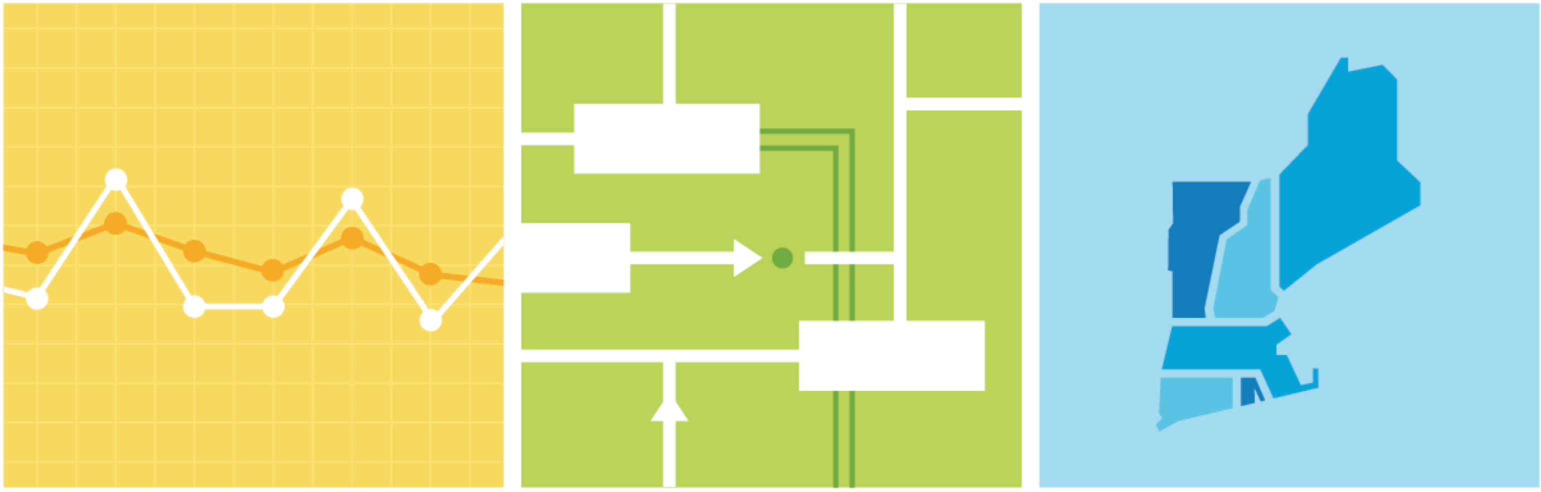
Fall 2025
Quarterly Markets Report

By ISO New England’s Internal Market Monitor

FEBRUARY 4, 2026



Preface/Disclaimer

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets 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.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A.*

All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

[2] Available at http://www.theice.com.

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Fall 2025 (September 1, 2025 through November 30, 2025).

Wholesale Costs: In Fall 2025, the total estimated wholesale market cost of electricity was $1.87 billion, up 25% from $1.47 billion in Fall 2024. Energy costs comprised 83% of wholesale costs and totaled $1.56 billion, a 58% increase from Fall 2024. Higher natural gas prices (up 58% from Fall 2024) were the main driver of higher energy market costs compared to Fall 2024. Emissions costs were also up 10% year-over-year.

Energy market costs also include Forecast Energy Requirement (FER) credits, which are payments made to physical supply resources (generators, demand response resources, and imports) with day-ahead energy awards as part of the Day-Ahead Ancillary Services (DA A/S) market (launched March 1, 2025). These costs totaled $167 million in Fall 2025 and were paid to generators and imports.

Capacity costs totaled $266 million, representing 14% of total wholesale market costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was nearly the same as the prior year ($2.61/kw-month in CCP 15, June 2024 – May 2025). Despite the comparable clearing price, total costs were 26% lower in Fall 2025 than in Fall 2024, due to lower cleared capacity and less upward price separation in the import-constrained Southeast New England capacity zone.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $44.64 and $45.22/MWh, respectively. These were 24-27% higher than Fall 2024 prices, on average.

- Average natural gas prices increased by 58%, which was the primary driver of higher energy prices. Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance prices also increased 10% from Fall 2024, reaching $24.24 per short ton of CO_2 in Fall 2025.
- The FER price paid through the DA A/S market to day-ahead cleared generation that meets the forecast energy requirement averaged $5.49/MWh, up from $3.07/MWh in Summer 2025. Adding the FER price to the day-ahead LMP resulted in day-ahead prices that were $4.91/MWh higher than the real-time LMP, on average.
- Hourly loads were up 1.7% relative to Fall 2024. This increase was primarily driven by colder conditions in November, which raised heating-related demand.

System Events: On Sunday, November 23, 2025, ISO New England experienced capacity scarcity conditions (CSC) which lasted for thirty minutes, from 17:50 to 18:20. It was the first CSC event to occur without extreme weather or high loads; the expected high temperature in New England was 41°F and the expected peak load was 15,700 MW. At the beginning of the operating day, operators expected normal conditions, with forecasted supply margins of nearly 1,000 MW despite nearly 5,000 MW of generation out-of-service. During the peak load hour (Hour Ending 18), loads were slightly above forecast (~200 MW higher) and the reserve margins were lower than expected. At 17:38, a large thermal generator tripped offline followed by some smaller resources, resulting in a 900 MW generation loss. Following the trip, reserves were activated to cover the lost generation and New England accessed shared reserves with neighboring regions. System operators manually dispatched 21 resources (mostly Demand Response Resources) to meet energy requirements and increase reserves. Despite these actions, at 17:50, ISO New England entered a ten-minute and thirty-minute reserve deficiency, resulting in the CSC event. The ten-minute and thirty-minute reserve constraint penalty factors were in place for 20 minutes and 30 minutes, respectively. Total ten-minute reserves were 66 MW (or 4%) below the reserve requirement for all 20 minutes. Total thirty-minute reserves reached a 255 MW (or 11%) deficiency. The CSC event ended as evening load decreased, imports increased, and a collection of fast-start units finished powering down, which allowed them to provide thirty-minute operating reserves from an offline state.

Pay-for-Performance (PfP) payments from the 30-minute event totaled $32.3 million. While payments were small relative to the June 24, 2025 PfP event, payments per shortage interval were high relative to past events due to the $9,337/MWh performance payment rate that became effective on June 1, 2025. With lower load and reserve requirements compared to prior events, the balancing ratio averaged just 70%. As a result, resources that produced more than 70% of their capacity supply obligation received net PfP payments. No resources reached monthly or annual stop-loss limits. Notably, there were over 1,700 MW of real-time scheduled exports during the event. While the event was short in duration, assessment of PfP charges to exports would have reduced export demand and would therefore likely have reduced reserve shortfalls.[3]

Supply mix: There were notable differences in the supply mix in Fall 2025 compared to Fall 2024. In Fall 2025, New England became a net exporter of energy to neighboring control areas, likely for the first time in at least 20 years, with an average flow of 33 MW per hour out of New England. Increased nuclear and wind generation helped to fill this gap. The share of supply from nuclear generation increased from 18% in Fall 2024 to 25% in Fall 2025 while average hourly wind generation increased by 150 MW, accounting for 5% of supply in Fall 2025 compared to 4% in Fall 2024.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $7.6 million in Fall 2025, down slightly from $8.4 million in Fall 2024. Economic uplift continued to comprise the largest share of NCPC, totaling $6.5 million. Performance audit uplift is common during the fall, and audit payments were similar to those in prior fall seasons ($1 million). Special constraint resources received the remainder of NCPC ($0.1 million) during commitments to meet distribution needs.

Day-Ahead Ancillary Services[4]: Net Day-ahead Ancillary Services (DA A/S) payments, which account for credits and closeout charges, decreased between Summer 2025 ($57.4 million) and Fall 2025 ($34.1 million), but remained steady at 2% of total energy and ancillary services (E&AS) costs given that energy costs also decreased.

While not made to DA A/S awards, the forecast energy requirement (FER) credit is an additional payment that was introduced as part of the market design reforms associated with DA A/S market. This credit is paid to physical supply resources (i.e., generators, demand response resources, and imports) with day-ahead energy awards. In Fall 2025, the FER credit totaled $166.9 million, representing 10% of total E&AS costs.

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[3] See the IMM's recommendation on PfP treatment of exports in our *2024 Annual Markets Report*, available at https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf.

[4] On March 1, 2025, ISO New England launched a new suite of day-ahead ancillary services (DA A/S) designed to procure operating reserves and ensure sufficient supply to meet the ISO's load forecast through market mechanisms. The new products include day-ahead ten-minute spinning reserve (DA TMSR), day-ahead ten-minute non-spinning reserve (DA TMNSR), day-ahead thirty-minute reserves (DA TMOR), and Energy Imbalance Reserve (EIR).

The IMM performed market simulations to better understand the incremental impact of DA A/S design on market outcomes relative to the day-ahead market design that was in place prior to March 1, 2025. Based on these simulations, we estimate that the DA A/S market has resulted in an increase of $400 million (8.2%) in total market costs over its first nine months. We estimate that nearly three quarters of this incremental cost increase come from higher day-ahead energy market payments, with the remainder due to net payments to resources with cleared DA A/S awards.

Real-time Reserves: Overall, there were ample reserves to satisfy the reserve requirements throughout Fall 2025, with the exception of the capacity scarcity condition on November 23. That event drove half of the real-time reserve payments in Fall 2025 ($4.6 million), which were up from Fall 2024 ($0.6 million).

Regulation: Total regulation market payments were $4.02 million during Fall 2025, down 6% from $4.3 million in Fall 2024. The decrease in payments resulted primarily from lower capacity prices (down 21%). Capacity prices decreased due to a decline in regulation offer prices, as lower cost alternative technology regulation resources (primarily batteries) continue to make up a larger share of the regulation mix.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Fall 2025 was 103, indicating that the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier, on average. There was at least one pivotal supplier present in the real-time market for 39% of five-minute pricing intervals in Fall 2025, which was higher than the Fall 2024 frequency due to lower margins that resulted from decreased availability of pumped-storage generators. Higher loads and less interchange also contributed to the lower RSI and increased intervals with pivotal suppliers.

Of about 28,000 eligible asset hours that failed structural tests, there were only 80 asset hours of mitigation in Fall 2025 (0.28% of asset hours mitigated). Real-time manual dispatch energy (MDE) mitigation represented about two-thirds of that mitigation in Fall 2025 with 55 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing offers from resources being manually dispatched by the ISO to be 10% higher than reference levels.

Financial Transmission Rights (FTRs): Day-ahead congestion revenue amounted to $8.2 million in Fall 2025, down from $9.9 million in Fall 2024. Congestion revenue was similar to Summer 2025 given similar system conditions and day-ahead LMPs. Positive target allocations totaled $8.8 million. Real-time congestion revenue ($0.6 million) and negative target allocations ($1.1 million) more than compensated for the deficit between day-ahead congestion revenue and positive target allocations. Consequently, FTRs were fully funded throughout the fall.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 2-1 below.

Table 2-1: High-Level Market Statistics

Market Statistics	Fall 2025	Summer 2025	Fall 2025 vs Summer 2025 (% Change)	Fall 2024	Fall 2025 vs Fall 2024 (% Change)
Real-Time Load (GWh)	26,724	32,533	-18%	26,251	2%
Peak Real-Time Load (MW)	17,234	26,597	-35%	17,059	1%
Average Day-Ahead Hub LMP ($/MWh)	$44.64	$53.31	-16%	$35.91	24%
Average Forecast Energy Requirement Price ($/MWh)	$5.49	$3.07	$2.66	-	-
Average Real-Time Hub LMP ($/MWh)	$45.22	$49.65	-9%	$35.72	27%
Average Natural Gas Price ($/MMBtu)	$3.07	$3.29	-7%	$1.95	58%
Average No. 6 Oil Price ($/MMBtu)	$14.95	$15.18	-2%	$13.91	7%
Average RGGI Carbon Price ($/Short Ton CO_2)	$24.24	$21.65	12%	$21.97	10%

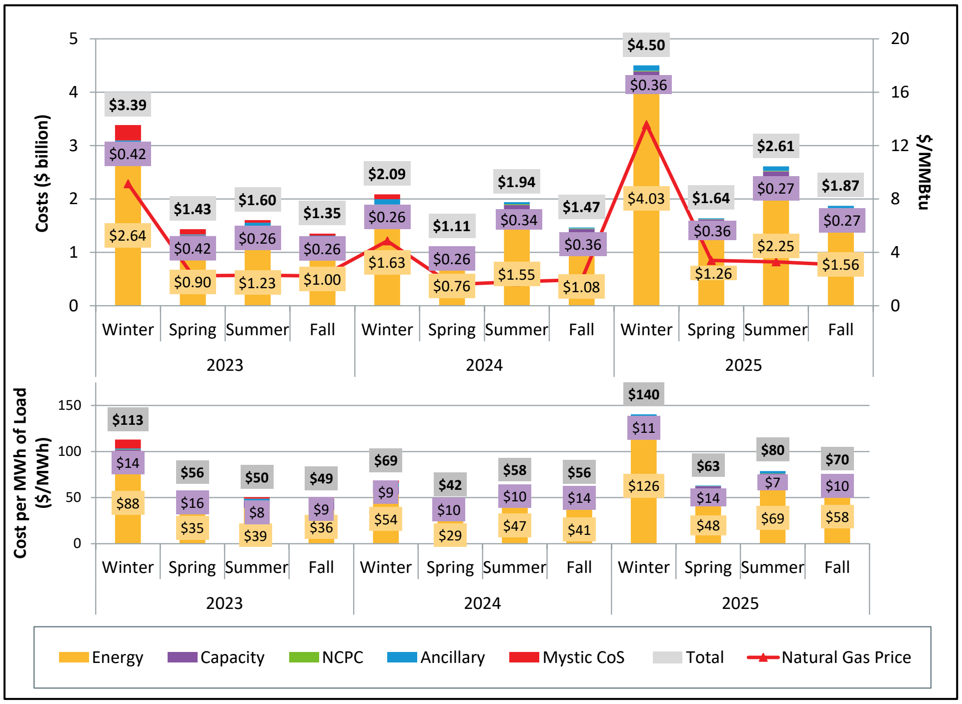
Key observations from the table above:

- Loads averaged 12,207 MW in Fall 2025, a 1.7% increase from Fall 2024, primarily due colder temperatures in November. Behind-the-meter (BTM) solar output grew by 12%, from 559 MW in Fall 2024 to 624 MW in Fall 2025.
- Day-ahead LMPs averaged $44.64/MWh, while the Forecast Energy Requirement Price averaged $5.49/MWh. This price is paid to day-ahead cleared generation that meets the forecasted energy requirement. Together, these prices led to a $4.91/MWh premium over the real-time LMP, on average.
- Average natural gas prices increased by 58%, which was the primary driver of the increase in energy prices. Natural gas basin prices were higher, leading to the increase in natural gas prices in New England.
- Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance prices increased by 10% compared with Fall 2024. However, RGGI's contribution to the cost of gas-fired generation fell from 40% to 32% because of the larger year-over-year increase in natural gas prices.

2.1 Wholesale Cost of Electricity

The estimated wholesale cost of electricity (in billions of dollars), categorized by cost component, is shown by season in the upper panel of Figure 2-1 below. It also shows the average natural gas price (in $/MMBtu) as energy market payments in New England tend to be correlated with the price of natural gas in the region.[5] The bottom panel in Figure 2-1 depicts the quarterly wholesale cost per megawatt hour of real-time load for Winter 2023 through Fall 2025.

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Fall 2025, the total estimated wholesale cost of electricity was $1.87 billion (or $70/MWh of load), a 28% increase compared to $1.47 billion in Fall 2024 and a 28% decrease compared to $2.61 billion in Summer 2025. The increase from Fall 2024 resulted from higher energy costs.

