and load-serving entities, among others. For more information about the distribution of excess congestion revenue see *Section III Market Rule 1 Standard Market Design*, Section III.5.2.6, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

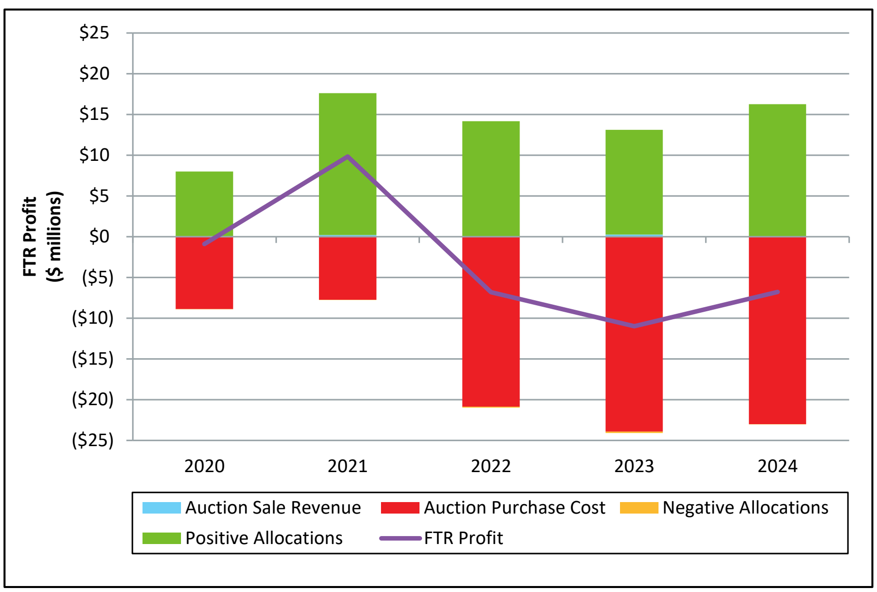
In 2024, total FTR profits amounted to $1.5 million. This represents a substantial change from 2023 when FTRs were unprofitable (-$14.1 million). An increase in positive target allocations was one of the primary drivers for increased profits. Positive target allocations totaled $42.9 million in 2024, which was 40% more than their value in 2023 ($30.7 million). At the same time, participants spent less to acquire their FTRs in 2024 ($33.8 million) than they did in 2023 ($41.2 million).

Congestion on the New York – New England Interface

Changes in profitability of FTRs that source from Roseton can contribute significantly to overall FTR market outcomes. This is partly because the NYNE interface tends to be one of the most frequently binding transmission constraints in the day-ahead market. Many of the participants that purchase FTRs that source from Roseton also import power over the New York North interface and use these FTRs to hedge against negative congestion pricing in the day-ahead market. To provide some perspective, the purchase costs for FTRs sourcing from Roseton represented 68% of all the FTR auction purchase costs in 2024, while the positive target allocations for FTRs sourcing from Roseton represented 38% of all positive target allocations.

FTRs sourcing from Roseton were unprofitable in 2024. This can be seen in Figure 8-6 below, which shows the total annual profits (purple line) for these FTRs over the last five years. This figure also shows the associated purchase costs, sale revenues, and positive and negative target allocations.

Figure 8-6: FTR Profits and Costs for FTRs Sourcing from Roseton



The losses associated with FTRs that source from Roseton shrank between 2023 (-$11.0 million) and 2024 (-$6.8 million). This moderation in losses was largely the result of an increase in positive target allocations associated with this group of FTRs; the holders of these FTRs received $3.4 million more in positive target allocations in 2024 ($16.2 million) than they did in 2023 ($12.9 million). The increase in positive target allocations coincided with an increase in the frequency with which the NYNE constraint bound in the day-ahead market (10.9% of hours in in 2024 compared to 7.5% of hours in 2023).[311] At the same time, participants paid $0.9 million less to acquire FTRs sourcing from Roseton in 2024 ($23.0 million) than they did in 2023 ($23.9 million).

[311] For more information about external transactions, see Section 4.