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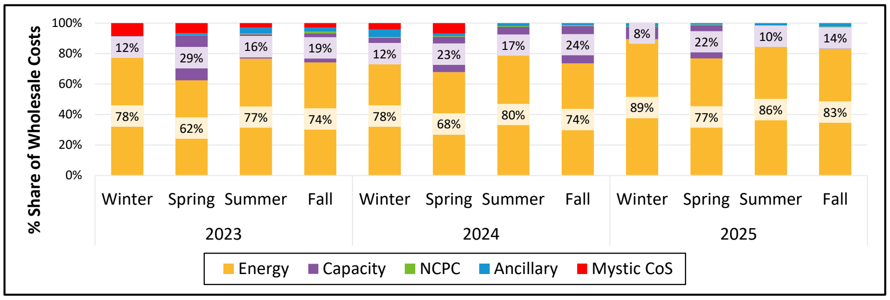
[5] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, Maritimes and Northeast, and Tennessee gas pipeline Z6-200L. 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.

The share of each wholesale cost component since Winter 2023 is shown in Figure 2-2 below.

Figure 2-2: Percentage Share of Wholesale Costs



Energy costs comprised 83% of wholesale costs and totaled $1.56 billion ($58/MWh) in Fall 2025, 58% higher than Fall 2024 costs. Higher natural gas costs led to the increase in energy costs. Natural gas prices in New England increased in line with prices in natural gas supply basins. Average natural gas prices were up 58% and emissions costs were up 10% year-over year.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Fall 2025, capacity payments totaled $266 million ($10/MWh), representing 14% of total costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was similar to the prior year (CCP 15, June 2024 – May 2025). Costs were lower in Fall 2025 due to a decrease in cleared capacity in FCA 16 and less upward price separation in the import-constrained Southeast New England capacity zone. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

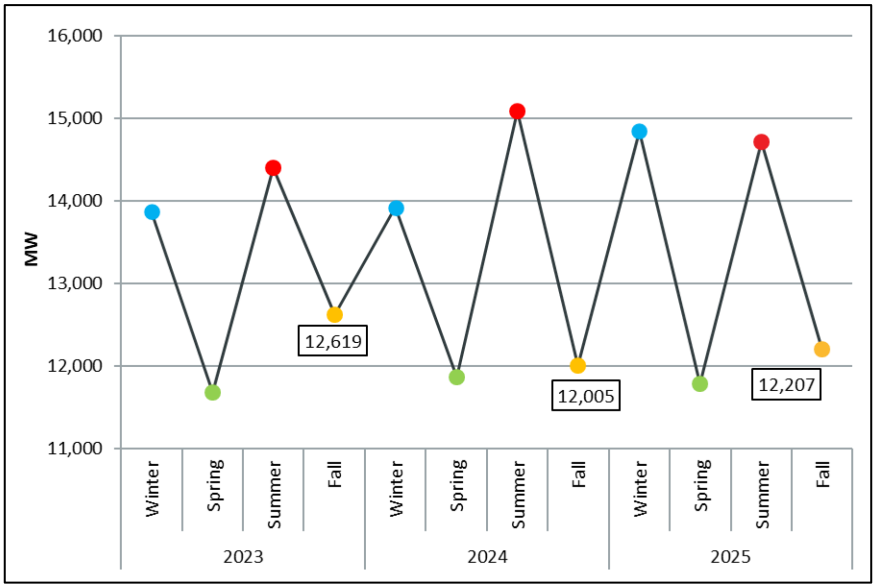
At $7.6 million ($0.29/MWh), Fall 2025 Net Commitment Period Compensation (NCPC) costs decreased by 9% compared to Fall 2024 due to a decrease in economic payments. NCPC costs represented 0.5% of total energy payments in Fall 2025, which was similar to recent seasons.

Ancillary service costs, which include payments for day-ahead reserves, real-time reserves and regulation, totaled $42.7 million ($1.60/MWh) in Fall 2025 representing 2% of total wholesale costs. Ancillary service costs increased by 111% compared to Fall 2024 costs, as DA A/S costs this fall exceeded forward reserve payments during the prior fall. Ancillary costs associated with the DA A/S market totaled $34.1 million this fall.

2.2 Load

This section analyzes quarterly system load and demand conditions, comparing Fall 2025 load against historical baselines.[6] Figure 2-3 illustrates the average hourly distribution by quarter. Seasonal categories are differentiated by color: winter (blue), spring (green), summer (red), and fall (yellow).

Figure 2-3: Average Hourly Load by Quarter



Hourly loads averaged 12,207 MW in Fall 2025, a 1.7% increase relative to Fall 2024. This increase was primarily driven by colder conditions in November, which raised heating-related demand. Over the same period, behind-the-meter (BTM) solar capacity expanded, with average output rising 12%, from 559 MW in Fall 2024 to 624 MW in Fall 2025. However, solar irradiance declined by approximately 4%, particularly in November, reducing potential solar production during daylight hours. As a result, despite increased BTM solar capacity, lower irradiance likely offset a portion of the expected output gains. The observed increase in net system load therefore reflects the combined effects of higher weather-driven demand and reduced effective solar production.

Load and Temperature

Temperature significantly influences load patterns, with demand rising during periods of extreme heat or cold due to increased cooling and heating needs. Figure 2-4 demonstrates this dependency by plotting average monthly load against cumulative degree days. The top panel shows the

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[6] In this section, the term "load" typically refers to net energy for load (NEL), while "demand" typically refers to end-use demand. NEL is generation needed to meet end-use demand (NEL – Losses = Metered Load). NEL is calculated as Generation + Settlement-only Generation – Asset-Related Demand + Price-Responsive Demand + Net Interchange (Imports – Exports).

relationship with cooling degree days (CDDs), and the bottom panel with heating degree days (HDDs), providing insight into how weather conditions shape energy consumption.[7]

Figure 2-4: Monthly Average Load and Monthly Total Degree Days

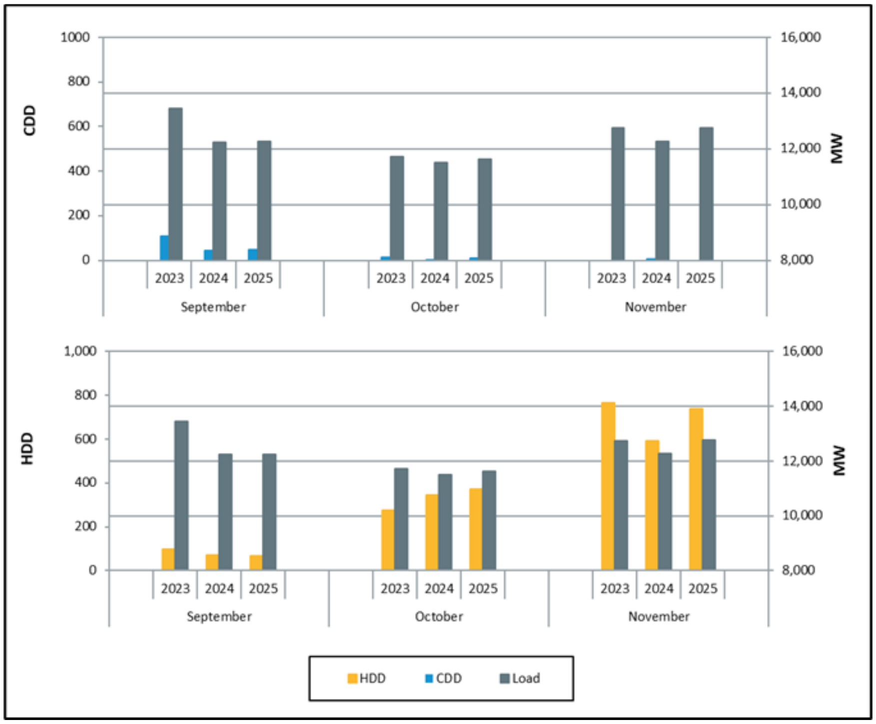

Figure 2-4 illustrates that average monthly load in Fall 2025 increased slightly compared to Fall 2024. This rise coincided with a significant increase in heating degree days (HDD) during November, which climbed from 591 to 740. Consistent with this trend, average temperatures in September and October remained unchanged, while average November temperatures declined from 47°F in Fall 2024 to 44°F in Fall 2025. These weather-driven changes contributed to higher heating demand and higher load.

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[7] Cooling degree days (CDDs) measure how warm average daily temperature is relative to 65°F and are an indicator of electricity demand for cooling. CDDs are calculated as the number of degrees (°F) that the average of a given day's high and low temperatures are above 65°F. Heating degree days (HDD) measure how cold the average of a day's high and low temperatures are relative to 65°F and are an indicator of electricity demand for heating. HDDs are calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day has a high temperature of 80°F and a low temperature of 60°F, the average of the high and low temperature is 70°F and the day has 5 CDDs.

Peak Load and Load Duration Curves

New England's system load over the past three fall seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads.[8]

Figure 2-5: Fall Load Duration Curves

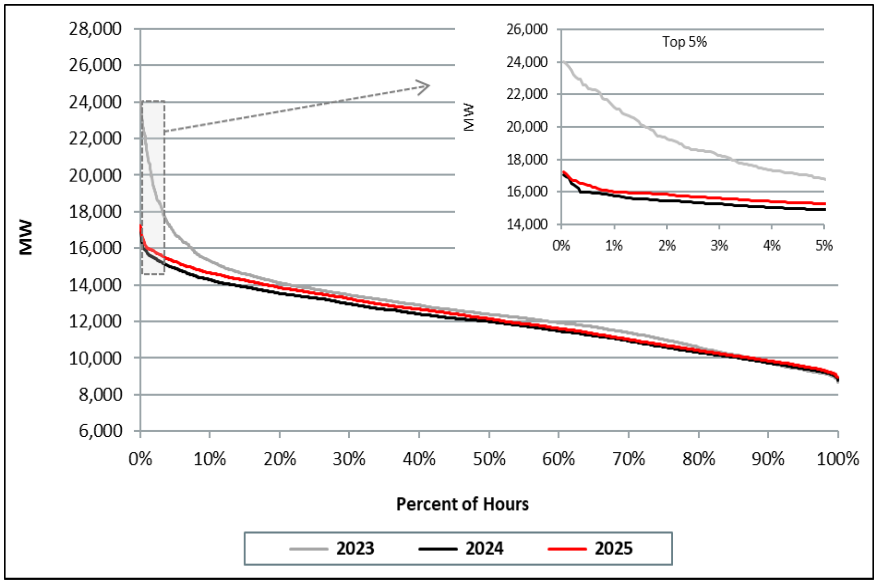

Figure 2-5 shows that Fall 2025 loads were higher than those in Fall 2024, though still below Fall 2023 levels, which were driven by abnormal heatwave conditions. Peak load for Fall 2025 reached 17,226 MW compared to 17,055 MW in Fall 2024. This increase reflects colder weather conditions in November 2025 which drove higher heating demand.

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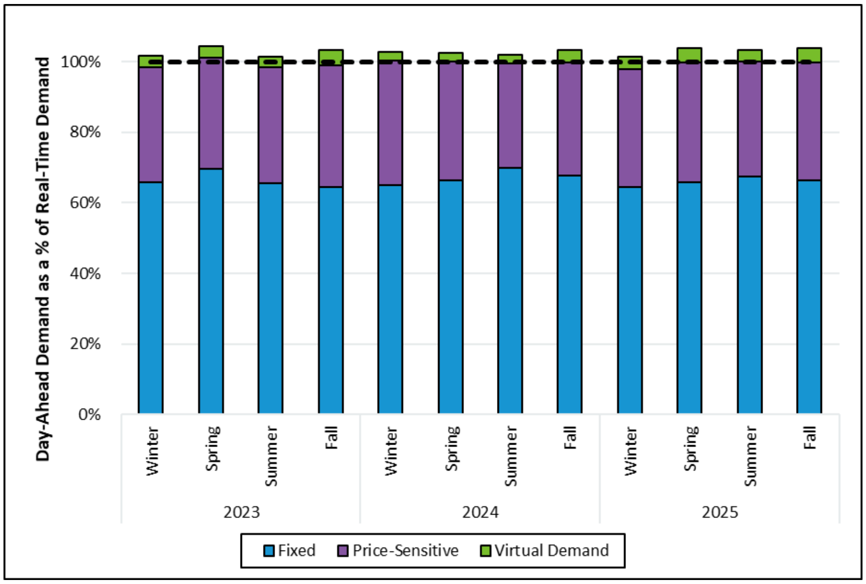
[8] A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher.

Load Clearing in the Day-Ahead Market

The average amount of load that participants cleared in the day-ahead market as a share of actual real-time load over the past two years is shown in Figure 2-6 below.

Figure 2-6: Day-Ahead Cleared Demand as Percent of Real-Time Demand, by Quarter



Participants cleared 104% of real-time demand in the day-ahead market during Fall 2025, down from 103% from Fall 2024. Fixed demand bids accounted for 66% of real-time load, while price-sensitive demand bids represented 33%. These shares have remained relatively stable compared to prior quarters. Most price-sensitive demand bids continued to be submitted well above expected day-ahead LMPs, resulting in minimal impact on market outcomes. Virtual demand represented 4% of real-time load, up from 3% from Fall 2024.[9]

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[9] For more information on virtual transactions, see section 3.3.

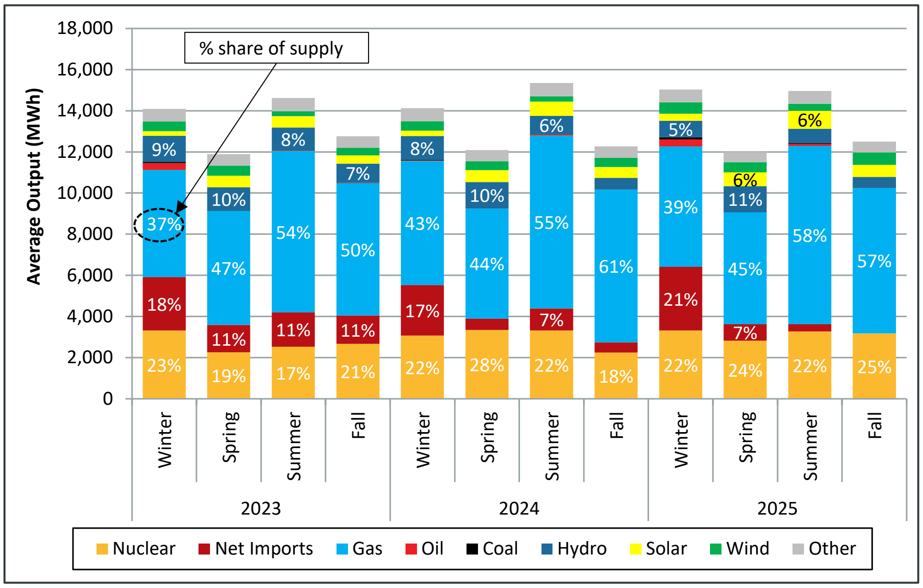
2.3 Supply

This subsection summarizes actual energy production by fuel type, and flows of power between New England and its neighboring control areas.

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for understanding the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2023 through Fall 2025 is illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the share of generation from each fuel type.[10]

Figure 2-7: Share of Electricity Generation by Fuel Type



There were notable differences in the fuel mix in Fall 2025 compared with previous fall seasons. New England was a net exporter of power for the first time in at least 20 years as discussed more in the next section. Nuclear generation increased from 18% to 25% due to fewer outages this fall season. Wind generation increased from 4% to 5% of overall supply, largely driven by additional offshore wind capacity. Natural gas-fired generation continued to provide the largest share of energy in Fall 2025, supplying 57% of the region's energy on average.