Section 9
Market Design or Rule Changes

This section provides an overview of the major market design and rule changes that were recently implemented or are being considered or planned for future years. The section also summarizes notable long-term studies that will have market and operational implications for the future grid. Table 9-1 below lists the design changes summarized in this section.[312]

Table 9-1: Market Design or Rule Changes

Major Design or Rule Changes Recently Implemented	Major Design or Rule Changes in Development or Implementation for Future Years
Forward Reserve Market Offer Cap	Fuel Price Adjustment Modifications
FCA 19 Delay	FERC Order 2222, Distributed Energy Resources
Day-Ahead Ancillary Services Initiative	Capacity Auction Reforms

9.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

9.1.1 Forward Reserve Market Offer Cap

In February 2024, the ISO filed changes to adjust the FRM Offer Cap and to revise the FRM data publishing timeline. The Offer Cap was changed from $9,000/MW-month to $7,100/MW-month, and the publication of offer data was shifted from the first day of the fourth calendar month following the month during which the applicable demand bids and supply offers were in effect to the first day of the twelfth calendar month following the month during which the applicable demand bids and supply offers were in effect. These changes were made in response to concerns raised by the IMM regarding the competitiveness of the FRM.

These changes were accepted by FERC in April 2024,[313] and were effective for the Summer 2024 Forward Reserve Auction.

9.1.2 FCA 19 Delay

In November 2023, the ISO proposed to delay FCA19 by one year. In April 2024, the ISO proposed to further delay FCA19. Under this proposal, FCA19 will be run in February 2028. The purpose of this delay is to allow additional time to work through details of the Resource Capacity Accreditation project as well as a prompt/seasonal market design[314], which are planned to be implemented with FCA19.

[312] See an overview of ISO's *Key Projects*, available at https://www.iso-ne.com/committees/key-projects

[313] See FERC's letter accepting the ISO's filing *Docket No. ER24-1245-000* (April 12, 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf

[314] See Section 9.2.3

FERC accepted the ISO's proposal in May 2024.[315]

9.1.3 Day-Ahead Ancillary Services Initiative

FERC accepts March 2025 implementation

The Day-Ahead Ancillary Services Initiative (DASI) sets out to procure and transparently price specific ancillary services needed for system reliability. Currently, there is no day-ahead reserves market in ISO-NE. The ISO added four new reserve products that would be co-optimized with energy and priced in the day-ahead market.[316] These day-ahead reserve products are not forward sales of reserves that settle against real-time reserve prices; instead, they have an energy call-option settlement structure, where the Day-Ahead Ancillary Services are settled like a call option based on a pre-determined strike price and the actual real-time Hub LMP. The ISO also proposed to retire the Forward Reserve Market at the time of DASI implementation.

The ISO submitted proposed tariff revisions for DASI to FERC in October 2023, and FERC accepted those revisions, establishing an effective date of February 28, 2025.

9.2 Major Design or Rule Changes in Development or Implementation for Future Years

The following market design or rule changes are either (i) currently being assessed or are in the design phase or (ii) have been completed and the planned implementation date is in the future.

9.2.1 Fuel Price Adjustment Modifications

FERC accepts ISO proposal

In July 2024, the ISO filed proposed changes to the Fuel Price Adjustment (FPA) process to allow Market Participants to include a MW value and up to two fuel prices in a FPA request. These changes will allow a Market Participant to reflect up to two fuel prices in its resource's cost-based Reference Levels. This proposal is a response to FERC's Show Cause Order[317] related to upward mitigation.

FERC accepted the ISO's proposal in November 2024, establishing an effective date to be established no less than 15 days before implementation.[318]

9.2.2 FERC Order 2222, Distributed Energy Resources

FERC issued orders in 2024 on the ISO's further compliance filing

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[315] See FERC's letter accepting the ISO's filing *Docket No. ER24-1710-000* (May 20, 2024), available at https://www.iso-ne.com/static-assets/documents/100011/er24-1710-000.pdf

[316] Three of these products mirror the three real-time reserve products: TMSR, TMNSR, and TMOR; the fourth product is called Energy Imbalance Reserve, which is procured to essentially help fill any potential "energy gap" between forecasted load and cleared day-ahead physical supply.