2.3.2 Imports and Exports

New England was a net exporter of energy to the neighboring control areas in Canada and New York. This was likely the first time New England was a net exporter of energy in at least 20 years. Net interchange decreased at every interface besides New Brunswick. On average, the net flow of energy out of New England was 33 MW per hour. The average hourly import, export and net

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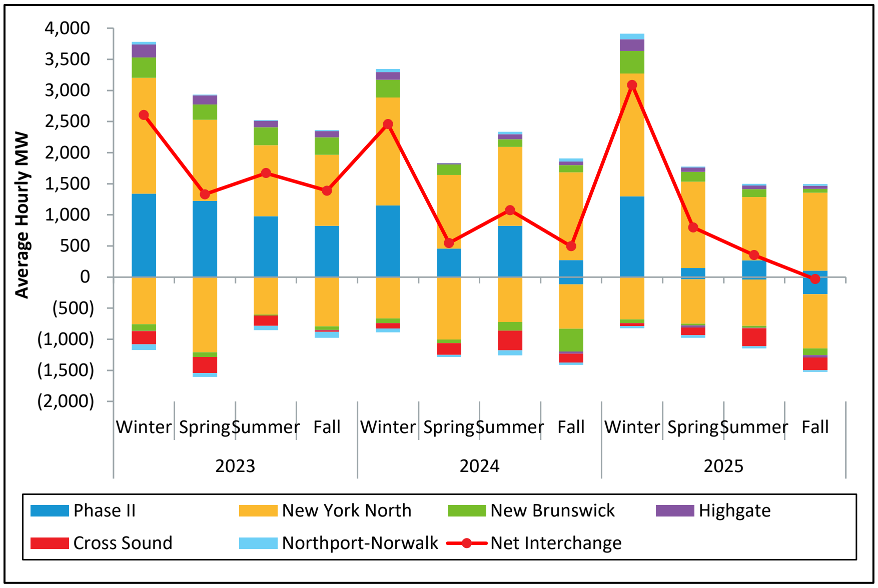
[10] Electricity generation in Section 2.3.1 equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood.

interchange power volumes by external interface for the last 12 seasons are shown in Figure 2-8 below.

Figure 2-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



Canadian Interfaces

New England exported 207 MW per hour over the three Canadian interfaces during Fall 2025. Historically, New England has been a net importer of energy from all Canadian interfaces with net interchange averaging 1,009 MW per hour from Winter 2023 to Summer 2025.

At the Phase II interface, which connects New England to Quebec, New England was a net exporter of energy, averaging 172 MW of exports per hour. In Quebec, normally abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, drier weather over the last few years reduced the excess energy available in Quebec and limited exports to New England.[11] At Highgate, the other interface connecting New England to Quebec, New England imported an average of 11 MW per hour, down from 21 MW per hour in Fall 2024.

In Fall 2025, New England exported an average of 45 MW per hour to New Brunswick, down from 249 MW per hour exported in Fall 2024. While New England is typically a net importer of electricity from New Brunswick, a large generator in New Brunswick was out of service for the second consecutive fall.[12] These outages have resulted in more exports from New England to New Brunswick.

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[11] For more information on the reduction in exports, see Hydro-Québec's *Quarterly Bulletin, Third Quarter 2025*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2025-3.pdf .

[12] For more information on the generator outage see *Point Lepreau Nuclear Generating Station Returns to Operations*, available at https://www.nbpower.com/en/about-us/news-media-centre/news/2025/point-lepreau-nuclear-generating-station-returns-to-operation/

New York Interfaces

At the New York interfaces, higher energy prices in New York led to average net interchange decreasing by nearly 400 MW per hour relative to Fall 2024. New England remained a net importer of energy from New York, averaging 174 MW per hour in Fall 2025. At the New York North interface, imports decreased despite similar day-ahead and real-time price outcomes between New York and New England. Participants may be willing to flow energy uneconomically at the interface if they have out-of-market contracts (such as a Power Purchase Agreement) requiring the flow of energy even if spot market prices do not align with the direction of the transaction.

New England exports energy to Long Island, an area that is often import-constrained compared to the rest of the New York control area. In Fall 2025, New England exported an average of 207 MW and 1 MW to Long Island over the Cross Sound Cable and Northport-Norwalk interfaces, respectfully. At the Cross Sound Cable interface, average New York prices were $2.24/MWh higher than in New England; New England prices were higher in Fall 2024. During Fall 2025, the Northport-Norwalk interface was frequently limited to 25 MW due to transmission work, limiting the total cleared transactions at the interface.

2.4 Market Performance on November 23, 2025

This section examines the performance of the New England electricity markets during the November 23, 2025 Capacity Scarcity Conditions (CSC).[13]

2.4.1 Event Overview

All prior CSC events in New England occurred during the summer or winter months, periods when extreme temperatures can drive high loads and tight system conditions in New England. Tight system conditions are typically exacerbated by a combination of generator trips, load forecast error or reductions in net interchange. The November 23 (Sunday), 2025 event was the first CSC event to occur without extreme weather or high loads. Additionally, there were no large load forecast errors or reductions in net interchange.

On November 23, 2025, normal conditions were anticipated during the morning. Operators forecasted supply margins of nearly 1,000 MW despite nearly 5,000 MW of generation out-of-service. The average New England temperature was expected to reach 41°F, and the morning load forecast expected peak loads to reach just over 15,700 MW.[14] During the middle of the operating day, actual temperatures were up to 2°F colder than forecasted and behind-the-meter solar generation was lower than expected. These factors contributed to actual loads being up to 600 MW higher than the load forecast.

During the peak load hour (Hour Ending 18), loads were slightly above forecast (~200 MW higher) and the reserve margins were lower than expected. Total ten-minute and thirty-minute reserve margins were 234 MW and 283 MW, respectively. At 17:38, a large thermal generator tripped offline followed by some smaller resources, resulting in a 900 MW generation loss. Following the trip, reserves were activated to cover the lost generation and New England accessed shared reserves with neighboring regions. System operators manually dispatched 21 generators (mostly Demand Response) to meet energy requirements and increase reserves. At 17:50, ISO New England entered a ten-minute and thirty-minute reserve deficiency, resulting in the CSC event. During the event, real-time Hub LMPs reached $2,665.55/MWh and the reserve deficiency lasted for 30 minutes, or six 5-minute intervals. The ten-minute and thirty-minute reserve constraint penalty factors were in place for 20 minutes and 30 minutes, respectively. Total ten-minute reserves were 66 MW (or 4%) below the reserve requirement for all 20 minutes. Total thirty-minute reserves reached a 255 MW (or 11%) deficiency. The capacity shortage conditions ended as evening load decreased, imports increased, and a collection of fast-start units finished powering down, which allowed them to provide thirty-minute operating reserves from an offline state.

Pay-for-Performance (PfP) payments totaled $32.3 million. While payments were small relative to the June 24, 2025 PfP event, payments per shortage interval were high relative to past events due to the $9,337/MWh performance payment rate that became effective on June 1, 2025. With lower load and reserve requirements compared to prior events, the balancing ratio averaged just 70%, indicating that the system needed 70% of all contracted capacity to meet load and reserve requirements. Resources that produced more than 70% of their CSO therefore received net PfP payments. No resources reached monthly or annual stop-loss limits. Hydro and fast-start resources performed well due to their operational flexibility. Uncontracted imports provided over 1,400 MW,

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[13] For more information on Capacity Scarcity Conditions see ISO New England's *Market Rule 1 Section III.13.7.2.1,* available at https://www.isone.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf .

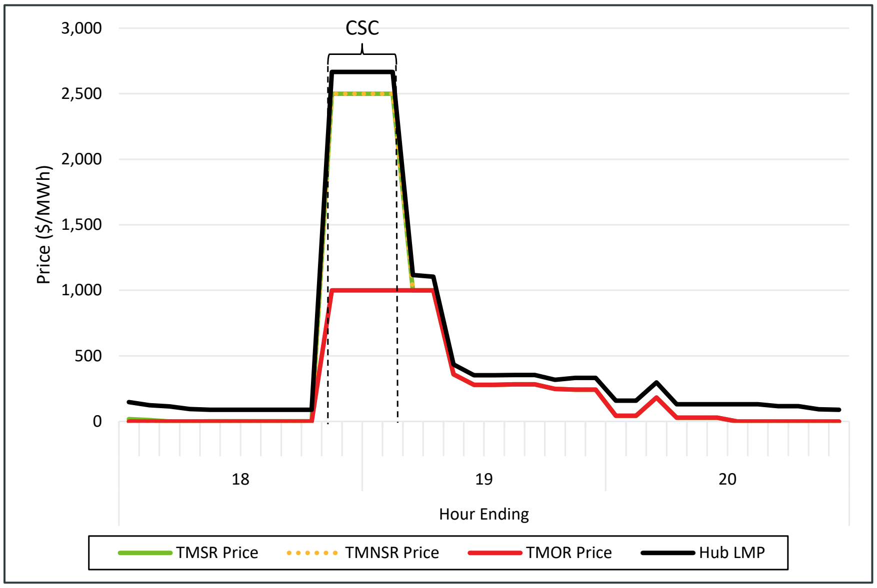
[14] This Operator Information System (OIS) load forecast was made by operators around 9:20 am on November 23, 2025. OIS load does not include load that is met by settlement-only or behind-the-meter generation.

on average, during the event and received over $7 million in PfP payments. Combined-cycle generators underperformed on a net basis as a result of unit trips leading into the event, and oil-fired steam turbines were charged more than their monthly base payments because they were not capable of responding on short notice.

2.4.2 Energy and Reserve Prices

The capacity scarcity conditions lasted 30 minutes. For the duration of the event, the 30-minute operating reserve price was $1,000/MWh, the 30-minute reserve constraint penalty factor. Additionally, the total ten-minute operating reserve price was $2,500/MWh for the first 20 minutes of the event, which is the 30-minute operating reserve price plus the $1,000 10-minute operating reserve constraint penalty factor. The reserve and energy prices are shown in Figure 2-9 below.

Figure 2-9: Energy and Reserve Prices during the November 23, 2025 Capacity Scarcity Conditions



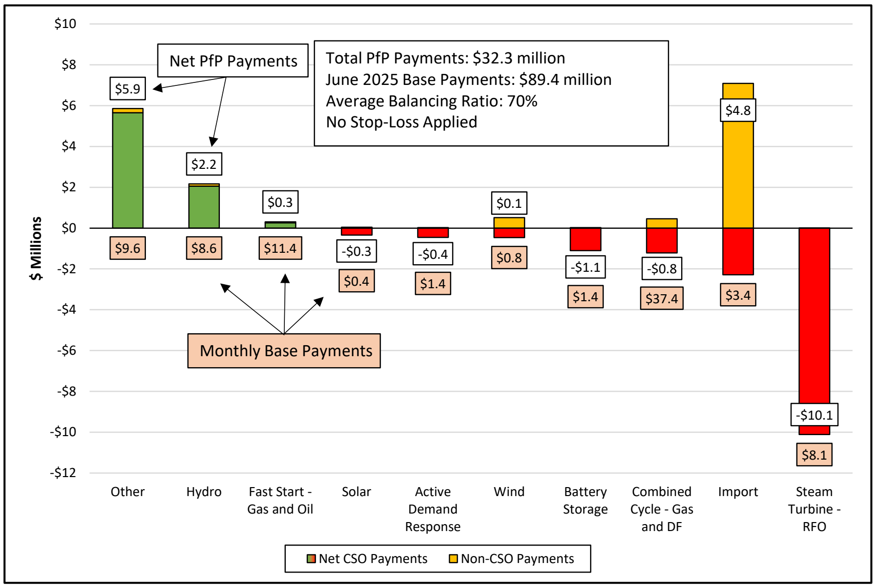
In the interval before the CSC started, the Hub LMP was $89/MWh, and there was no reserve pricing. In response to the 900 MW generation loss, both the total ten-minute and total thirty-minute reserve constraint penalty factors were activated, resulting in $1,000 total 30-minute reserve prices and $2,500 total 10-minute reserve prices. As oil, hydro, and battery storage units ramped up ten-minute spinning reserves were created, eliminating the ten-minute deficit and ten-minute RCPF pricing. Capacity shortage conditions ended as evening load declined, imports increased, and several fast-start generators completed their shutdowns and became available to provide thirty-minute operating reserves from an offline state; however, reserve pricing driven by thirty-minute operating reserves continued for roughly two hours afterward, with prices exceeding $200/MWh for about 40 minutes following the event.

2.4.3 Two-Settlement System Outcomes

Forward Capacity Market (FCM) Pay-for-Performance

During capacity scarcity conditions, every FCM-participating resource, energy market asset, and import transaction is subject to Pay-for-Performance (PfP) credits or charges based on energy market performance. Additionally, assets or imports that do not have a Capacity Supply Obligation (CSO) may earn PfP credits for any capacity provided to the system. Figure 2-10 below shows net financial PfP outcomes by resource type for both CSO and non-CSO resources for the November 23, 2025 event.

Figure 2-10: Pay for Performance Settlements by Fuel Type, November 2025[15]



November 23 PfP payments totaled $32.3 million. While payments were small relative to the June 24, 2025 PfP event, payments per shortage interval were high relative to past events due to the $9,337/MWh performance payment rate that became effective on June 1, 2025. The transitory nature of the event was reflected by the 70% balancing ratio, indicating that the system needed 70% of all contracted capacity to meet load and reserve requirements. Resources that produced more than 70% of their CSO therefore received net PfP payments. No resources reached monthly or annual stop-loss limits.

Hydro and fast-start resources performed well due to their operational flexibility, and other non-fossil fuel-fired resources were generally already online before the event. Imports with CSO underperformed relative to their obligations, but imports without CSO provided over 1,400 MW, on average, during the event and received over $7 million in PfP payments. Combined cycle generators underperformed on a net basis as a result of unit trips leading into the event, and oil-fired steam turbines were charged more than their monthly base payments because they were not capable of responding on short notice.

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[15] In this figure, “DF” refers to dual-fuel generators, and “RFO” refers to residual fuel oil. The “Other” category includes nuclear generators, biomass units, and fuel cells, while the “Hydro” category contains both traditional hydro generators and pumped storage resources.

Notably, there were over 1,700 MW of real-time scheduled exports during the event. While the event was short in duration, assessment of PfP charges to exports would have reduced export demand and would therefore likely have reduced reserve shortfalls.[16]

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[16] See the IMM's recommendation on PfP treatment of exports in our *2024 Annual Markets Report*, available at https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf .

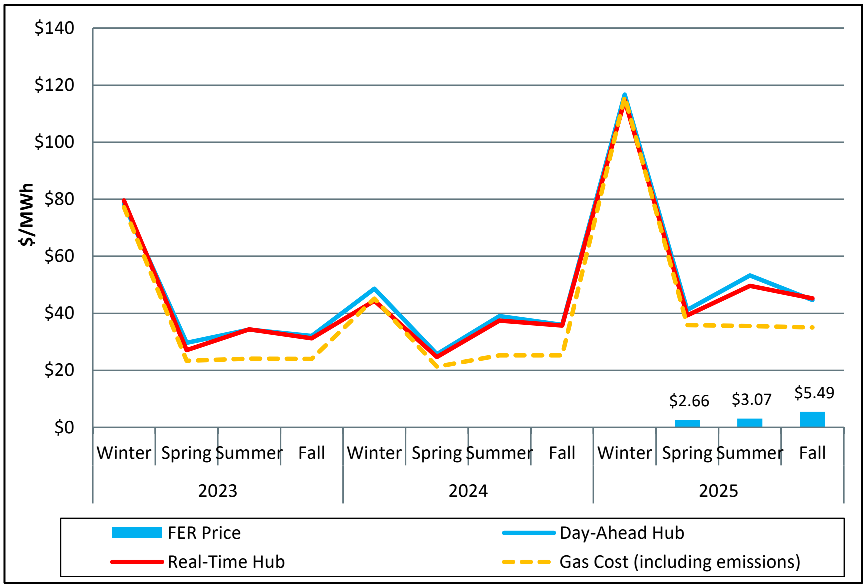
Section 3
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, market outcomes for energy, operating reserves, and regulation products.

3.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. These trends can be seen in Figure 3-1, which shows the average day-ahead and real-time energy prices, along with the estimated cost of generating electricity using natural gas in New England.[17]

Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



The average day-ahead and real-time Hub prices for Fall 2025 were $44.64 and $45.22/MWh, respectively. Additionally, the Forecast Energy Requirement (FER) price averaged $5.49/MWh, leading to a day-ahead price of $50.13/MWh for day-ahead physical generation. Average energy prices in Fall 2025 were higher than Fall 2024 prices by about $9 and $10/MWh (up 24% and 27%) in the day-ahead and real-time markets, respectively. These increases were in line with increased costs for natural gas-fired generators, which averaged $35.04/MWh (up 39%). Estimated costs for natural gas-fired generators increased due to higher natural gas prices (up 58%) and emissions costs (up 10%) in New England.

While energy prices increased, day-ahead implied heat rates fell from 18.40 MMBtu/MWh to 14.52 MMBtu/MWh year-over-year. This means that, on average, more efficient generators were marginal in Fall 2025 compared to Fall 2024. Nuclear generation increased by over 900 MW per hour year-

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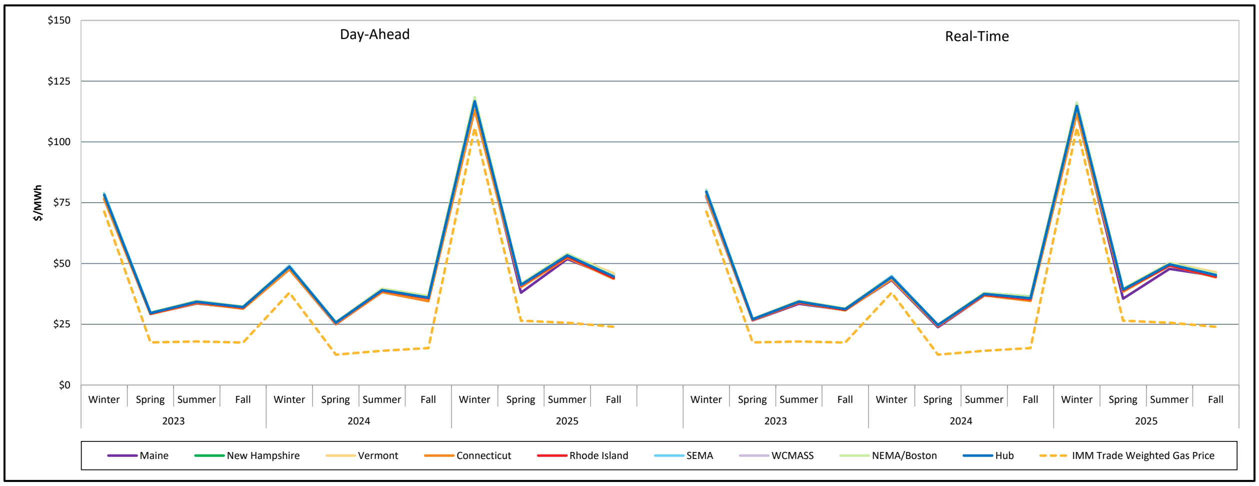
[17] The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh, which is the estimated average heat rate of a combined cycle gas turbine in New England. The natural gas cost includes estimated emissions costs.

over-year, providing more baseload generation and leading to less reliance on more expensive generators compared to last fall.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 3-2.[18] Transmission congestion is the largest driver of locational differences in energy prices.

Figure 3-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs



The Connecticut load zone saw the lowest energy prices in both the day-ahead and real-time markets – 2% lower than the Hub. Connecticut has been export-constrained more frequently in recent years, due to the addition of new highly efficient and less expensive gas-fired generators in the load zone coupled with limitations of the transmission system in exporting that power to the rest of the system. In Vermont, average prices were 3% higher than the Hub price in both the day-ahead and real-time markets. Seasonal transmission work led to the NWVT (Northwest_Vermont) Interface binding this fall, resulting in higher prices.

3.2 Marginal Resources and Transactions

This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically 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.

The percentage of load for which each fuel type set price in the real-time market since Winter 2023 is shown in Figure 3-3 below.

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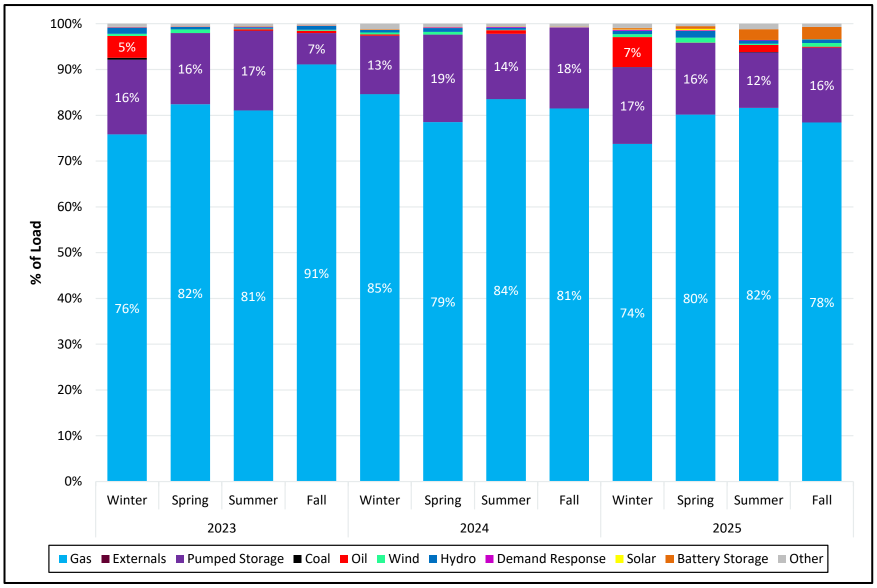
[18] A load zone is an aggregation of pricing nodes within a specific area. There are currently eight load zones in the New England region, which correspond to the reliability regions.

Figure 3-3: Real-Time Marginal Units by Fuel Type



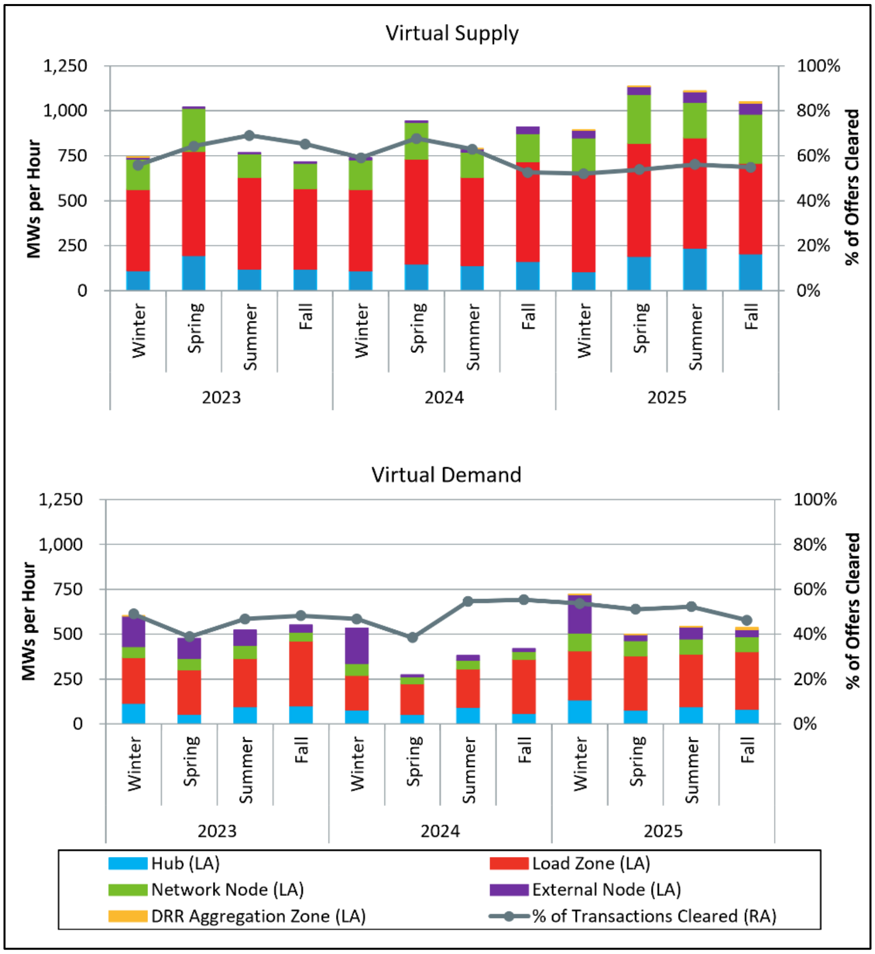
Natural gas and pumped storage generators set price for 78% and 16% of real-time load respectively in Fall 2025. Battery storage set price for 2.7% of real-time load in Fall 2025, continuing an upward trend as large-scale batteries have been added to the system. Because battery storage facilities typically charge when load is low and discharge when load is high, they frequently set price during daily peak periods.

3.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between 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) for each quarter of the past three years are shown on the left axis (LA) in Figure 3-4 below. 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 on the right axis (RA) of each chart shows cleared transactions as a percentage of submitted transactions, separately for virtual supply and virtual demand.

Figure 3-4: Cleared Virtual Transactions by Location Type



As seen in the top figure, virtual supply volumes continued to increase year-over-year, while the percentage of offers cleared stayed relatively steady. Cleared virtual supply averaged 1,051 MW per hour in Fall 2025, up 16% from Fall 2024 (909 MW per hour). The increase was driven by the expanding presence of solar and wind generation, resources that only partially engage in the day-ahead market. Solar settlement-only generators (SOGs) cannot participate in the day-ahead market, while modeled solar and wind generators (> 5 MW capacity) tend to offer high-priced energy in the day-ahead market given uncertainty about real-time weather conditions (and therefore generation capacity)[19]. These bidding conditions lead to higher volumes of renewable generation clearing in real-time than in the day-ahead market.

In Fall 2025, increased wind generation led to an increase in virtual supply that cleared at network nodes[20] compared to Fall 2024. Additionally, real-time average hourly wind generation in Fall 2025 was 367 MW higher than day-ahead cleared volumes. This difference was 154 MW higher than in

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[19] Settlement-only generators are generating units that produce less than 5 MW, are not centrally dispatched by the ISO New England control room, and are not monitored in real time. ISO-NE defines a modeled asset as, “one or more generating units at a single location that is fully visible and controllable by ISO-NE’s control room. Modeled generators bid into the Day-Ahead and/or Real-Time Energy Markets, contribute to price formation, and are therefore dispatched based on price.”

[20] Many of the network nodes with the highest volumes of cleared virtual supply are located at wind generation nodes.

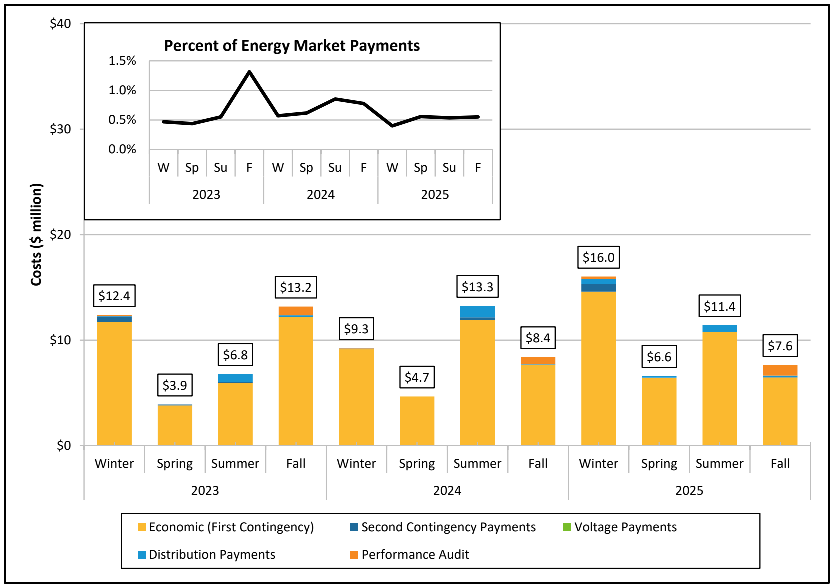
Fall 2024. Participants fill this gap and try to capture differences between day-ahead and real-time prices, particularly in export-constrained areas, by clearing higher virtual supply volumes on days when solar and/or wind generation is expected to be high and impactful on real-time prices.

Cleared virtual demand averaged 538 MW per hour in Fall 2025, up 28% from Fall 2024 (420 MW) but very similar to Fall 2023 (551 MW per hour). Compared to Fall 2024, greater volumes of virtual demand cleared across all location types. The percentage of virtual demand offers cleared fell by nine percentage points (55% in Fall 2024 vs. 46% in Fall 2025).

3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) credits are make-whole payments to generators, external transactions, or virtual participants whose costs are not fully recovered through market mechanisms following ISO dispatch instructions. NCPC categories include first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[21] Figure 3-5 below shows total NCPC by category and quarter for 2023-2025. The inset graph shows quarterly NCPC payments as a percentage of total energy market payments.

Figure 3-5: NCPC by Category



NCPC payments totaled $7.6 million in Fall 2025, down slightly from $8.4 million in Fall 2024. Economic uplift continued to comprise the largest share of NCPC, totaling $6.5 million. Performance audit uplift is common during fall, and audit payments were similar to those in prior fall seasons ($1 million). Special constraint resources received the remainder of NCPC ($0.1 million) during commitments to meet distribution needs.

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[21] NCPC payments include economic/first contingency NCPC payments, local second-contingency NCPC payments (reliability costs paid to generators providing capacity in constrained areas), voltage reliability NCPC payments (reliability costs paid to generators dispatched by the ISO to provide reactive power for voltage control or support), distribution reliability NCPC payments (reliability costs paid to generators that are operating to support local distribution networks), and generator performance audit NCPC payments (costs paid to generators for ISO-initiated audits).

3.5 Day-Ahead Ancillary Services

The day-ahead ancillary services (DA A/S) market is designed to procure sufficient capability to satisfy both the operating reserve requirements and the load forecast through a market construct. This section provides details on the performance of this market between March 1, 2025, and November 30, 2025.[22]

3.5.1 Flexible Response Services

One set of ancillary service capabilities procured via the DA A/S market ensure that the ISO has sufficient fast-starting and fast-ramping capability to quickly respond to a large supply loss. These capabilities, commonly called operating reserve capabilities, are referred to as Flexible Response Services (FRS) under this market design. Requirements for FRS capabilities have analogs to those that exist in the real-time market, including the ten-minute spinning reserve, total ten-minute reserve, and total 30-minute reserve requirements.

To help satisfy these requirements, market participants make offers for the following products:

- day-ahead ten-minute spinning reserve (DA TMSR)
- day-ahead ten-minute non-spinning reserve (DA TMNSR)
- day-ahead thirty-minute operating reserve (DA TMOR)

Requirements and Capability

In general, offered FRS capability has been many times larger than FRS requirements. This can be seen in Figure 3-6, which shows the FRS requirements relative to the offered DA A/S capability that could meet those requirements, averaged across each month.[23] This figure also includes average quarterly values in the inset table.

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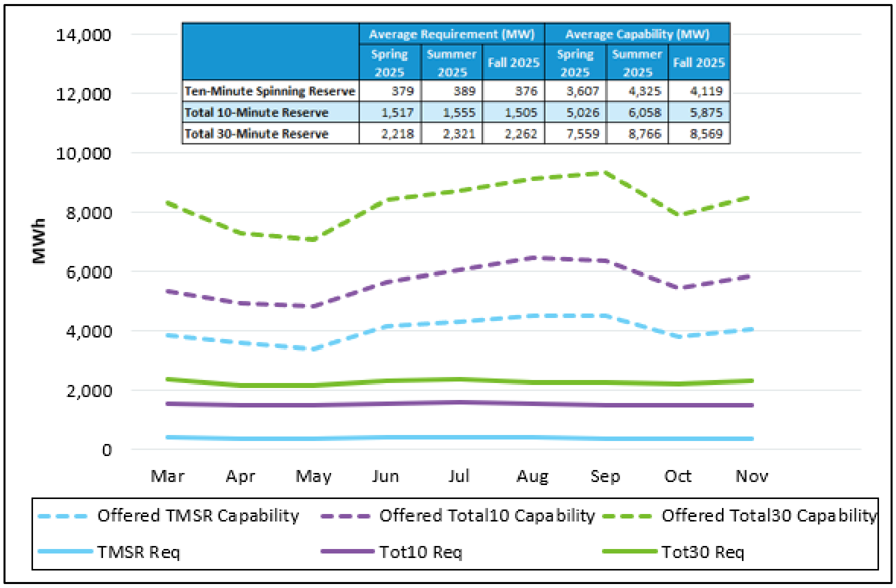
[22] The DA A/S market went live for the operating day of March 1, 2025.

[23] Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, ecomax).

Figure 3-6: Ex-ante FRS Requirements and Offered Capabilities



	Average Requirement (MW)			Average Capability (MW)		
	Spring 2025	Summer 2025	Fall 2025	Spring 2025	Summer 2025	Fall 2025
Ten-Minute Spinning Reserve	379	389	376	3,607	4,325	4,119
Total 10-Minute Reserve	1,517	1,555	1,505	5,026	6,058	5,875
Total 30-Minute Reserve	2,218	2,321	2,262	7,559	8,766	8,569

On average, offered TMSR capability exceeded the TMSR requirement in Fall 2025 by a factor of over ten times the requirement, while offered total 10- and total 30-minute capabilities exceeded requirements by more than a factor of three. While the FRS requirements – which are based on the projected first and second contingencies – did not change much quarter over quarter, the offered capability that could meet those requirements decreased modestly relative to the summer. This decreased participation is largely reflective of outages as many resources commonly undertake winter readiness maintenance in the fall.

It is important to consider the fact that some portion of offered DA A/S capability may provide greater value to the system when cleared as day-ahead energy, and if so will clear as such. Additionally, some DA A/S capability is offered on resources that can only provide that capability from an online state, and these resources may or may not receive a day-ahead commitment. Finally, some DA A/S capability may be offered on resources that prove unable to provide the service due to binding transmission constraints. Figure 3-7 below shows the same requirements and cleared quantities as Figure 3-6 above but adjusts the offered capability downward by the amounts of DA A/S capability cleared for energy, DA A/S capability on non-fast start resources that did not receive a DA commitment, and DA A/S capability on resources behind binding transmission constraints. The intent is to provide an 'ex-post' view of available DA A/S capability.

Figure 3-7: Ex-post FRS Requirements and Offered Capabilities

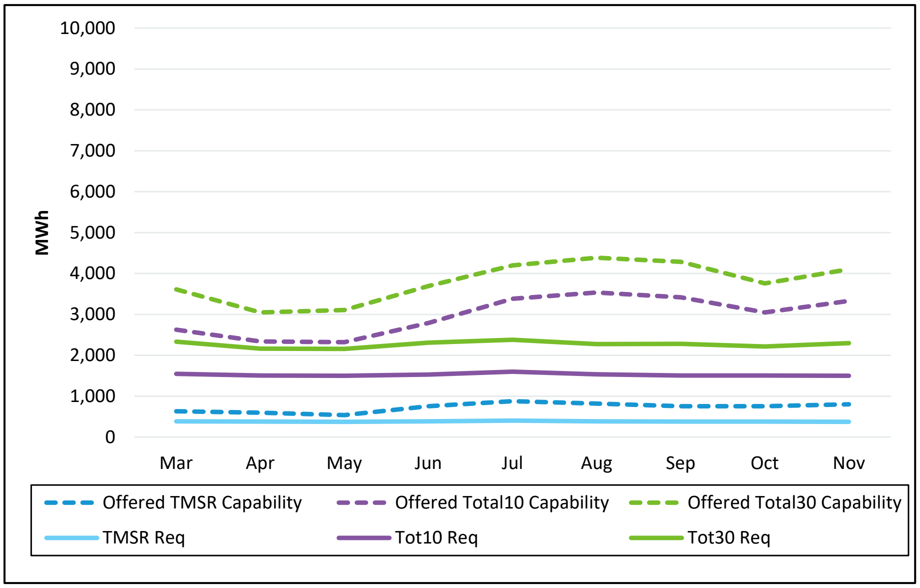
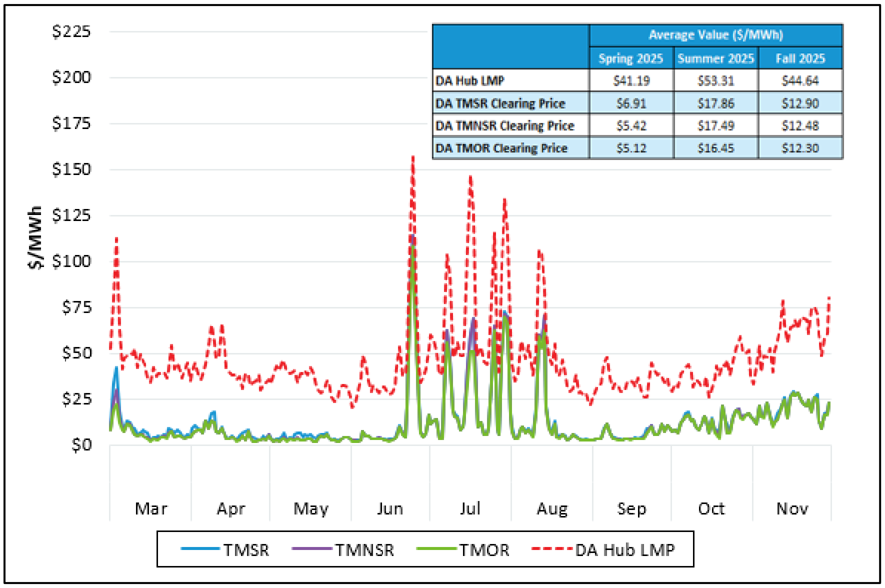


Figure 3-7 shows far less DA A/S capability available from an ex-post perspective, particularly for the capability that can satisfy the TMSR requirement. This tighter supply can contribute to opportunity costs being reflected in DA A/S clearing prices, most notably for TMSR.

Clearing

FRS clearing prices have generally moved in-line with day-ahead energy prices. This can be seen in Figure 3-8, which shows daily average clearing price values over the first nine months of the DA A/S market, along with the daily average day-ahead Hub LMP. This figure also includes average quarterly prices in the inset table.

Figure 3-8: FRS Clearing Prices



	Average Value ($/MWh)		
	Spring 2025	Summer 2025	Fall 2025
DA Hub LMP	$41.19	$53.31	$44.64
DA TMSR Clearing Price	$6.91	$17.86	$12.90
DA TMNSR Clearing Price	$5.42	$17.49	$12.48
DA TMOR Clearing Price	$5.12	$16.45	$12.30

FRS clearing prices were lower and less volatile in Fall 2025 than in Summer 2025; on average, prices for these products ranged between $12-$13/MWh in the fall, declining from between $16-$17/MWh in the summer.[24] To date, FRS clearing prices have tended to track closely together as it is commonly the marginal value of the total 30-minute reserve requirement that sets the price for all three products. At a monthly level, clearing prices trended upwards during the fall; for example, TMOR clearing prices averaged $5.43/MWh in September 2025, $12.20/MWh in October 2025, and $19.25/MWh in November 2025. These price increases were consistent with day-ahead energy market prices that also gradually increased over the period. Higher energy market prices can lead to higher DA A/S clearing prices as they can increase the opportunity costs that are incurred by the resources needed to satisfy the reserve requirements.

3.5.2 Energy Imbalance Reserves

The other ancillary service procured in the DA A/S market is reserve capability that can be used to help meet the load forecast. Physical supply resources within New England that have 60-minute reserve capability can now be compensated for this capability by clearing offers on a new ancillary service product called Energy Imbalance Reserve (EIR). The market clearing engine procures this product via the Forecast Energy Requirement (FER) constraint, which can be satisfied by a mix of day-ahead energy awards cleared on physical resources and EIR awards. Both groups (i.e., physical supply resources with day-ahead energy awards and EIR awards) are paid the FER Price as both contribute to satisfying the FER constraint.

Generally, only small amounts of EIR are needed to satisfy the FER constraint. This can be seen in Figure 3-9, which shows the average cleared MWh of EIR by month. This figure also includes relevant quarterly statistics in the inset table.

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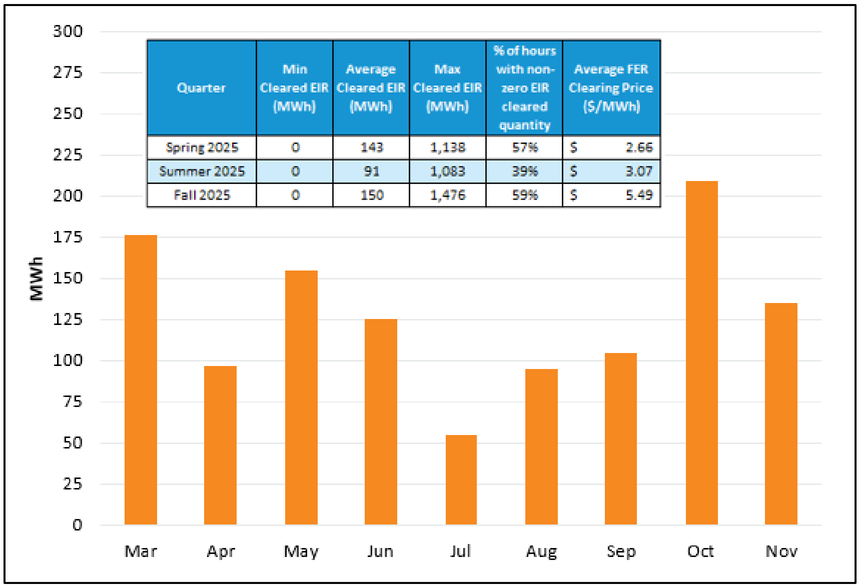
[24] Under the DA A/S market design, DA A/S products are paid an initial credit at the applicable DA A/S clearing price and face a closeout charge whenever the real-time hub LMP exceeds the strike price. This figure reflects the clearing prices that are used to establish the initial credits for the FRS products. The impact of closeout charges on settlements is presented in Section 3.5.3.

Figure 3-9: EIR Cleared Awards and Related Statistics



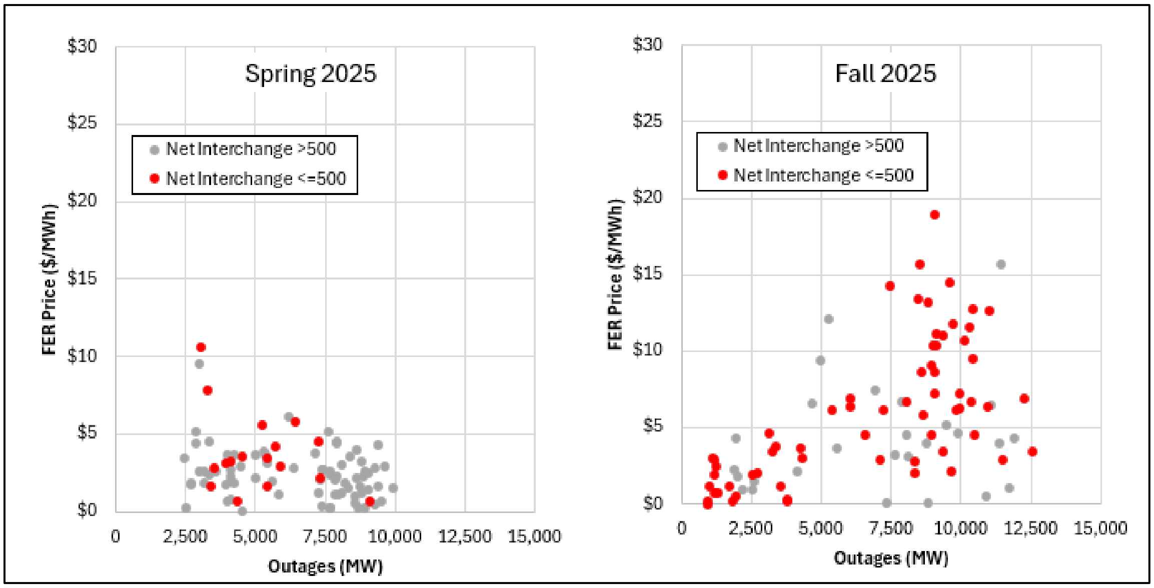
Quarter	Min Cleared EIR (MWh)	Average Cleared EIR (MWh)	Max Cleared EIR (MWh)	% of hours with non-zero EIR cleared quantity	Average FER Clearing Price ($/MWh)
Spring 2025	0	143	1,138	57%	$ 2.66
Summer 2025	0	91	1,083	39%	$ 3.07
Fall 2025	0	150	1,476	59%	$ 5.49

The average amount of EIR cleared to satisfy the FER constraint rose moderately from Summer 2025 (91 MWh) to Fall 2025 (150 MWh) as did the percentage of hours that had any EIR clearing (from 39% of hours to 59% of hours). Meanwhile, the average FER price rose moderately between Summer 2025 ($3.07/MWh) and Fall 2025 ($5.49/MWh), indicating that, when there was a need for additional physical supply to meet the load forecast, it was, on average, more expensive to procure on a $/MWh basis.

FER Pricing

While FER pricing is complex, depending on supply- and demand-side dynamics as well as the load forecast, two factors that contributed to higher prices in Fall 2025 were the high level of generator outages and the reduction in net interchange in the day-ahead market. This can be seen in Figure 3-10, which depicts average daily FER prices ($/MWh) and generator outages (MW) for both Spring 2025 and Fall 2025. The observations depicted in this figure add an additional dimension that captures the level of net interchange; the categories shown here indicate when average daily net interchange was less than or equal to 500 MWh (red) or greater than 500 MWh (gray).

Figure 3-10: Daily Average FER Prices, Generator Outages, and Net Interchange Levels for Spring and Fall 2025



While both Spring 2025 and Fall 2025 had high levels of generator outages, FER pricing in the fall tended to be considerably higher. One factor that contributed to this price increase was the frequency of days with high generator outage levels (defined here as greater than 10,000 MW); the fall had 17 days when the daily average level exceeded this threshold compared to zero days in the spring. Additionally, there was a notable shift in day-ahead net interchange volumes between the two seasons; the fall had 64 days when the daily average net interchange was less than or equal to 500 MWh while the spring had just 17 days at or below this level. Both these factors work to reduce the amount of physical supply that can satisfy the FER constraint, which puts upward pressure on FER pricing, all else equal.

3.5.3 Settlements

The four DA A/S products – DA TMSR, DA TMNSR, DA TMOR, and EIR – are paid an initial credit at the applicable DA A/S clearing price and incur a closeout charge whenever the real-time Hub LMP exceeds the strike price. For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

To date, the DA A/S products have represented a small percentage of overall energy and ancillary services (E&AS) costs.[25] This can be seen in Table 3-1, which shows the *net* settlements for the DA A/S products for the first three quarters.

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[25] Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

Table 3-1: DA A/S Settlements ($millions)

Concept	Spring 2025	Summer 2025	Fall 2025	Total
DA TMSR (net)	$3.7	$16.6	$8.5	$28.8
DA TMNSR (net)	$6.3	$26.1	$16.1	$48.5
DA TMOR (net)	$2.9	$13.3	$7.8	$24.0
EIR (net)	$0.2	$1.4	$1.7	$3.3
Total (net)	**$13.1**	**$57.4**	**$34.1**	**$104.6**
Total E&AS Costs	$1,284	$2,345	$1,607	$5,237
% Total E&AS Cost	1%	2%	2%	2%

Total net ancillary services payments decreased between Summer 2025 ($57.4 million) and Fall 2025 ($34.1 million). This decrease was in line with the change in total E&AS costs observed between the two periods and the result was that DA A/S costs represented 2% of E&AS costs in both quarters.

FER Credit

While not made to the DA A/S products, the FER credit is an additional payment that was introduced as part of the market design reforms associated with DA A/S market. This credit represents the payment to physical supply resources (i.e., generators, demand response resources, and imports) with day-ahead energy awards for their contribution to satisfying the FER constraint. Unlike resources that clear EIR awards, however, resources that receive the FER credit as a result of clearing day-ahead energy do not face a closeout charge based on their energy output in the real-time energy market.

FER credits tend to be much larger than the payments made to EIR awards as nearly all of the FER is satisfied by cleared energy awards to physical suppliers. Total FER credits by quarter are shown in Table 3-2 below.

Table 3-2: FER Settlements ($millions)

	Spring 2025	Summer 2025	Fall 2025	Total
FER Credit	$74.4	$122.2	$166.9	$363.5
Total E&AS Costs	$1,284	$2,345	$1,607	$5,237
% Total E&AS Cost	6%	5%	10%	7%

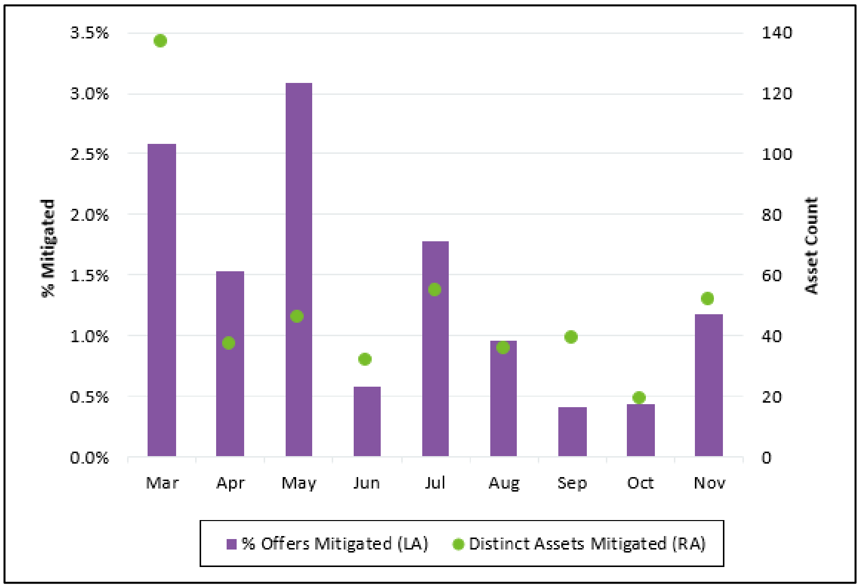
FER credits totaled $166.9 million in Fall 2025, which represented 10% of total E&AS costs for the season. Several factors that contributed to the increase in FER credits relative to prior quarters are discussed in the FER pricing subsection within Section 3.5.2. Since the start of the DA A/S market, the FER credit has totaled $363.5 million, representing 7% of total E&AS costs.

3.5.4 Mitigation

DA A/S mitigation occurs when DA A/S offer prices exceed conduct test thresholds, and the impact of those offers on clearing prices is determined to exceed impact test thresholds.[26] One unique aspect of the DA A/S mitigation design is that a DA A/S product offer is mitigated in a given hour if the offer fails the conduct test in that hour and there is a price impact failure in *any* hour of that same day. In other words, the impact test failure does not need to occur in the same hour as the conduct test failure for DA A/S mitigation to occur.

The occurrence of DA A/S mitigation has generally decreased since the inception of the market. This can be seen in Figure 3-11 below, which shows the percentage of DA A/S offers that were mitigated on the left axis (LA)[27] and the count of the distinct assets that were mitigated on the right axis (RA).

Figure 3-11: DA A/S Mitigations



The percentage of all asset-product-hours that were mitigated fell from 1.1% in Summer 2025 to 0.7% in Fall 2025. The count of distinct assets that were mitigated has ranged between 19-55 over the last eight months, leveling off since March (when 137 assets were mitigated). It is likely that a growing familiarity with the market design may be reducing the incidence of mitigation.

3.5.5 Gaussian Mixture Model Performance

In order to estimate several key values associated with the DA A/S market, the ISO developed a statistical model of real-time LMPs that depends on a set of explanatory variables that are known in

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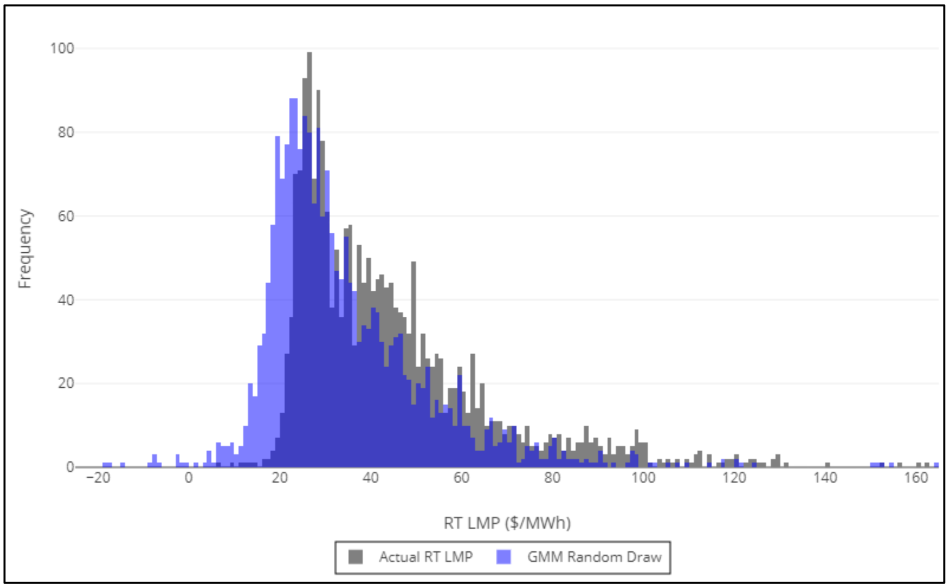
[26] For detailed rules regarding DA A/S conduct and impact tests, See the ISO's *Market Rule I*, Section III.A.8.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[27] Given that one asset can make offers on up to four DA A/S products per hour, this percentage represents the count of mitigated asset-product-hours relative to the total count of asset-product-hours in the period.

advance of the day-ahead market (e.g., load forecast, gas price).[28] The statistical model that the ISO employs is a Gaussian Mixture Model (GMM), which produces a set of normal (i.e., Gaussian) distributions whose means and variances change depending on the values of these explanatory variables.

One way to see how well the GMM captures the shape of the distribution of actual real-time LMPs is to take a random draw from it for each hour and compare this against the distribution of the actual real-time Hub LMPs. This can be seen in Figure 3-12 below, which shows these values for each hour between September 1, 2025, and November 30, 2025.

Figure 3-12: Distribution of Actual LMP and Random Draw from the GMM



Although biased downward, the shape of the distribution of random draws from the GMM generally matched the shape of the distribution of actual real-time Hub LMPs.[29] The standard deviation of the random draw distribution ($18.75/MWh) was lower than the distribution of actual real-time LMPs ($30.52/MWh). However, this was mostly driven by two hours on November 23 when the actual real-time LMP exceeded $500/MWh;[30] excluding these outlier hours, the standard deviation of real-time LMPs ($22.72/MWh) was comparable to the standard deviation of the random draw distribution.

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[28] More information about the model that the ISO uses to forecast the real-time LMP can be found in the ISO's *Day-Ahead Ancillary Services Monthly Real-Time LMP Modeling Memo*, available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/daas-monthly-memo.

[29] The mean of the distribution of random draws from the GMM depicted in this figure was $34.39/MWh. The mean of this distribution could change depending on the draws but one would expect it to be centered around the average expected real-time LMP of $34.70/MWh.

[30] For more information on the November 23, 2025 capacity shortage conditions see Section 2.4.

Expected Real-Time LMP

The expected real-time LMP for an hour is the mean of the normal distributions produced by the GMM. This value is important because the hourly strike price, which is used in the settlement of DA A/S awards, is set equal to the expected real-time LMP for that hour plus a $10/MWh adder.

During Fall 2025, the expected real-time LMP values that came from the GMM tended to underpredict the actual real-time LMPs; the average expected real-time LMP ($34.70/MWh) was $10.52/MWh lower than the average actual real-time LMP ($45.22/MWh). This result isn't fully unexpected given that there were several hours when the actual real-time LMP exceeded $500/MWh (on November 23), while the expected real-time LMP never exceeded $100/MWh. The impact of these high actual real-time prices is reduced when we compare the medians; the median expected real-time LMP ($32.20/MWh) was $6.71/MWh lower than the median actual real-time LMP ($38.91/MWh).

Expected Closeout

The ISO's Gaussian Mixture Model also produces expected closeouts for each hour of an operating day. Recall that an asset with a DA A/S award incurs a closeout charge any time the real-time Hub LMP exceeds the strike price. The *expected* closeout is the ISO's estimate of this closeout charge and is calculated using the normal distributions that are produced as part of the GMM. As the expected closeout charge is a cost that could otherwise be avoided by not taking on a DA A/S award, it forms a key part of an asset's competitive offer and its default benchmark level.[31]

Actual closeouts tend to be much more volatile than expected closeouts given that the former is a single realized outcome while the latter is a probabilistic expectation based upon a range of possible real-time outcomes. This can be seen in Figure 3-13 below, which shows daily averages of actual closeouts and two different expected closeouts: the solid red line shows the value that comes directly from the GMM[32] and the dashed red line shows the value after intervention by the IMM.[33] This figure also includes average quarterly values in the inset table.

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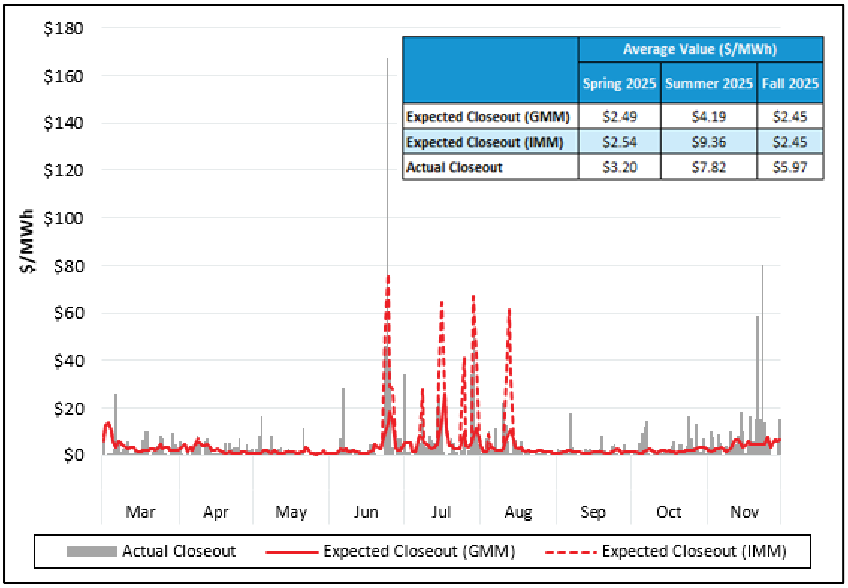
[31] Participants are free to establish their own benchmark levels via consultation with the IMM.

[32] The ISO calculates expected closeout values for the same hour as part of two scheduled jobs – the first calculation occurs as part of the job that produces strike prices and the second calculation occurs upon the close of the day-ahead market submission window. Generally, the expected closeout values from these two jobs are very similar. The IMM has a practice of using the higher of these two values in its mitigation process so as to prevent good-faith offers from getting mitigated. It is the maximum values that are depicted in this figure.

[33] The IMM has a process to intervene in the setting of expected closeouts when the output from the GMM is not consistent with observable market conditions. When the IMM intervenes, the value set by the IMM becomes the effective value that is used in the DA A/S mitigation assessment. Absent this action, competitive DA A/S offers may be mitigated inappropriately.

Figure 3-13: Actual and Expected Closeouts

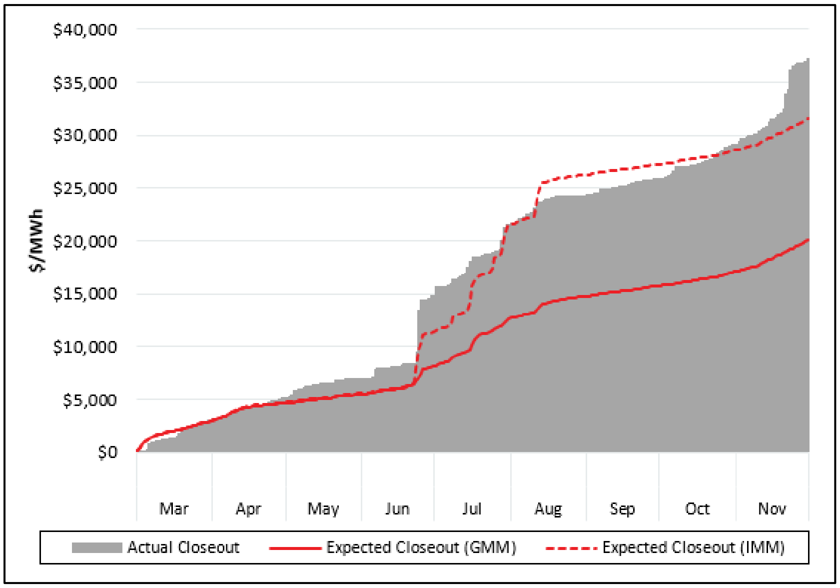


	Average Value ($/MWh)		
	Spring 2025	Summer 2025	Fall 2025
Expected Closeout (GMM)	$2.49	$4.19	$2.45
Expected Closeout (IMM)	$2.54	$9.36	$2.45
Actual Closeout	$3.20	$7.82	$5.97

On average, actual closeouts in Fall 2025 ($5.97/MWh) exceeded the expected closeouts from the GMM ($2.45/MWh) despite actual closeouts exceeding expected values in only 29% of hours. Expected closeouts frequently exceed actual closeouts because expected closeout values are always greater than $0/MWh (as there is always some probability, however small, that the real-time LMP exceeds the strike price) while actual closeout values will be $0/MWh in many hours. During Fall 2025, the actual closeout was $0/MWh in ~65% of hours. The IMM did not intervene in Fall 2025 to set expected closeouts as it did in Summer 2025, when expected prices from the GMM, at times, exhibited a large disconnect from contract prices observed on commodity trading platforms.

While expected and actual closeouts will differ on an hourly basis, it is reasonable to expect that these values will align cumulatively over time. This relationship is observed in Figure 3-14 below, which shows the cumulative actual closeout with gray bars and the two cumulative expected closeouts.

Figure 3-14: Actual and Expected Closeouts, Cumulative



The cumulative actual closeouts exceeded the cumulative expected closeouts that came directly from the GMM by a significant margin over the first nine months of the DA A/S market. This is also true for just Fall 2025; cumulative actual closeouts totaled $13,000/MWh while cumulative expected closeouts totaled only $5,300/MWh. This means that a hypothetical asset that cleared one MWh of DA A/S awards in every hour over during Fall 2025 would have incurred a loss of over $7,000/MWh if DA A/S clearing prices had been exactly equal to the GMM-produced expected closeouts.[34]

3.5.6 DA A/S Incremental Cost Estimation

The IMM performed market simulations to better understand the incremental impact of DA A/S design on market outcomes relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. To perform these simulations, the IMM used an in-house market simulation tool known as the Integrated Market Simulator (IMS) that both replicates the logic of the day-ahead market (DAM) that exists in production today[35] and also provides the flexibility to modify constraints and other key inputs.

The results presented in this section are an update to one of the simulations that appeared in the IMM's Summer 2025 Quarterly Markets Report.[36] These simulation results now reflect the period

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[34] It is important to note, however, that, while the expected closeout is supposed to represent the basis of a competitive DA A/S offer, DA A/S clearing prices are not expected to equal the expected closeout for a variety of reasons, including that 1) clearing prices will include opportunity costs and 2) participants are allowed to offer up to the conduct test threshold price without triggering mitigation.

[35] IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, although it does not produce exactly the same results.

[36] For more information on the Summer 2025 simulation results, see the IMM's *Summer 2025 Quarterly Markets Report,* DA A/S Incremental Cost Estimation (Section 3.5.7), available at: https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf.

March 1, 2025 to November 30, 2025. Importantly, all results should be viewed as indicative given that they result from simulations.

Incremental Cost of DA A/S

In order to estimate the impact of the DA A/S market on total energy market costs, the following scenarios were simulated:

1) **No DA A/S**: a scenario in which all the DA A/S constraints in the day-ahead market (FER, FRS) are 'turned off.' This scenario is intended to reflect the pre-March 2025 day-ahead market.
2) **DA A/S:** a scenario in which all the DA A/S constraints in the day-ahead market (FER, FRS) are 'turned on.' This scenario is intended to reflect the current day-ahead market.

The following table provides a high-level comparison of these two scenarios.[37]

Table 3-3: Estimated Change in Market Costs as a result of the DA A/S Market

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA Energy	**$4,842**	**$5,133**	**$291**	**6.0%**
LMP	$4,842	$4,748	-$93	-1.9%
FER Price	$0	$385	$385	
DA A/S	**$0**	**$108**	**$108**	
Credits	$0	$202	$202	
Closeouts	$0	-$94	-$94	
Total DA Charges/Credits	**$4,842**	**$5,241**	**$399**	**8.2%**
Cost of Incremental RT Energy[38]	$58.6	$59.3	$0.7	1.2%
Total Cost/Revenue Change	**$4,900**	**$5,300**	**$400**	**8.2%**

We estimate that the DA A/S market has resulted in an increase of $400 million (8.2%) in total costs over the first nine months. The majority of the incremental cost increases are in the form of higher day-ahead energy market payments, where we estimate an increase of $291 million relative to the 'No DA A/S' scenario. While energy payments via the day-ahead LMP decreased by $93 million relative to the 'No DA A/S' scenario, this is more than offset by a $385 million FER payment, which represents a new payment to physical supply resources (i.e., generators, DRRs, and imports) with day-ahead energy awards. Net payments to the new DA A/S awards ($108 million), which include DA TMSR, DA TMNSR, DA TMOR, and EIR, represent nearly all of the remaining estimated cost increase. The simulations indicate very little change in incremental real-time energy purchases between the two scenarios.

The DA A/S market design changes have tended to result in lower day-ahead LMPs but higher overall day-ahead energy market prices when the FER price is included. This can be seen in Figure

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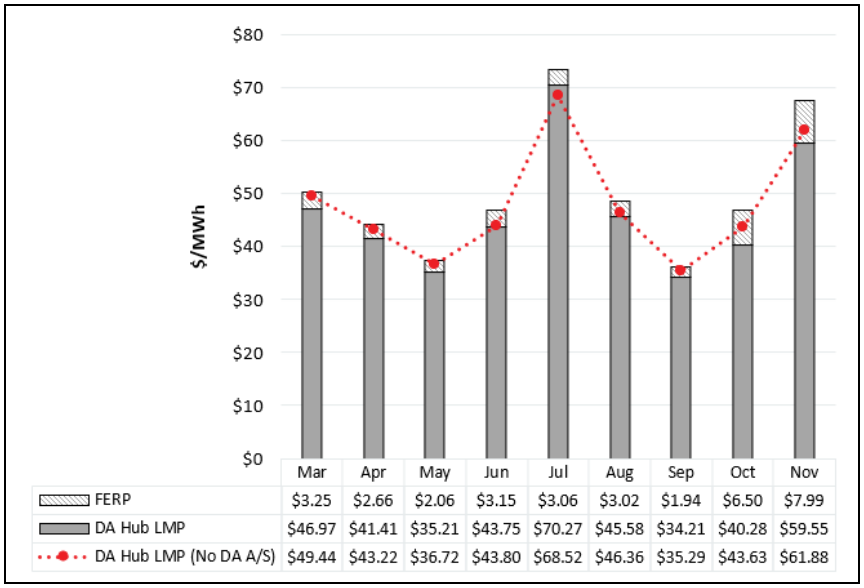
[37] The scenarios summarized here assume that there was no change in the real-time LMPs.

[38] This exists because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Consequently, this field is calculated as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic.

3-15 below, which shows the average actual day-ahead LMP and FER price by month compared with the average estimated day-ahead LMP from the ‘No DA A/S’ scenario.

Figure 3-15: Comparison of Actual DA LMP and FER Price against Estimated DA LMP with no DA A/S



	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
▨ FERP	$3.25	$2.66	$2.06	$3.15	$3.06	$3.02	$1.94	$6.50	$7.99
■ DA Hub LMP	$46.97	$41.41	$35.21	$43.75	$70.27	$45.58	$34.21	$40.28	$59.55
··●·· DA Hub LMP (No DA A/S)	$49.44	$43.22	$36.72	$43.80	$68.52	$46.36	$35.29	$43.63	$61.88

The sum of average actual day-ahead LMP and FER price exceeds the average ‘No DA A/S’ LMP in all nine months. This is an expected result of the market design as the marginal cost of energy supply in the day-ahead market is now generally higher than the ‘No DA A/S’ scenario and this energy supply is now compensated through a combination of the LMP and the FER price instead of only through the LMP.

3.6 Real-Time Operating Reserves

This section provides details about real-time operating reserve pricing and payments. ISO-NE procures three types of real-time reserve products: (1) ten-minute spinning reserve (TMSR), (2) ten-minute non-spinning reserve (TMNSR), and (3) thirty-minute operating reserve (TMOR). Real-time reserve prices have non-zero values when the ISO must re-dispatch resources to satisfy a reserve requirement.[39] Resources providing reserves during these periods receive real-time reserve payments.

Real-time Reserve Pricing

The frequency of system-level non-zero reserve pricing for each product, along with the average price during these intervals, for the past three fall seasons is provided in Table 3-4 below.[40]

Table 3-4: Hours and Level of Non-Zero Reserve Pricing

Product	Fall 2025		Fall 2024		Fall 2023	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$22.63	133.4	$6.39	196.1	$24.91	214.0
TMNSR	$200.38	9.8	$15.06	0.3	$128.97	29.4
TMOR	$151.86	9.7	$0.00	0.0	$145.17	18.3

In Fall 2025, reserve pricing occurred less frequently but at a higher magnitude than in Fall 2024. The TMSR product was priced greater than $0/MWh in less than 150 hours in Fall 2025, with an average clearing price of $22.63/MWh. The average for the quarter omitting November 23, the day of the capacity scarcity conditions, was $13.82/MWh. The total ten-minute and thirty-minute reserve requirements were priced greater than $0/MWh for less than ten hours each. TMNSR prices were generally driven by the TMOR product. There were only six five-minute intervals in the quarter in which the TMNSR price was greater than the TMOR price. In four of those intervals the TMNSR reserve constraint penalty factor was binding, resulting in a $1,500/MWh difference between the TMNSR and TMOR price and the $50/MWh difference between the average prices in Table 3-4.

Overall, system conditions were generally not tight and there were ample reserves to satisfy the reserve requirements throughout the quarter, with the exception of the capacity scarcity conditions on November 23.

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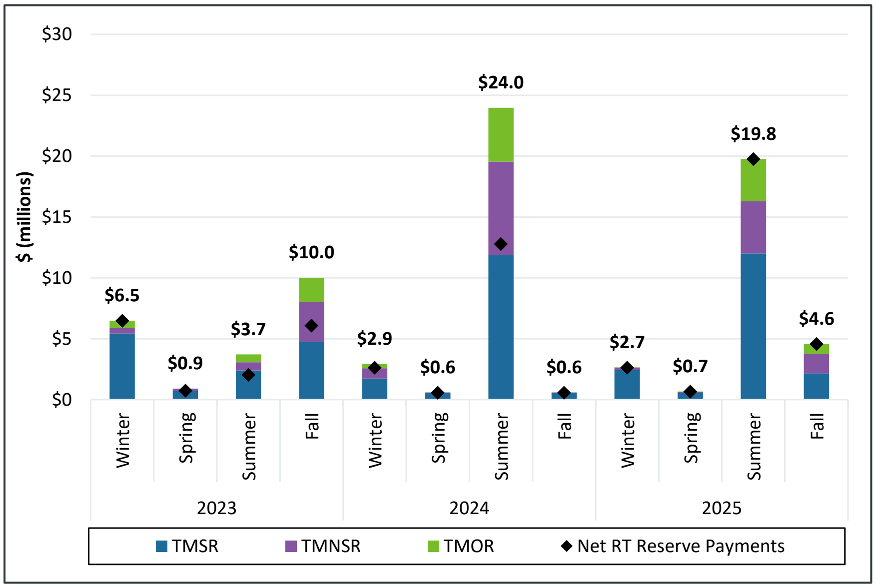
[39] Real-time operating reserve requirements are utilized to maintain system reliability. There are several real-time operating reserve requirements: (1) the ten-minute reserve requirement; (2) the ten-minute spinning reserve requirement; (3) the minimum total reserve requirement; (4) the total reserve requirement; and (5) the zonal reserve requirements. For more information about these requirements, see *Section III Market Rule 1: Standard Market Design*, Section III.2.7A, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[40] In addition to the system-level prices shown here, the zonal thirty-minute reserve requirement in NEMA/Boston bound for two five-minute intervals during the Fall 2023 season. As a result, non-zero reserve prices were $28.22/MWh for all reserve products provided in NEMA/Boston during those intervals, while the system-level reserve prices were $0/MWh.

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-16 below.[41] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to forward reserve resources providing real-time reserves).[42]

Figure 3-16: Real-Time Reserve Payments by Product and Zone



Capacity scarcity conditions on November 23 were the primary diver of reserve payments in Fall 2025. Total season payments totaled roughly $4.6 million, half of which was paid on November 23.

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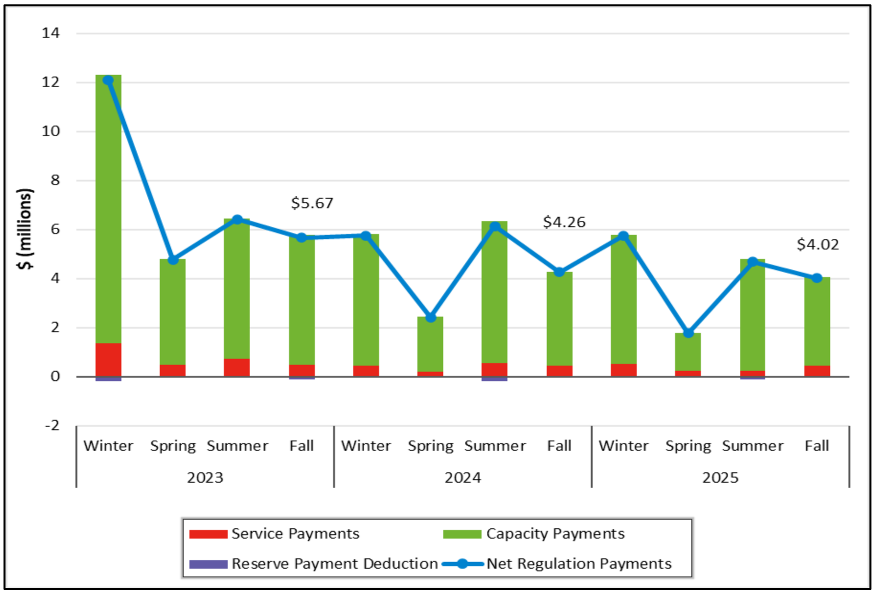
[41] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

[42] The FRM was a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations were reduced by a forward reserve obligation charge so that a resource is not paid twice for the same service. This program was sunset with the implementation of Day-Ahead Ancillary Services. For more information about day-ahead ancillary services, see 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.

3.7 Regulation

Regulation is an essential reliability service provided by generators and other resources in real-time. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments since Winter 2023 are shown in Figure 3-17 below.

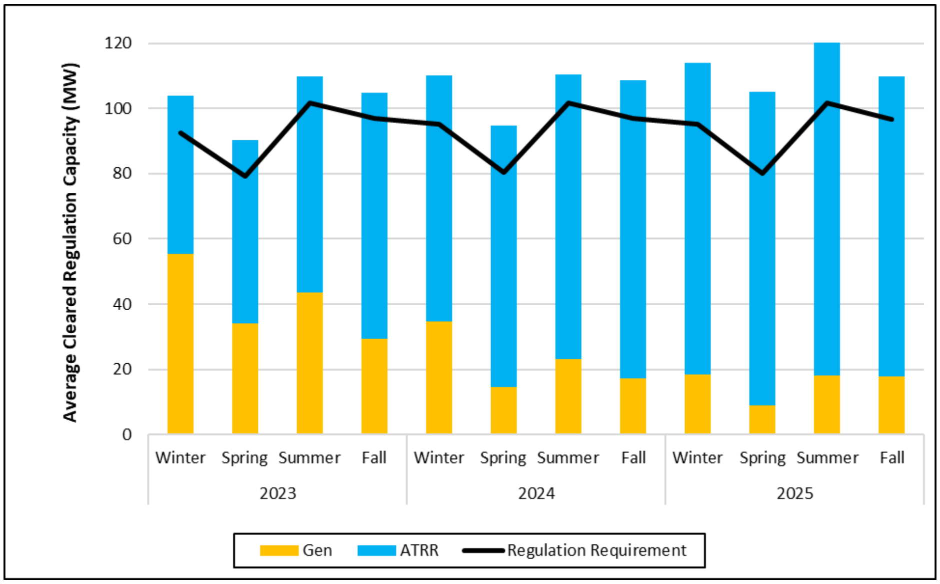
Figure 3-17: Regulation Payments



Total regulation market payments were $4.02 million during Fall 2025, down 6% from $4.3 million in Fall 2024. The decrease in payments resulted primarily from lower capacity prices (down 21%). Capacity prices decreased due to a decline in regulation offer prices, as lower cost alternative technology regulation resources continue to make up a larger share of the regulation mix.

Two different types of resources can provide regulation: traditional generators and alternative technology regulation resources (ATRRs). Almost all ATRRs in the New England market are battery resources that can opt to participate solely as regulation resources or may choose to provide a broader combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation. The regulation resource mix is shown in Figure 3-18 below.

Figure 3-18: Average Cleared Regulation MW by Resource Type



In Fall 2025, the total average cleared regulation was 110 MW, of which ATRRs (blue bars) provided 92 MW, representing 84% of the total regulation cleared. Regulation capacity available from ATRRs averaged 598 MW in Fall 2025, up from 237 MW in Fall 2024. This shift reflects the continued increase in installed battery capacity across the region. The change in resource mix also indicates that battery resources are lower-cost options for regulation, as ATRRs are increasingly used instead of traditional generators in the merit order for regulation market commitment.

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. This section first presents two metrics on system-wide structural market power. Next, the section provides statistics on system and local market power flagged by the automated mitigation system. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

4.1 Pivotal Supplier and Residual Supply Indices

This section examines opportunities for participants to exercise market power in the real-time market.[43] Two metrics are presented here, both of which identify instances when the largest supplier has market power:

1) The *residual supply index* (RSI): the RSI represents the amount of demand and reserves that the system could satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

2) The *pivotal supplier test* (PST): pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[44] to the sum of each participant's total supply that is available within 30 minutes.[45] When a participant's available supply exceeds the supply margin, they are pivotal.

The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 4-1 below.

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[43] Many resources in New England are owned by companies that are subsidiaries of larger firms. Consequently, tests for market power are conducted at the parent company level.

[44] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [$Reserve\ Requirement$]

[45] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

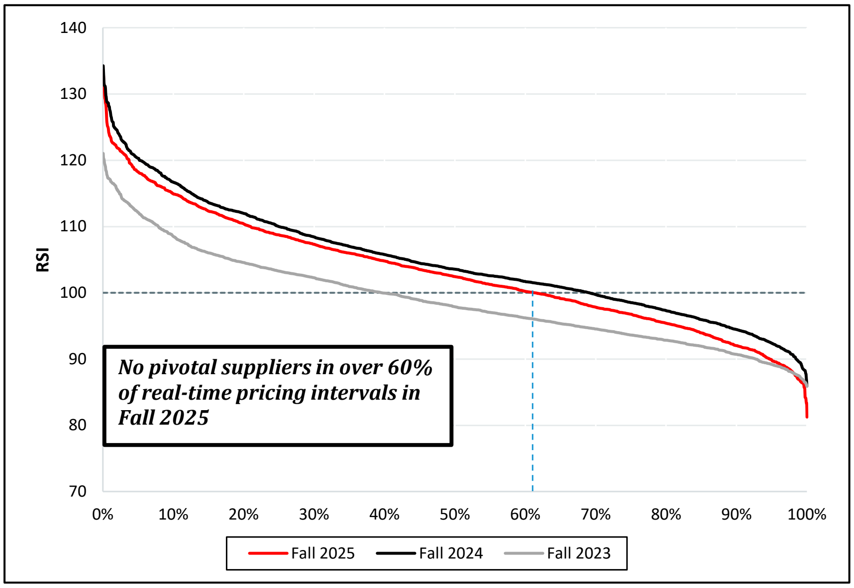
Table 4-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%
Fall 2024	104.7	31%
Winter 2025	101.3	47%
Spring 2025	105.7	25%
Summer 2025	104.4	31%
Fall 2025	103.0	39%

The RSI was above 100 in most quarters of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. There was at least one pivotal supplier in 39% of real-time pricing intervals in Fall 2025, which was higher than the Fall 2024 frequency due to lower margins that resulted from decreased availability of pumped-storage generators. Pumped-storage units typically provide large volumes of reserves, as they can come online at their full capacity quickly. Higher loads and less interchange also contributed to the lower RSI and higher intervals with pivotal suppliers.

Duration curves that rank the average hourly RSI over each fall quarter in descending order are illustrated in Figure 4-1 below. The figure shows the percentage of hours when the RSI was above or below 100 for each quarter. An RSI below 100 indicates the presence of at least one pivotal supplier.

Figure 4-1: System-Wide Residual Supply Index Duration Curves



In Fall 2025, the RSI was lower than that of Fall 2024 across all ranked observations, reflecting the lower supply margins.

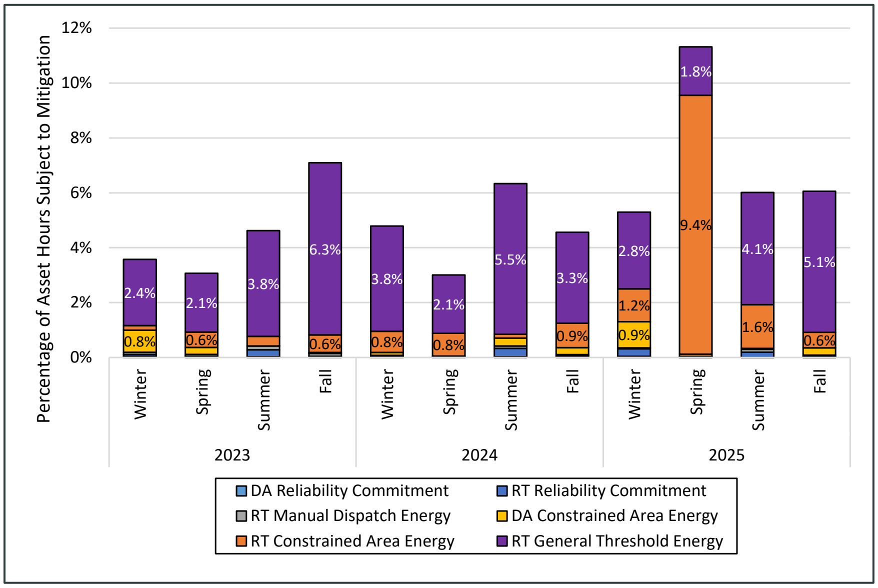
4.2 Energy Market Supply Offer Mitigation

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. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Fall 2025.

Energy Market Mitigation Frequency

A structural test failure serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours with a structural test failure from Winter 2023 to Fall 2025 is shown below in Figure 4-2.[46]

Figure 4-2: Energy Market Mitigation Structural Test Failures



In Fall 2025, the total asset hours subject to mitigation totaled about 466,000 asset hours, in which 28,000 asset hours (6%) failed structural tests.[47] The frequency of structural test failures was higher than in Fall 2024, driven by a higher frequency of general threshold energy test failures. This type of structural test failure occurs when a committed generator is owned by a pivotal supplier, and there was a higher incidence of pivotal suppliers in Fall 2025 due to lower reserve margins caused by prolonged pumped-storage generator outages. Pivotal suppliers are discussed in more detail in section 4.1. Overall, asset hours of structural test failures represent a very small fraction of

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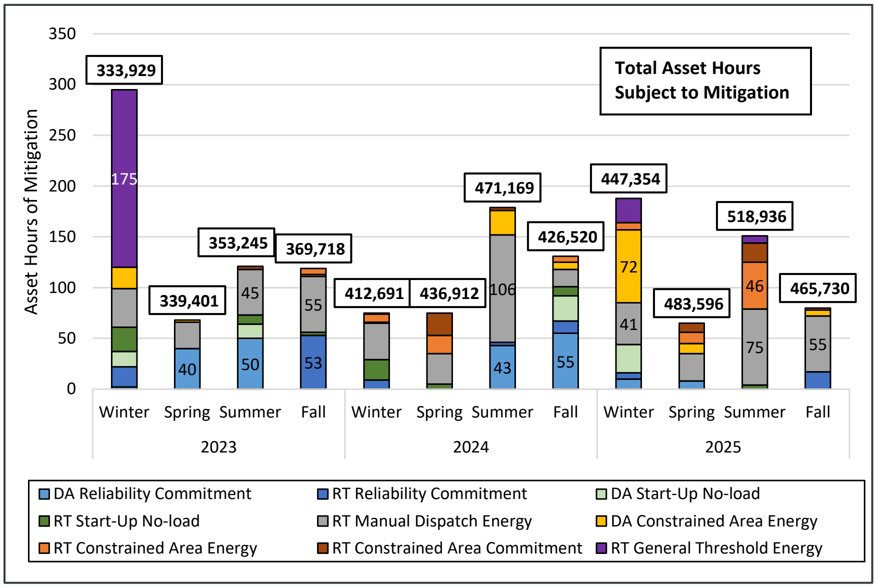
[46] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available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

[47] The asset hours subject to mitigation are estimated as a committed generator. Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

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 4-3 along with the total amount of asset hours subject to mitigation (white boxes).

Figure 4-3: Energy Market Mitigation Asset Hours



There were 80 mitigation asset hours in Fall 2025, lower than in Fall 2024.

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.[48] There were no day-ahead reliability commitments in Fall 2025. There were 17 asset hours of real-time reliability commitment mitigations impacting pondage units offering above their estimated opportunity cost.

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 very high uplift.[49] SUNL mitigations occur infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In Fall 2025, there were no instances of SUNL mitigations.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained area mitigation follows the incidence of transmission congestion and import-constrained areas within

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[48] 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. For more on applicability, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market 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.

[49] 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).

New England. In Fall 2025, structural test failures totaled 3,861 asset hours spread across several load zones. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. In Fall 2025, there were eight asset hours of constrained area mitigation, four of which occurred in the day-ahead market on September 9 in Maine. The remaining mitigations occurred in Vermont when the Northwest Vermont constraint bound on October 27 and 28.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs the least frequently of all mitigation types. Across the reporting period, an average of roughly 15,000 asset hours of pivotal supplier energy offers were subject to GTE mitigation each quarter; mitigation has occurred for only 206 asset hours, 175 of which occurred in Winter 2023. There were no GTE mitigations in Fall 2025.

Manual dispatch energy (MDE) mitigation: The ISO will utilize manual dispatch points for flexible resources to address short-term issues on the transmission grid. As a result, gas- or dual fuel-fired generators receive manual dispatches most often, accounting for 80% of the 261 asset hours of manual dispatch in Fall 2025. Due to a relatively tight conduct test, manual dispatch energy mitigation typically occurs more frequently than other mitigation types. There were 55 asset hours of MDE mitigation in Fall 2025.

Section 5
Forward Markets

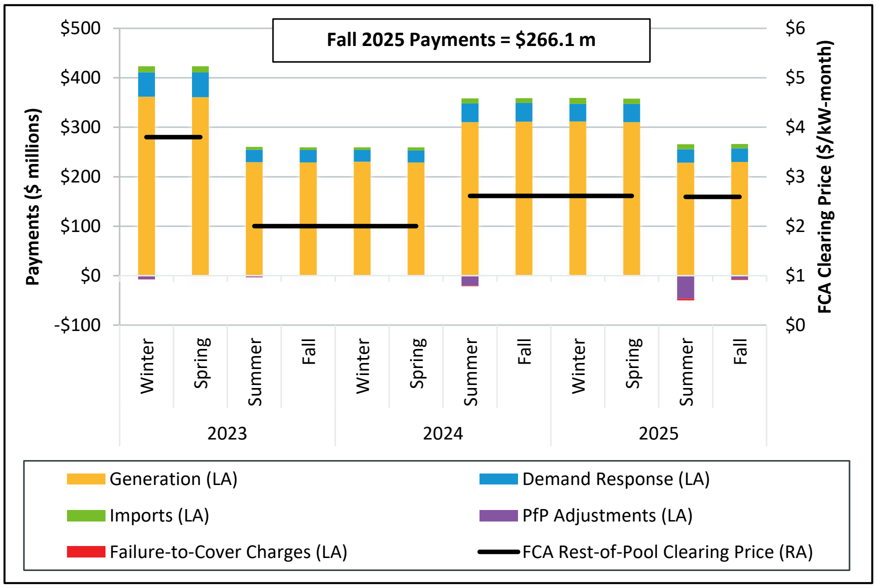
This section covers activity in the Forward Capacity Market (FCM) and Financial Transmission Rights (FTRs).

5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Fall 2025 started on June 1, 2025, and will end on May 31, 2026. The corresponding Forward Capacity Auction (FCA 16) cleared at $2.59/kW-month for the rest-of-pool capacity zone, with prices relatively unchanged from FCA 15 ($2.61/kW-month). The auction cleared with 32,810 MW of Capacity Supply Obligation (CSO), representing a surplus of more than 1,000 MW over the Net Installed Capacity Requirement (Net ICR; 31,645 MW). FCA 16 cleared with modest price separation; the import-constrained Southeast New England capacity prices cleared at $2.64/kW-month, while the export-constrained Northern New England and Maine capacity zones cleared at $2.53/kW-month. While new capacity additions totaled less than 600 MW for FCA 16, solar, demand response, and battery resources comprised the largest shares of new capacity.

Total FCM payments, as well as the clearing prices for Winter 2023 through Fall 2025, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, light blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance (PfP) adjustments, while the red bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Market Payments



Capacity payments totaled $266.1 million in Fall 2025, down 26% from Fall 2024. Capacity payments declined despite similar rest-of-pool clearing prices between FCA 15 and FCA 16, driven by a decrease in cleared capacity in FCA 16 and less upward price separation in the import-constrained Southeast New England capacity zone. As a result of the November 23 PfP event, under-performing capacity resources transferred $7.3 million to over-performing non-capacity resources.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the primary auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Fall 2025 are detailed in Table 5-1 below alongside primary FCA outcomes.

Table 5-1: Primary and Secondary Market Outcomes

				Capacity Zone/Interface Prices ($/kW-mo)				
FCA # (Commitment Period)	**Auction Type**	**Period**	**Cleared MW***	**Rest-of-Pool****	**Maine**	**New Brunswick**	**Northern New England**	**Southeastern New England**
FCA 16 (2025-2026)	Primary	12-month	32,810	2.59	2.53	2.53	2.53	2.64
	Monthly Reconfiguration	Nov-25	486	1.22	1.22	1.22	1.22	1.22
	Monthly Bilateral	Nov-25	253	4.73				
	Monthly Reconfiguration	Dec-25	932	4.50	4.50	4.50	4.50	4.50
	Monthly Bilateral	Dec-25	253	4.73				
	Monthly Reconfiguration	Jan-26	956	5.50	5.50	5.50	5.50	5.50
	Monthly Bilateral	Jan-26	263	4.57				

**represents cleared supply/demand*

***bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions (MRAs) occurred in Fall 2025, spanning delivery months November 2025 through January 2026. The November 2025 MRA cleared 486 MW at $1.22/kW-mo, marking a lower clearing price than the primary auction. The December 2025 and January 2026 auctions each cleared over 900 MW at $4.50/kW-mo and $5.50/kW-mo, respectively. The higher activity and clearing prices in December and January reflect tighter supply and demand than in November 2025. These outcomes may reflect higher perceived risk of shortage events during the winter season.

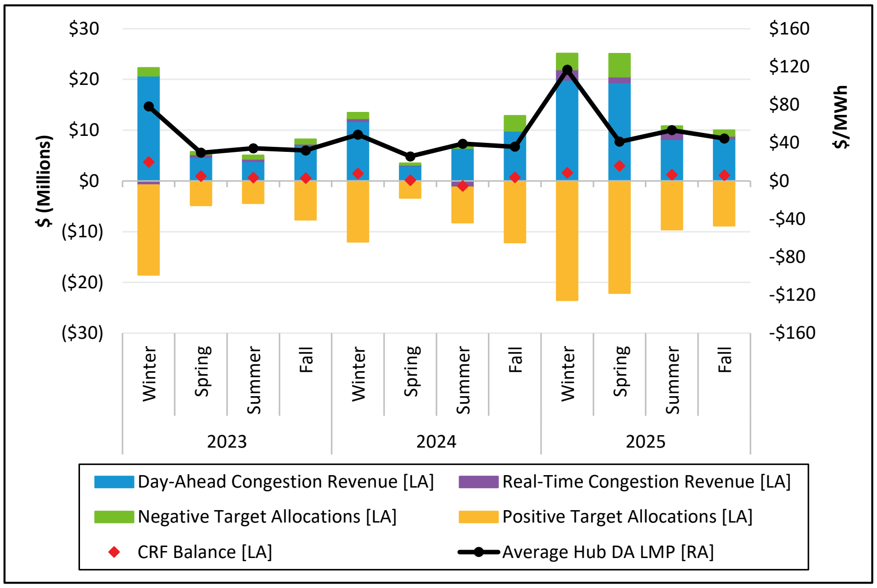
5.2 Financial Transmission Rights

This section of the report discusses Financial Transmission Rights (FTRs), which are financial instruments that settle based on the transmission congestion that occurs in the day-ahead energy market. The credits associated with holding an FTR are referred to as positive target allocations, and the revenue used to pay them comes from three sources:

1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
3) the revenue associated with transmission congestion in the real-time market.

Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[50, 51] This figure also depicts the quarterly average day-ahead Hub LMP.[52]

Figure 5-2: Congestion Revenue, Target Allocations, and Day-Ahead LMP by Quarter



Day-ahead congestion revenue amounted to $8.2 million in Fall 2025, down from $9.9 million in Fall 2024. Congestion revenue was similar to Summer 2025 following both similar system conditions and day-ahead LMPs. Positive target allocations totaled $8.8 million. Real-time congestion revenue ($0.6 million) and negative target allocations ($1.1 million) more than compensated for the deficit between day-ahead congestion revenue and positive target allocations. Consequently, FTRs were fully funded throughout the fall.

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[50] The CRF balances depicted are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + |Negative\ Target\ Allocations|) - Positive\ Target\ Allocations$ and do not include any adjustments (e.g., surplus interest, FTR capping).

[51] Figure 5-2 depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

[52] The average quarterly day-ahead Hub LMP is measured on the right axis (“RA”), while all the other values are measured on the left axis (“LA”).