[317] See *Order Granting Cost Recovery Request in Part and Denying in Part and Establishing a Show Cause Proceeding* (May 5, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/06/el23-62-000.pdf

[318] See *Order Accepting Tariff Revisions, Terminating Show Cause Proceeding and Directing Informational Filing* (November 21, 2024), available at https://www.iso-ne.com/static-assets/documents/100017/er24-2584_el23-62_order_accept_revisions_terminate_show_cause_direct_info_filing.pdf

On September 17, 2020, FERC issued Order 2222, which found that existing ISO/RTO market rules were unjust and unreasonable because they contained barriers to the participation of distributed energy resources aggregations (DERAs).[319] The purpose of Order 2222 is to remove these barriers and allow DERAs to provide all services that they are technically capable of providing. Specifically, the order outlined 11 directives for ISOs/RTOs to follow, including allowing participation of DERAs in the energy, ancillary services, and capacity markets, allowing DER aggregators to register DERAs under one or more participation models[320], and establishing a minimum size requirement for DERAs of no more than 100 kW.

During 2020 and 2021, the ISO worked with stakeholders to develop the tariff revisions necessary to come into compliance with Order 2222. The ISO's proposed tariff changes were brought through the complete stakeholder process. At its January 2022 meeting, the NEPOOL Participant's Committee voted to support the proposal (71.10% in favor).

On February 2, 2022, the ISO, joined by NEPOOL and the PTO AC, filed a compliance proposal for Order 2222.[321] The proposal creates two new participation models for the energy and ancillary services market (called Demand Response DERA and Settlement Only DERA) and leverages five existing models to accommodate the physical and operational characteristics of DERAs. The proposal includes many other changes to comply with the order, including introducing a new participation model for the FCM (called a Distributed Energy Capacity Resource), setting a minimum size of 100 kW for DERAs, specifying locational requirements, and establishing metering and telemetry rules.

The ISO requested two effective dates: 1) November 1, 2022, for FCM-related revisions, which would be in time for the FCA 18 qualification process, and 2) November 1, 2026, for changes related to the energy and ancillary services market.

In March 2023, FERC issued an order accepting in part and rejecting in part the ISO's compliance filing, subject to further compliance filings. In its order, the FERC found that the ISO's compliance filing satisfied six of the eleven aforementioned directives in Order 2222 but only partially satisfied the remaining five directives, which include issues related to storage participation models, information and data requirements, metering and telemetry requirements, and other issues.[322] FERC established 30-day, 60-day, and 180-day compliance filing requirements for addressing these deficiencies.

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[319] A Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction. See FERC's *FERC Order No. 2222: Fact Sheet* webpage (last updated September 28, 2020), https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

[320] A "participation model" refers to rules created for a specific type of resource that has unique physical and operational characteristics. For example, a generator is a type of participation model in ISO-NE. See *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets; Docket No. ER22-___-000* (February 2, 2022), p. 5, footnote 7, available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf

[321] See ISO New England Inc., *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets, FERC filing, Docket No. ER22-983-000* (February 2, 2022),available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf

[322] For a summary of the FERC's order on compliance filing, see memorandum *Overview of the FERC's Order on New England's 2/2/22 Order 2222 Compliance Filing* (March 3, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/03/a05_2023_03_07-09_order_2222_nepool_counsel_memo.pdf.

The ISO submitted filings in March 2023,[323] May 2023,[324] and August 2023[325] to provide additional information needed by FERC in its March 2023 order. In October 2023, FERC issued an order accepting the ISO's 30-day and 180-day compliance filings, and established a new effective date of March 1, 2024, for rules allowing DECRs to participate in the FCM.[326] On November 2, 2023, FERC issued an order accepting the ISO's 60-day compliance filing on all but one of the compliance items.[327] FERC established a compliance deadline of January 31, 2024, for the ISO to file changes to allow the DER Aggregator to be the entity responsible for providing any required metering information, and accepted the ISO's compliance filing on the matter on November 19, 2024.[328]

9.2.3 Capacity Auction Reforms (CAR) in the Forward Capacity Market (FCM)

Stakeholder discussions to continue through 2026

In 2024, the ISO began the Capacity Auction Reforms (CAR) project, which makes a variety of significant changes to the FCM. First, CAR aims to shift the FCM from a three-year forward market to a prompt market, in which the auction is run closer to the delivery period. Second, CAR will change the FCM from being an annual auction to a seasonal auction. Finally, CAR will continue the resource capacity accreditation (RCA) work begun in 2022, but in the context of a prompt and seasonal market structure. RCA is intended to accredit capacity to resource classes in a way that will better reflect their contributions to resource adequacy.

CAR stakeholder discussions are expected to be ongoing during 2025 and 2026, with stakeholder voting tentatively scheduled in Q4 2026.

9.3 Additional Notable Studies

The following subsection provides an overview of additional notable studies that are not part of any planned market design or implementation work.

9.3.1 Economic Planning for the Clean Energy Transition (EPCET) study

The EPCET study[329] highlights many of the potential challenges of the clean energy transition and identifies trends that the region should consider to ensure power system reliability,

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[323] See *ISO New England Inc., Thirty-Day Informational and Compliance Filing Regarding Order No. 2222 Compliance, Docket No. ER22-983-____* (March 31, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/03/er22-983_iso-ne_30-day_comp_filing.pdf

[324] See *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff In Further Compliance with Order No. 2222 and Request for Extension of Compliance Deadline; ISO New England Inc., Docket No. ER22- 983-____* (May 9, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/05/er22-983-further_order_no_2222_compliance.pdf

[325] See *ISO New England Inc., One Hundred Eighty-Day Informational and Compliance Filing Regarding Order No. 2222 Compliance, Docket No. ER22-983-____* (August 28, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/08/order_2222_compliance_filing.pdf

[326] See FERC's *Order Accepting Order No. 2222 Informational Filing and 180 Day Compliance Filing, Docket No. ER-ER22-984-005* (October 25, 2003), available at https://www.iso-ne.com/static-assets/documents/100004/er22-984-005_and_003.pdf

[327] See *Order on Compliance Filing Docket No. ER22-983-004* (November 2, 2023), available at https://www.iso-ne.com/static-assets/documents/100005/er22-983-004.pdf

[328] See *Letter Order Accepting DER Aggregations Docket No. ER22-983-009* (November 19, 2024), available at https://www.iso-ne.com/static-assets/documents/100017/er22-983-009_letter_order_accept_der_aggregations.pdf

[329] See *Economic Planning for the Clean Energy Transition* (October 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf

progress toward state decarbonization goals, and informed decision-making about efficient spending and investment. This study considers a variety of future scenarios, looking out as far as 2050, and examines the effects of different future resource mixes and weather conditions on energy and resource adequacy, carbon emissions, system reliability, and existing market designs. The key findings highlight the tradeoffs that exist amongst reliability, economic efficiency, and carbon neutrality.

ISO-NE published the EPCET study in October 2024.

9.3.2 Assessing Operational Impacts of Extreme Weather Events and the Probabilistic Energy Assessment Tool (PEAT)

The Operational Impacts of Extreme Weather Events project focuses on assessing New England's energy-security risks under extreme weather conditions.[330] In 2022 and 2023, the ISO partnered with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT), a modeling tool designed to evaluate operational energy-security risks associated with extreme weather. In 2025, the ISO is using PEAT results to work with regional stakeholders to establish a Regional Energy Shortfall Threshold (REST) that defines an acceptable level of energy-adequacy-driven reliability risk. Depending on the outcomes, further analysis could assess the need for regional solutions such as new market designs, infrastructure investments, or enhanced consumer responsiveness.

By conducting comprehensive, probabilistic assessments—including consideration of low-probability, high-impact risks—the ISO and stakeholders are preparing the region's evolving power system for future challenges. This project is part of the ISO's broader effort to enhance the reliability of the grid and the competitiveness of New England's wholesale electricity markets.

[330] See *ISO's Operational Impacts of Extreme Weather Events Key Project* information page, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
BTM	behind-the-meter
Btu	British thermal unit
C4	market concentration of the four largest competitors
CASPR	Competitive Auctions with Sponsored Policy Resources
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation
DARD	dispatchable asset related demand
DDBT	dynamic de-list bid threshold

Acronyms and Abbreviations	Description
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EGEL	Electricity Generator Emissions Limits (program)
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GW	gigawatt
GW-month	gigawatt-month
GWh	gigawatt-hour
GWSA	Global Warming Solutions Act
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor

Acronyms and Abbreviations	Description
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOC	lost opportunity cost
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone

Acronyms and Abbreviations	Description
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PPR	pay-for-performance penalty rate
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PTO	Participating Transmission Owners
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter
RA	reconfiguration auction
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative

Acronyms and Abbreviations	Description
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
UTC	up-to-congestion
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate