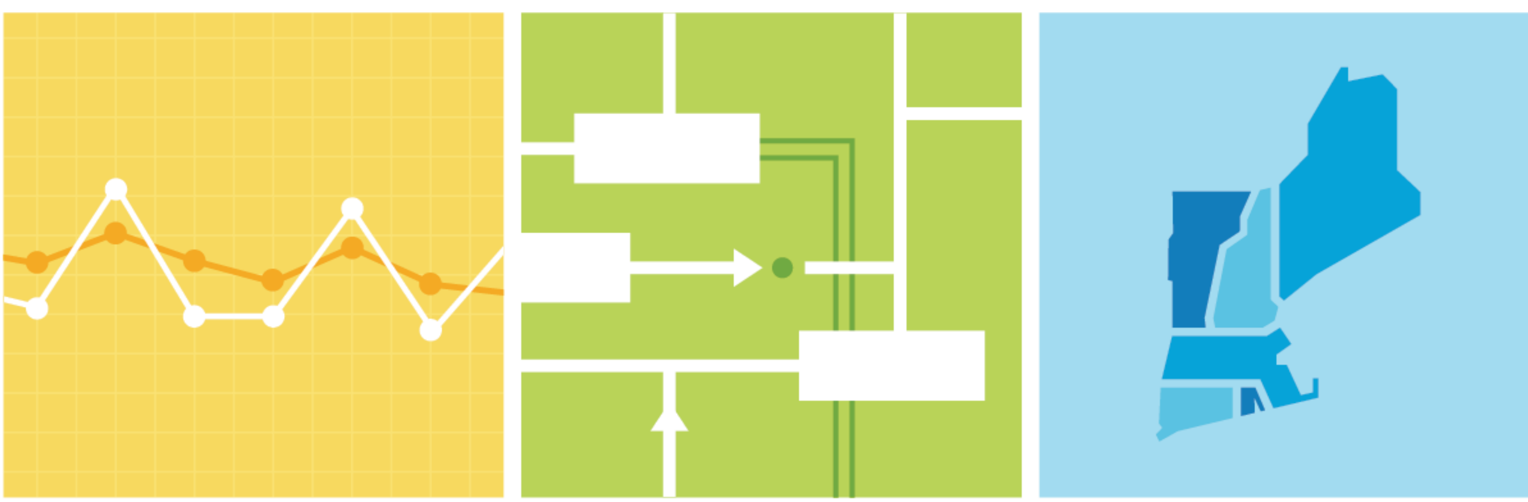
Winter 2025
Quarterly Markets Report

By ISO New England's Internal Market Monitor

JUNE 4, 2025



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Preface

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 the *ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3* (the "Tariff"), Section I, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

[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 Winter 2025 (December 1, 2024 through February 28, 2025).[3]

Winter Assessment: Although New England weather was consistently cold in Winter 2025, there were no significant reliability events, system events, or fuel availability issues in the region. The average hourly temperature for the season was the coldest of any winter since 2015, resulting in relatively high LNG sendout and oil inventory depletion. Below are highlights of the supply mix, fuel markets, and other winter outcomes.

- Winter 2025 saw the highest LMPs of all winter seasons since 2014.
- Average oil generation reached its highest level since Winter 2022, as higher-than-average oil consumption continued well into February while continued cold temperatures put upward pressure on gas costs.
- Total liquified natural gas (LNG) injections doubled from Winter 2024, totaling 22 million Dth.
- The spread between average fuel price adjustment (FPA) requests and settled index prices decreased compared to the prior winter, largely due to increased LNG sendout on cold days.
- No significant mitigation events occurred during this winter.
- Energy market opportunity cost (EMOC) estimates for oil-fired generators were non-zero on almost one-third of days, although EMOCs did not likely impact energy prices.

Inventoried Energy Program: This was the second winter of the Inventoried Energy Program (IEP). The total cost of the IEP during Winter 2025 was $78 million, similar to Winter 2024 and about 2% of total wholesale market costs.

In our assessment of the IEP, we found the following:

- IEP did not likely provide significant incremental energy security benefits to the region, and we do not support continuing the IEP.
- Oil inventories at the beginning of this winter were up from Winter 2023, the year prior to IEP implementation, by 10%, despite less favorable forward winter prices, with the increase attributable to resources in the IEP. Oil generation was similar to Winter 2023, but generators replenished only 56% of the burned inventory, compared with 112% in Winter 2023.
- The equivalent of 4,900 MW (352 GWh) of natural-gas backed generation participated in IEP, although it is unclear how much of this was incremental or directly attributable to the program.
- Program costs totaled $78.4 million (~2% of wholesale market costs), which were similar to the first year in the program.

[3] In Quarterly Markets Reports, outcomes are reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

- The impacts of IEP on energy prices were likely small, as EMOCs produced as a result of IEP did not produce any significant incremental changes to unit commitment or dispatch.
- The ISO intends to address the underlying objectives of the IEP through the Resource Capacity Accreditation (RCA) proposal. The RCA aims to accredit and compensate resources based on their reliability contributions to resource adequacy, thereby strengthening incentives to ensure energy availability.

Wholesale Costs: The total estimated wholesale market cost of electricity was $4.5 billion, up 116% from $2.09 billion in Winter 2024. The increase was driven by higher energy and capacity costs.

Energy costs were $4.03 billion ($126/MWh) in Winter 2025, up 147% on Winter 2024 costs, driven by a substantial increase in natural gas prices (up 179%). The upward pressure of high natural gas prices on LMPs was partially offset by other fuel types setting price during the tightest gas system conditions.

Capacity costs totaled $359 million, up 39% from last winter. Beginning in Summer 2024, higher capacity clearing prices from the fifteenth Forward Capacity Auction (FCA 15) led to higher wholesale costs relative to the previous FCA. During Winter 2024, the capacity payment rate for all new and existing resources was $2.00/kW-month. This year, the payment rate for new and existing resources increased to $2.61/kW-month due to a higher Net Installed Capacity Requirement (up by 780 MW) and a decrease in surplus capacity due to the retirement of the Mystic combined cycle generators.

Energy Prices: Day-ahead and real-time Hub prices averaged $116.73/MWh and $114.80/MWh respectively, up by $68-$70/MWh from Winter 2024.

- Natural gas prices averaged $13.58/MMBtu in Winter 2025, up 179% compared to $4.87/MMBtu during the prior Winter. The increase was due to colder weather and lower storage levels.
- The upward pressure of natural gas prices on LMPs was partially offset by additional oil generation and net imports compared to Winter 2024.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $16.0 million, up 73% from Winter 2024 due to higher energy prices. Despite the increase, NCPC payments represented just 0.4% of total wholesale energy costs in Winter 2025, a lower share than in the previous winter.

- Almost all NCPC (91%) was in the economic category, which includes payments to resources providing first-contingency protection and payments to resources operating below their economic dispatch point at the instruction of the ISO.
- Local second contingency payments ($0.7 million) were primarily driven by commitments in the day-ahead market.
- Local distribution payments totaled $0.5 million. Distribution payments typically occur in summer when loads are high, and also occurred in Winter 2025 due to the relatively high loads throughout the season.

Real-time Reserves: Real-time reserve payments totaled $2.6 million, a similar value to Winter 2024. Most reserve payments went to resources providing TMSR (92%). This winter season had a higher frequency of TMSR prices than the prior two winters, reflecting tighter real-time system conditions on average, which resulted in the need to more frequently re-dispatch resources in order to create TMSR during the morning and evening ramps. Non-zero TMNSR and TMOR prices occurred less frequently, and average prices were lower in Winter 2025 than in prior winter seasons.

***Regulation*:** Total regulation market payments were $5.7 million, the same value as in Winter 2024. Though higher LMPs in Winter 2025 put upward pressure on regulation capacity prices, capacity offer prices were lower than in the previous winter, as lower cost alternative technology regulation resources continue to make up a larger share of the regulation mix.

Financial Transmission Rights: FTRs were fully funded in all months of Winter 2025, and most congestion-related totals moved in line with the day-ahead energy price. Day-ahead congestion revenue was $19.9 million in Winter 2025, up 70% relative to Winter 2024. Positive target allocations ($23.5 million) followed a similar pattern, increasing by 96% compared to Winter 2024. The New York – New England (NYNE) interface bound more frequently in Winter 2025, contributing to the increase in positive target allocations. Negative target allocations ($3.2 million) increased by 175% from their Winter 2024 level. Real-time congestion revenue remained in line with recent historical levels. At the end of February 2025, the congestion revenue fund had a surplus of $1.2 million.

Section 2
Assessment of Winter 2025 Market Issues

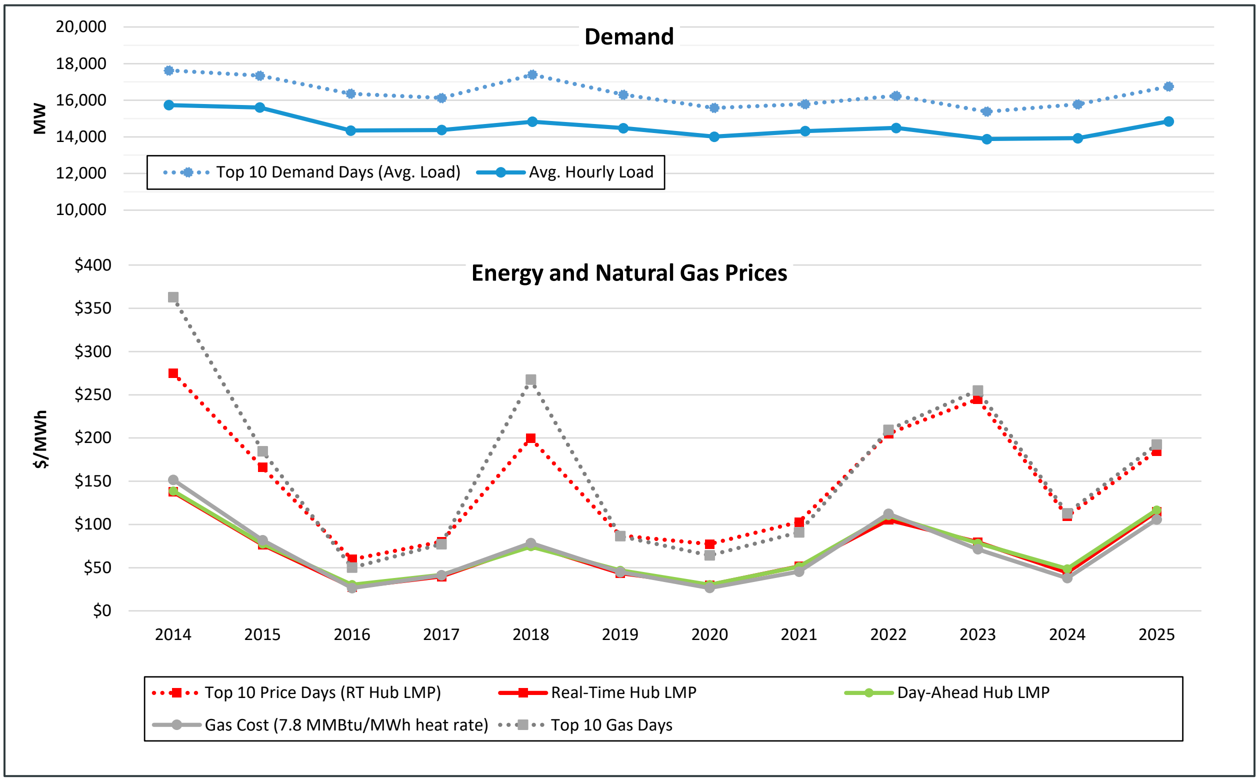
This section focuses on winter-specific issues in the New England markets. During winter in New England, increased heating demand for natural gas can cause pipelines to become constrained, giving rise to high natural gas prices. As temperatures fall, natural gas heating demand increases and natural gas-fired generators must compete for limited pipeline capacity.

Although the 2024/25 New England winter was cold, there were no significant reliability events, system events, or fuel availability issues in the region. Winter load reached the highest level since 2015 as average temperatures also fell to the lowest level in 10 years. While average temperatures were colder than normal in Winter 2025, there were relatively few extremely cold days. Consequently, peak loads were in-line with average levels over the past few years. High natural gas demand for heating and generation led to high natural gas prices relative to historic winter averages. Oil generators were economically competitive with gas generators in several high-demand periods, and stored oil inventory reached a three-year low at the end of the season. Winter 2025 was the second winter of the Inventoried Energy Program (IEP), an interim two-winter out-of-market mechanism to incentivize stored fuel. The total cost of the IEP program during Winter 2024 was $78 million, about 2% of total wholesale costs.

2.1 Market Drivers and Price Summary

Winter 2025 saw the lowest average temperatures of all winter seasons since at least 2016. To provide historical context, Figure 2-1 shows average LMPs and natural gas costs, along with peak demand, since 2014.

Figure 2-1: Winter LMPs, Natural Gas Costs[4], and Loads



Winter LMPs have varied widely between 2014 and 2025. Average day-ahead and real-time LMPs in Winter 2025 ($116.73/MWh and $114.80/MWh) were the highest since Winter 2014, but just above Winter 2022 averages. The average real-time LMP on the top ten high-priced days in Winter 2025 ($185/MWh) was lower than the Winter 2022 and 2023 values, reflecting the lack of extremely code days in Winter 2025. Average loads were at the highest value since Winter 2015, and load on the top ten demand days was the highest since Winter 2018, which saw a notable cold snap period.

Table 2-1 below shows average day-ahead and real-time LMPs over the past seven winters, along with standard deviation to illustrate LMP volatility.

[4] The IMM uses a heat rate of 7.8 MMBtu/MWh to represent standard-efficiency gas generators.

Table 2-1: Hub LMP Statistics For Past 7 Winters

Season	Day-Ahead LMP Avg.	Day-Ahead LMP Standard Dev.	Real-Time LMP Avg.	Real-Time LMP Standard Dev.
Winter 2019	$46.93	$23.82	$43.64	$27.74
Winter 2020	$30.32	$18.25	$29.97	$23.74
Winter 2021	$51.30	$27.42	$51.66	$31.84
Winter 2022	$110.34	$58.95	$105.48	$70.54
Winter 2023	$78.29	$63.49	$79.52	$95.12
Winter 2024	$48.66	$32.29	$44.39	$34.72
Winter 2025	$116.73	$49.10	$114.80	$60.64

Despite the higher average LMPs in Winter 2025, prices were less volatile than Winters 2022 and 2023. This illustrates how Winter 2025 saw lower temperatures and higher natural gas prices that persisted throughout the quarter, rather than distinct "cold snap" periods that resulted in outlier LMPs.

Temperatures averaged 28°F in Winter 2025, which was the coldest winter average temperature since 2015. Table 2-2, below, shows the number of days each winter with an average daily temperature less than 20 degrees Fahrenheit, a typical temperature in which we see oil prices rise above natural gas prices.

Table 2-2: Winter Temperature Statistics

Season	Number of Days Under 20 degrees Average Temperature	Maximum Number of Consecutive Days Under 20 Degrees Fahrenheit	Average Winter Temperature (degrees Fahrenheit)
Winter 2014	27	4	27
Winter 2015	33	9	26
Winter 2016	6	4	35
Winter 2017	5	3	33
Winter 2018	15	8	29
Winter 2019	8	3	30
Winter 2020	6	2	33
Winter 2021	5	3	31
Winter 2022	15	3	31
Winter 2023	5	2	35
Winter 2024	3	2	34
Winter 2025	13	6	28

While average temperatures reached a ten-year low, the number of days under 20 degrees was comparable to Winter 2022 and 2018. There was one stretch of six days (January 20-25) in which temperatures were under 20 degrees for an extended period and oil inventories were depleted. The lack of individual extremely cold days in 2025 led to unremarkable peak load conditions (19,639 MW).

2.2 Supply Mix, Fuel Inventory and Oil

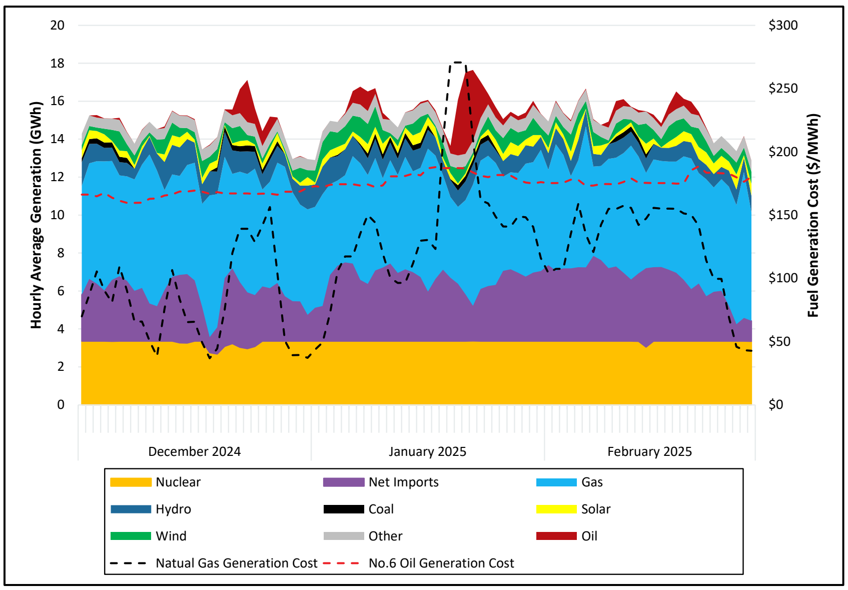
During winter months, limited natural gas availability can lead to reliability concerns for the delivery of wholesale electricity. To mitigate fuel uncertainty and inform effective operational planning, the ISO monitors the availability of generators' fuel oil supplies, and works with the natural gas pipelines in the region to understand potential gas system issues that might limit generator operations. In Winter 2025, despite colder temperatures there were no significant gas system issues.

The following subsections discuss the supply mix, fuel inventory, and the natural gas market, with a special focus on winter outcomes.

2.2.1 Supply Mix

High gas prices led to high generation costs in Winter 2025. While natural gas generation still comprised a large share of the supply mix, there was more oil generation in Winter 2025 than the prior two years. The relationship between natural gas prices and oil generation can be seen in Figure 2-2, which depicts the average daily price of natural gas and oil (right axis) and the average supply per hour by fuel type for each day in Winter 2025 (left axis).[5,6]

Figure 2-2: Real-Time Generation Obligation by Fuel Type and Gas/Oil Price



Including emissions costs, estimated natural gas generation costs averaged $116/MWh in Winter 2025.[7] High natural gas costs led to many periods when oil generation was economic, particularly on cold days when natural gas costs spiked. Significant amounts of oil generation occurred between

[5] Electricity generation equals native generation plus net imports. The "Other" category includes battery storage, landfill gas, methane, refuse, steam, wood, and demand response.

[6] The natural gas generation cost and no. 6 oil generation cost lines both include emissions costs, and represent the total $/MWh cost of generation from fuel costs and emission costs. These are estimates based on average efficiencies, emission rates, and estimated fuel costs. Therefore, some relatively efficient oil generation might have been in-merit even on a day when the estimated natural gas generation cost was lower than the estimated oil generation cost.

[7] The IMM uses a heat rate of 7.8 MMBtu/MWh to represent a standard efficiency natural gas generator. Emissions costs are included using standard emissions rate assumptions.

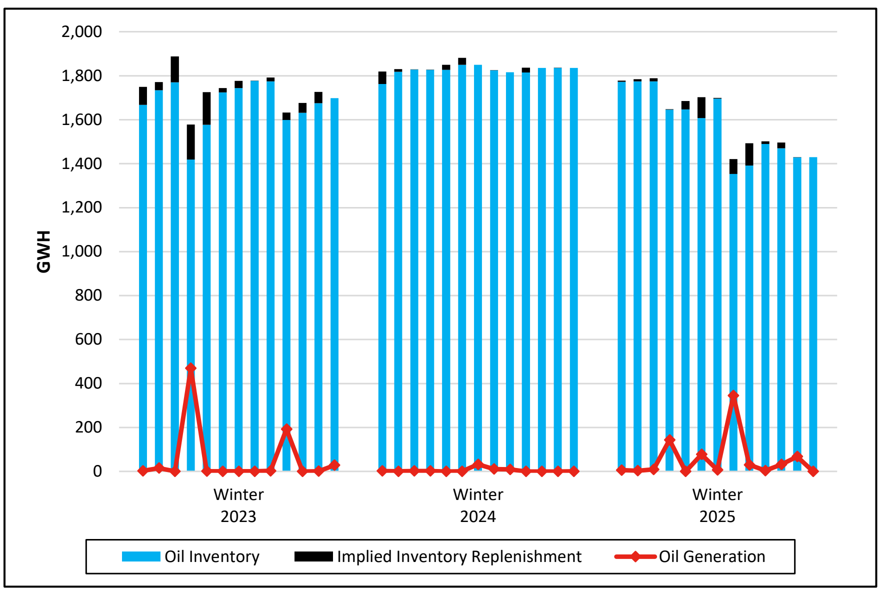
January 18 and January 22, when a cold snap pushed estimated natural gas generation costs above $200/MMBtu. Daily oil generation peaked at over 4,000 MW on January 21. Winter 2025 average oil generation reached its highest level since Winter 2022, as higher-than-average oil consumption continued well into February while continued cold temperatures put upward pressure on gas costs. The largest share of oil generation came from combined cycle units with dual-fuel capability that switched to oil when it was cheaper than natural gas.

2.2.2 Fuel Oil Inventory

Oil-fired generation provides both grid reliability and market flexibility during winter months when gas pipelines may become constrained. Stored oil inventories provide a measure of how much oil-fired generation is available to the system, which can be particularly important as there can also be constraints on the timing of replenishment.

Figure 2-3 below show's weekly-aggregated fuel oil inventory expressed in terms of GWh of oil capacity, and includes estimated oil inventory replenishments that occurred throughout the winter.[8]

Figure 2-3: Winter Fuel Oil Inventories



Oil inventories totaled 1,750 GWh at the beginning of Winter 2025, down slightly from Winter 2024 levels. Multiple periods of high oil generation reduced inventories, and the steepest drop in inventory occurred during the week of January 19-25 when oil generators consumed inventory to

[8] Oil Inventory data are collected by the ISO in weekly surveys. The IMM estimates daily inventories by subtracting oil generation from reported inventories between report dates. Inventories are reported in both gallons and GWh. For ease of interpretation, these inventories (and oil generation) are converted to days of potential generation at system total CSO for oil-fired generators. System total CSO is calculated as the sum of FCA cleared MW for oil resources and dual-fuel resources with oil registered as their primary fuel type. In Winter 2023-2025, the system total CSO for oil-fired generators was approximately 5,500 MW. For reference, Winter 2025 loads averaged 14,829 MW; at full output and with sufficient inventory, oil resources could comprise roughly 37% of average daily load when operating at capacity supply obligation. Oil generation in CSO-days represents actual oil generation as a proportion of daily CSO output. For example, one CSO-day of oil generation is equivalent to the generation produced by the oil fleet running at full CSO output for one day. Hourly oil generation might exceed total CSO because some resources might not clear their full capability in the FCA.

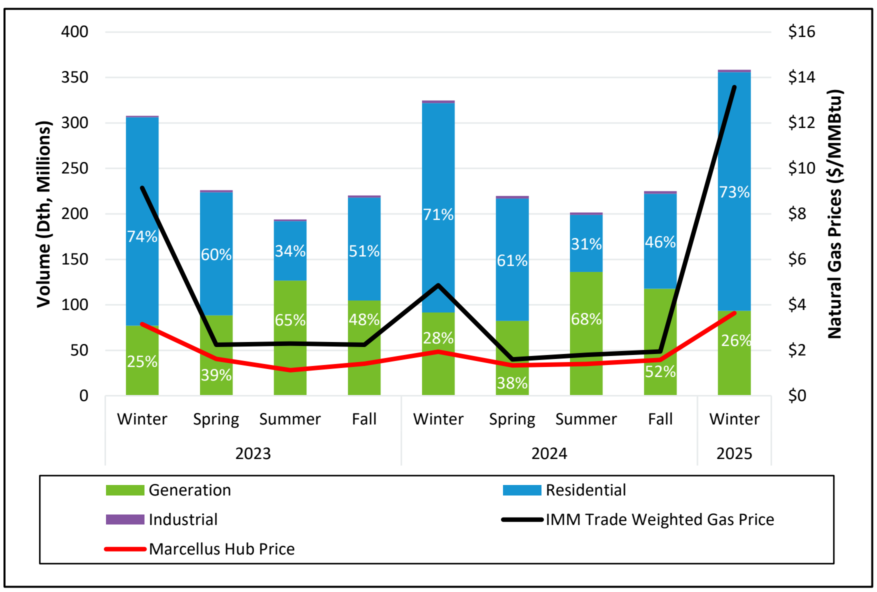
generate 350 GWh. Inventories fell to 1,350 GWh during this period. Stations replenished 210 GWh of oil inventory following this drop, but replenishments were offset by continued generation in February. Inventories at the end of the season totaled 1,430 GWh.

While the above analysis aggregates all oil generators, there is significant variation in inventories among stations.[9] The four stations with the most inventory accounted for 46% of total inventories and 24% of generating capacity at stations with stored oil capability.[10] While oil inventory was less concentrated in Winter 2025 than the prior two years, concentration of oil inventories in a few stations limits potential generation in extended oil-reliance scenarios. Additionally, many New England oil units are relatively old and at risk of retirement.[11] Upcoming unit retirements among high-inventory stations have the potential to affect 9% of Winter 2025 oil inventories.

2.2.3 Natural Gas Usage and LNG Supply

As temperatures fall in the winter months, residential heating demand increases and natural gas-fired generators must compete for limited pipeline capacity. The volume of gas demand by sector, alongside the average quarterly New England and Marcellus Hub natural gas prices, are shown in Figure 2-4 below.[12]

Figure 2-4: Natural Gas Demand by Sector



Total gas pipeline demand reached nearly 360 million MMBtu in Winter 2025, marking the highest level of gas demand in over 10 years. The increase was driven both by high residential demand for gas heating and high generation demand for electric heating. While generation demand fell as a share of total pipeline demand, it increased slightly in absolute terms to 93 million MMBtu from 92

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[9] Oil stations are groups of generating units that share the same oil inventory.

[10] Station oil output capability is measured here as the sum of the units' seasonal claimed capability (SCC).

[11] For more information on the potential retirements of oil units, see https://www.iso-ne.com/about/where-we-are-going/power-plant-retirements.

[12] Natural gas demand from the industrial sector is shown, but the sector only procures around 1% of gas demand in every quarter. All natural gas demand and LNG sendout data are sourced from *Wood Mackenzie*, available at https://www.woodmac.com/.

million MMBtu in Winter 2024. The high level of pipeline demand contributed to relatively constrained conditions and divergence at high prices between New England and hub gas prices.

Elevated natural gas demand occurred on a national level in Winter 2025. High natural gas demand led to price spikes at hubs in mid-January and mid-February, and national natural gas storage levels fell from above five-year averages at the beginning of winter to below five-year averages.[13] Northeast gas pipeline constraints extended beyond New England in Winter 2025 as price separation occurred in New York on several days. While New England is downstream from New York and typically experiences higher gas prices, New York gas prices were significantly higher than New England for six days in January, reaching above $97/MMBtu.[14] Discussed below, LNG injections into the New England gas system may have relieved pipeline congestion and reduced exposure to more extreme price volatility.

Physical Gas Pipeline Utilization and Pipeline Margins needed for Energy Reserves

New England natural gas supply is physically limited by pipeline capacity.[15] Gas generators compete with residential customers for limited pipeline capacity. This may lead to gas supply sufficiency concerns in winter months, when the gas generation fleet faces both high demand to meet high loads and limited capacity due to strong residential demand for heating. Furthermore, gas generators with operating reserve designations rely on additional unused gas availability in pipelines to support their reserve designations. Total gas pipeline usage (residential, industrial, and generation demand) and the estimated incremental pipeline capacity needed to support gas generator operating reserve designations in Winter 2025 are shown in Figure 2-5, below.[16,17] For context, the red portion of the chart shows the upper range and maximum of historic observed pipeline demand, and the orange line shows daily LNG injections.[18,19]

[13] For more information on national natural gas inventories in Winter 2025, see the EIA article *Recent cold snap results in fourth-largest withdrawal from underground natural gas storage*, available at https://www.eia.gov/todayinenergy/detail.php?id=64524. While New England does not have underground natural gas storage, trends in national underground storage affect gas pipeline prices.

[14] See the EIA *Natural Gas Weekly Update* for week ending January 22, available at https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2025/01_23/.

[15] LNG injections can provide additional natural gas supply beyond upstream pipeline capacity. This analysis considers natural gas deliveries at a daily level, where deliveries are sourced from either gas pipelines or LNG injections.

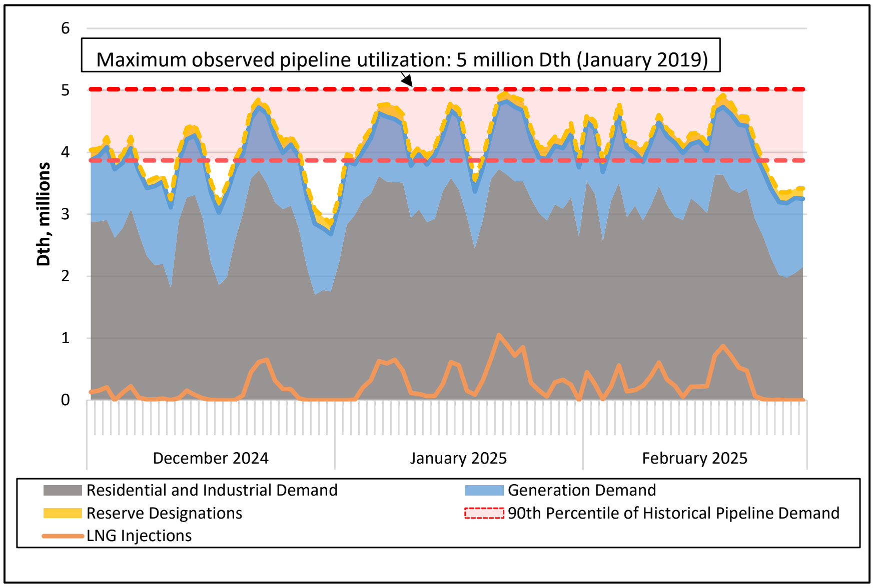
[16] Residential, industrial, and generation demand data is sourced from Wood Mackenzie.

[17] Incremental pipeline capacity needed to support reserve designations is estimated using generation (MW) and heat rate (MMBtu/MWh) data. The calculation includes the estimated gas needed to turn all operating reserves (MW) from gas-fired generators into energy, and the estimated gas for online dual-fuel generators according to their incremental fuel mix. Gas units with offline reserve designations are included: for each continuous period during which an offline gas unit provides reserves, the calculation includes the estimated gas needed to operate the generator once at its EcoMin limit for its minimum run time. Offline reserve designations to dual-fuel units are not included under the assumption that such units could start on oil if needed.

[18] The historic period used to calculate the historic range spans December 2013 to November 2024. Estimated incremental reserves are not included in this calculation.

[19] This figure relies on historic observed natural gas deliveries to estimate total pipeline capacity. Daily available pipeline capacity might exceed nominal nameplate capacity if line pack is present in gas pipelines. This figure does not account for daily line conditions or other factors that might influence daily pipeline capacity, such as compressor outages.

Figure 2-6: Pipeline Demand vs. Historic Utilization



High natural gas prices indicated that gas was relatively scarce in Winter 2025. Generation demand accounted for roughly a quarter of total pipeline demand. Including estimated gas margins needed to meet reserve designations, there were 67 days in Winter 2024 (~75% of days) during which pipeline deliveries were above the 90th percentile of historic deliveries, illustrating relatively high demand due to cold conditions. Incremental gas supply needed to support reserve designations averaged 15% of generation demand. Pipeline demand (including margins to support reserves) peaked around observed historical maximums, at just under 5 million MMBtu on January 22.

LNG Supply

Liquefied natural gas (LNG) provides another source of natural gas delivery into New England pipelines, and can be helpful in providing counterflow when pipelines are constrained from west to east, increasing the supply of natural gas available to gas-fired generators. The volume of injections (sendout) into the interstate pipelines from the St. John (formerly Canaport), Everett (Distrigas), and Excelerate LNG facilities for the past three years is illustrated in Figure 2-5 below.[20] The lines (right axis) show New England gas prices, the forward prices for LNG contracts for Northwest Europe LNG, and average Algonquin Citygates (ALG) futures prices two months before delivery.[21]

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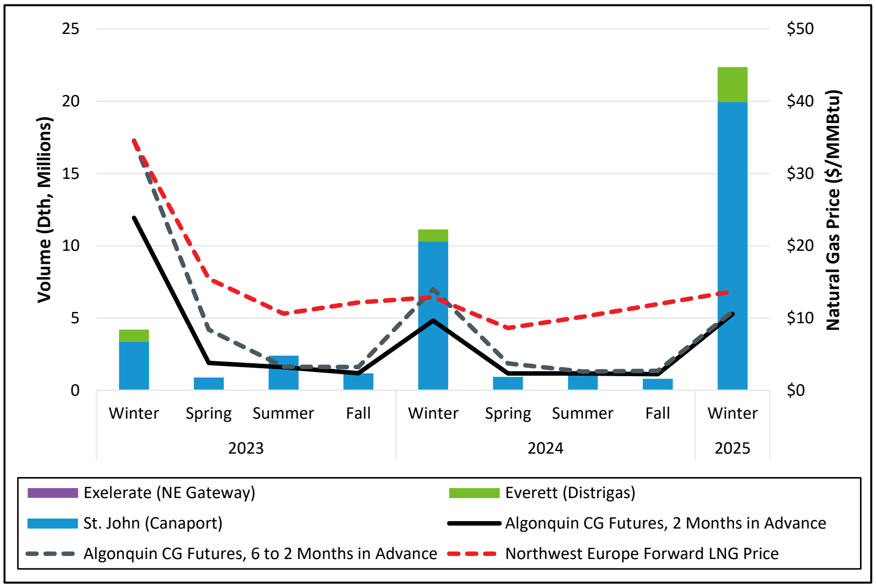
[20] The Saint John LNG facility is located in New Brunswick, Canada but delivers natural gas into New England via the Maritimes & Northeast pipeline. The volume from the Everett (Distrigas) represents flows from the facility into the interstate gas pipelines. Other New England LNG facilities include the inactive Neptune LNG deepwater port, and the newly-active 0.02 Bcf/d Northeast Energy Center LNG Terminal in Charlton, Massachusetts, for which data is not available. For more information on the terminal, see the *Winter Energy Market and Electric Reliability Assessment* published by the Federal Energy Regulatory Commission, available at https://www.ferc.gov/sites/default/files/2024-11/Winter%20Assessment%202024-2025%20Long%20Version.pdf.

[21] LNG sendout does not include LNG burned by the Mystic generators attached to the Everett LNG terminal. Future LNG prices are two-month forward prices provided by the Argus Media Group. Algonquin Citygates future prices are provided by the Intercontinental Exchange for the corresponding forward time period. Average prices by delivery month are calculated for trading days two months in advance of delivery, then aggregated to the season level through taking averages of monthly values within the season weighted by number of days.

Figure 2-5: LNG Sendout by Facility



LNG sendout roughly doubled from Winter 2024, totaling 22 million Dth. This sendout is equivalent to 1,300 MW per hour of standard efficiency gas generation for the winter.[22] LNG prices averaged $14/MMBtu in the months leading up to Winter 2025. The highest levels of daily LNG sendout occurred in mid-January when both local and national gas demand spiked under freezing weather. Natural gas futures prices traded below final gas prices before the winter season, indicating that natural gas was more scarce than expected in Winter 2025.

2.3 Impact of Natural Gas Prices on Energy Market Reference Levels and Prices

In New England, limited gas pipeline infrastructure, coupled with the absence of local natural gas deposits, can lead to procurement challenges for operators of natural gas-fired generators.[23] Many generators rely on short-term purchases, including next-day and same-day procurement.[24] As natural gas prices increase, purchases of LNG can increase supply and provide counterflow to alleviate pipeline constraints. Therefore, on days when gas pipelines are constrained, some Fuel-Price Adjustments (FPAs) may be based on LNG prices; these adjustments will be reflected in energy offers.

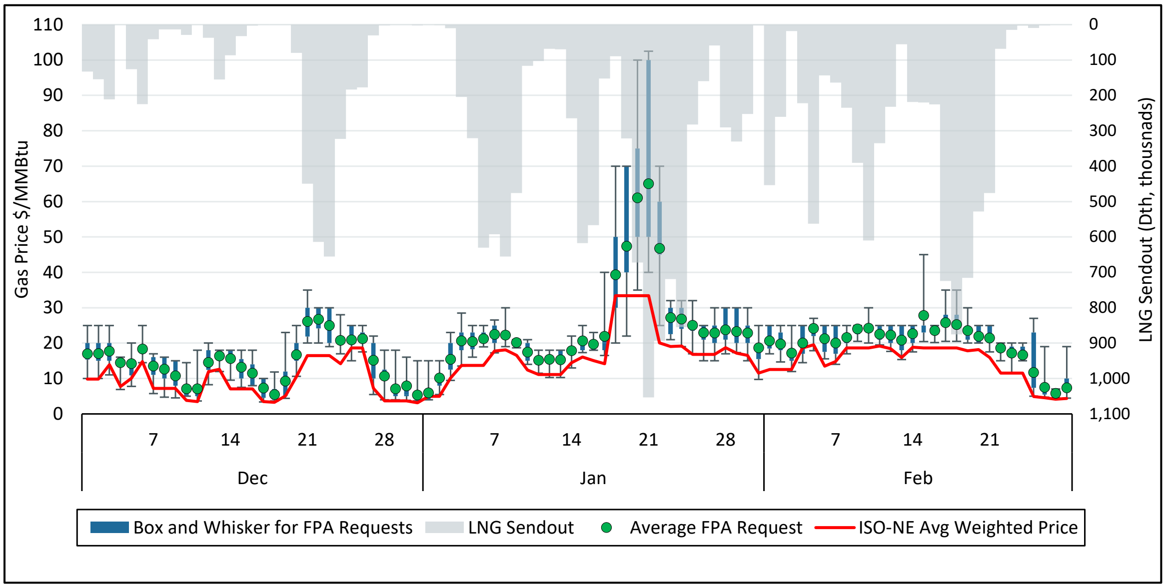
[22] The IMM uses a heat rate of 7.8 MMBtu/MWh to represent standard-efficiency gas generators.

[23] Pipelines in New England include Portland Natural Gas, Tennessee Gas, Algonquin, Iroquois, and Maritimes and Northeast. Additionally, there are three operational LNG import facilities that inject gas into New England: Excelerate, Saint John (formally Canaport), and Everett (Distrigas).

[24] See the ISO's *Natural Gas Infrastructure Constraints* information page, available at https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

We compare the range of FPA requested prices (a box and whisker chart) to gas index prices in Figure 2-6 below. The figure also illustrates the relationship between the gas index price and LNG injections.[25,26]

Figure 2-6: FPA Requests and Average Gas-Weighted Prices



Increased LNG sendout to New England (gray bars) lines up with periods with the highest index prices and FPA requests, notably January 18-24. During this period the gas system experienced high natural gas demand, and participants faced low trading volumes on exchanges and greater pricing and procurement uncertainty.

As mentioned above, in Section 2.2.3, LNG shipments are scheduled months in advance so, at times, LNG has to be sold to make room for incoming scheduled shipments. When prices were high during January 18-24, LNG suppliers capitalized on favorable conditions to sell LNG, compared to less advantageous circumstances leading up to January 18-24. Notably, LNG injections were equivalent to most or all of gas consumed for electricity generation on a few days in this period.

Impact of High Natural Gas Prices on Energy Market Outcomes

When system conditions are tight, we monitor pivotal suppliers in the energy market to ensure they do not withhold supply in an effort to drive up energy prices. When New England's natural gas pipelines operate near full capacity, there may be an analogous opportunity for gas suppliers to exercise market power. However, we do not have the data to evaluate this hypothesis. What we observe through daily monitoring and FPA consultations is that when the pipelines operate at or near full capacity, and trading on exchanges is limited, there are large spreads in the FPA requests

[25] There are no volumes associated with FPA requests, so the green dot represents a simple average for the day. The box and whisker represents the daily high, low, and inter-quartile range of FPA requests.

[26] The following explains the box and whisker plot from top to bottom. The top of horizontal marker represents the maximum FPA request. The top of the blue bar is the 75th percentile. The green dot is the average, or 50th percentile. The bottom of the blue bar is the 25th percentile, which means the height of the blue bar shows the inter-quartile range. The bottom horizontal marker represents the minimum FPA request.

submitted by participants, even on the same pipelines. This is indicative that there may be inefficient gas market outcomes driving inflated prices and payments in the energy market.

We estimated the impact of FPA-based offers on the energy market for days with especially tight gas-market conditions.

Figure 2-7 below summarizes the analysis of FPA-based offer impacts on LMPs between December 1, 2024 and February 28, 2025.[27] The black line, charted on the left axis, shows the Hub LMP. Two IMM-estimated values also share the left axis:

- First, the *Offer*s (gray bars): the top of the darker gray bars show the average offer prices of generator segments that reflect approved FPAs. The bottom of the darker gray bars show an estimated average of the same segment prices recalculated to reflect the market index price. The difference (the bar height) is the average markup between FPA-based offers and the recalculated offers at index. Because this year's analysis shows an expanded period due to persistent FPA impacts, an additional lighter gray bar is also included. The bottom of the lighter gray bars show the lowest prices of the recalculated (i.e., index-based) offers in each interval. This bar is included to better explain LMP impacts when the daily average index-based prices exceed the LMP.

- Second, the *Counterfactual LMP* (red line): shows the estimated LMP if the offer segments that reflect approved FPAs were instead based on the index price. Instances when the red line dips below the black line indicate that high-FPA offers impacted energy prices when compared to offers at index. In other words, if generators offered at index, market prices would have been lower.[28] Finally, the *Uneconomic Output* (black bars): on the right axis, shows an estimate of additional dispatched energy from the segments reflecting approved FPAs if the offer segments were priced at index, providing an indication of the quantity of energy that was "pushed out-of-merit" by an FPA.

[27] This metric shows real-time LMPs and the estimated impact of FPA-based offers on LMPs. We do not consider the LMP impacts of generation that was not committed due to high FPAs (i.e. only committed but undispatched generation is included) in this analysis due to the complexities of the commitment optimization and the resulting impacts on LMPs. This could result in estimated impacts lower than actual impacts. We estimate only 6 MW of uncommitted energy that is out-of-the-money due to FPA requests. These estimates are interval-level and do not account for generator constraints and will, therefore, overstate the uncommitted MWs.

[28] When the red line is hidden by the black line, we did not estimate any impact on LMP from FPA-based offers during the hour.

Figure 2-7: Real-Time FPA Price Impacts, December 1, 2024 – February 28, 2025

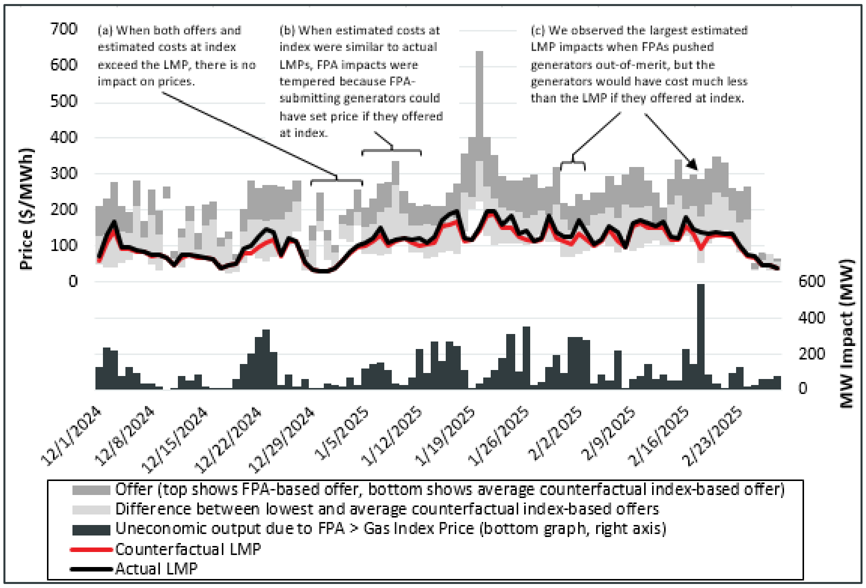


Figure 2-7 highlights a few key takeaways. First, the price impacts of FPAs were typically low. Over the entirety of the winter, FPAs impacted the average LMP by an estimated $9.78, or about 9%. Half of the days over the winter were impacted less than 5% from FPAs and 75% of days were less than 10%. This is because on most days, average offers based on both FPAs and the index price were above the LMP, so offers based on FPAs would not have been in-merit if they were offered at index.

Second, generally, we see impacts when the top of the dark gray bars are above the black line, the bottom of the lighter gray bar is far below the black line, and there were many offered MWs (black bars) that would have been in-merit if offered at index. On February 18, the LMP ($137/MWh) was about 33% higher than the estimated counterfactual LMP ($91) due to about 600 MW of energy offers that were out-of-merit at offered prices, but we estimated would have been in-merit if priced at index. On December 20-24, the average LMP ($121/MWh) was about 20% higher than the estimated counterfactual LMP ($97/MWh). Other periods of time that stand out are December 1-3 (14% increase), January 12-17 (12% increase) and January 24-February 3 (12% increase). During this time, the system was operating at an inelastic portion of the supply curve when load was slightly higher than forecast (i.e., the system was relatively tight).

2.4 Marginal Cost Reference Level Inputs

This section summarizes two inputs into marginal cost reference levels during Winter 2024. Accurate reference levels ensure that mitigation is applied appropriately when market participants have the opportunity to exercise market power, and attempt to do so by marking up their offers above cost. No noteworthy mitigation events occurred during this winter.

2.4.1 Energy Market Opportunity Cost Adjustments

Energy market reference levels include an energy market opportunity cost (EMOC) adder for resources that maintain oil inventory.[29] During cold weather events, the inclusion of opportunity costs in energy offers (and reference levels) enables the market to preserve limited fuel for hours when it is most economic to alleviate tight system conditions.

Every day, the IMM calculates generator-specific EMOC adders with a mixed-integer programming model. For a given forecast of LMPs and fuel prices, the model seeks to maximize an oil-fired generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and asset operational characteristics. Last winter, the model was updated to include opportunity costs related to the Inventoried Energy Program (IEP).

While the calculation of EMOCs is complicated and dependent on a number of variables (gas and oil price forecasts, fuel inventory levels, and generator characteristics), it is possible to develop a general sense of when EMOCs are likely to occur. Primarily, we should expect to see EMOCs for a generator when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to deplete their oil-fired inventory. This type of scenario would typically occur during an extended period of very cold weather when demand for natural gas is highest.

Last winter, due to the ample inventories of stored fuel and the relatively high price of oil to natural gas during the winter, no (non-zero) EMOCs were produced. This winter, ten different assets received a non-zero EMOC at some point during the Winter. At least one asset received an EMOC on 28 different days. However, we found that EMOCs incorporated into asset offers likely did not impact energy market prices.

In the day-ahead market, committed units with modeled EMOCs were generally offered on gas due to emissions or operational limitations and, therefore, did not incur any opportunity cost related to depleted oil inventory. In real-time, there were five commitments of units offering on oil with a modeled EMOC. These units appeared to reflect a portion of their EMOCs in their offers. However, only $7,000 in commitment-out-of-merit NCPC was paid to these units and there were no mitigations, making the slightly higher offers unimpactful for the committed generators.[30]

[29] This enhancement to reference levels, implemented in 2018, was motivated by concerns that, during sustained cold weather events, generators were unable to incorporate opportunity costs associated with the depletion of their limited fuel stock into their energy supply offers due to the risk of market power mitigation. Such an event arose during Winter 2018 - which resulted in ISO operators posturing oil-fired generators to conserve oil inventories.

[30] An EMOC can impact NCPC for a committed unit if the unit switched fuel due to an EMOC (decided to start up on gas rather than oil) and received NCPC payments at a higher cost. However, units offering on gas were generally constrained not by economics but by emission or operational limits, so the EMOC was not impactful. Additionally, there were no COOM NCPC payments for units committed on gas with modeled non-zero EMOCs.

Of the uncommitted units with modeled EMOCs, 6% were indexed to natural gas due to emissions or operational limitations. The remaining 94% of uncommitted assets were indexed to oil and reflected EMOCs, but were out of the money and would have been out-of-the-money even if EMOCs were excluded from marginal cost estimates (i.e., EMOCs pushed units from extra-marginal to more extra-marginal).

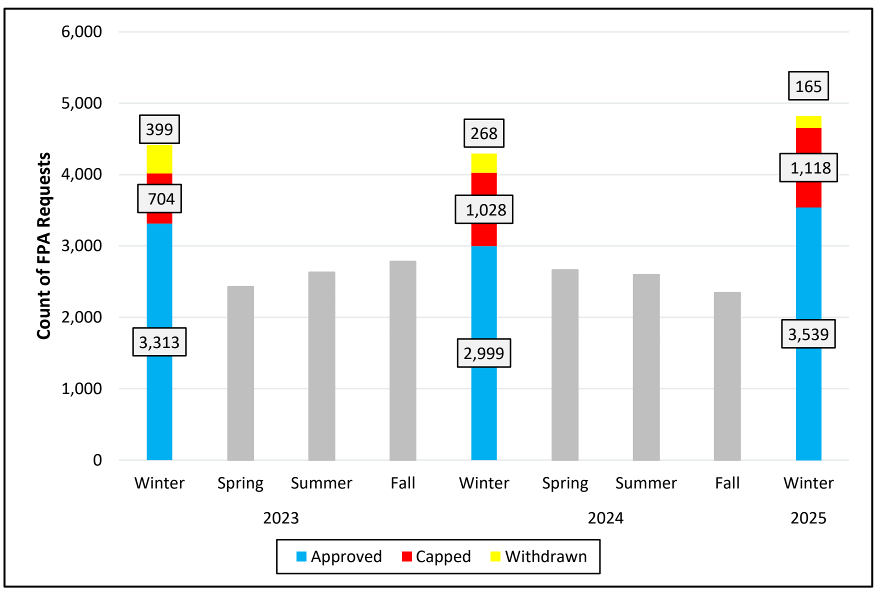
The LMP impact of committed but undispatched (or price-setting) generation with modeled EMOCs was also limited. There was only a total of 10 minutes in the real-time during the winter that we estimated an LMP impact from undispatched energy due to EMOC adders.

2.4.2 Fuel Price Adjustments

In this subsection, we provide an overview and analysis of Fuel Price Adjustment (FPA) requests for Winter 2025. Participants use FPAs to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index. As part of the FPA request assessment, we use a model to estimate a reasonable upper bound for natural gas prices ("FPA Limit").[31] For more details on how FPAs are processed, see *Appendix: Overview of FPA Process*, at the end of this report.

In Winter 2025, we received FPA requests from 21 participants for 51 generators, which is similar to Winter 2024. Figure 2-8 shows the number of FPA requests by season over the last few years.

Figure 2-8: FPA Requests, by Year, Season, and Status



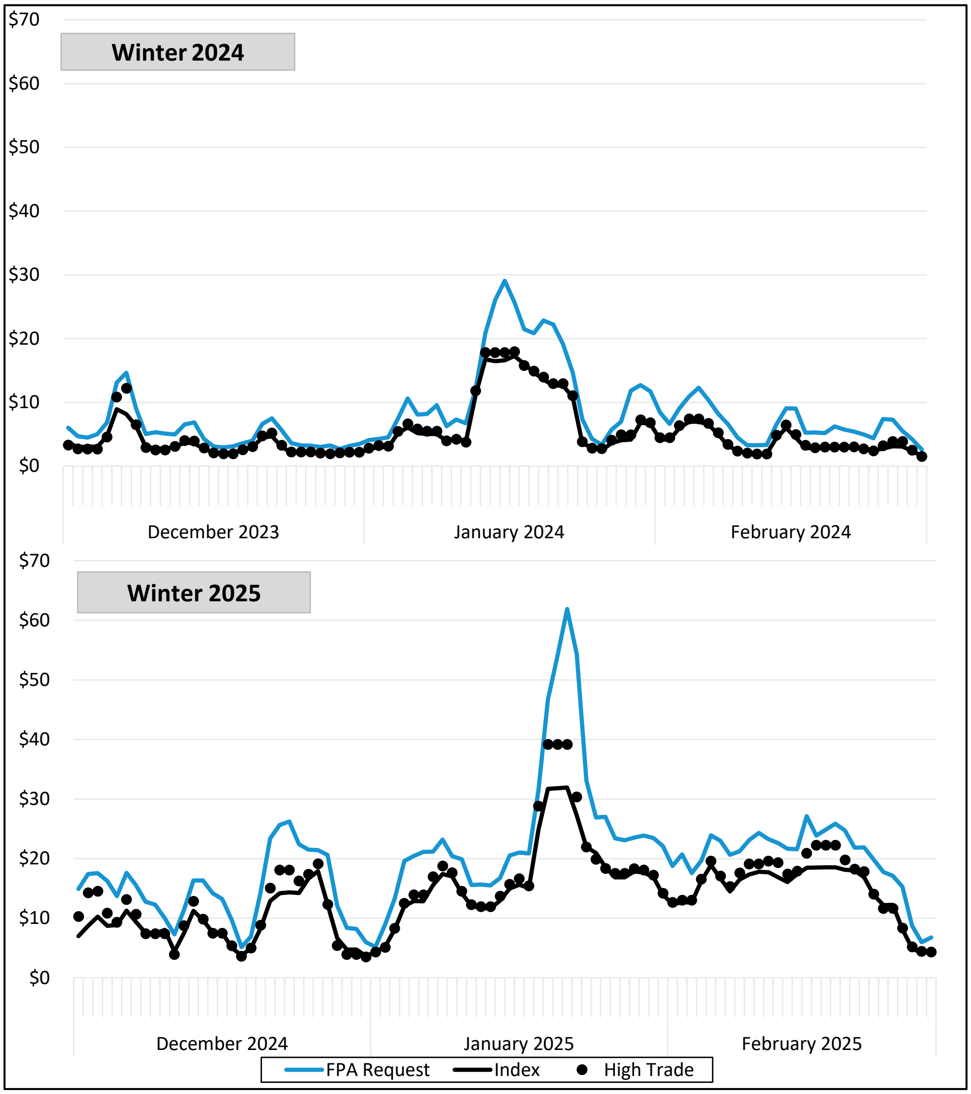
More than 4,800 FPA requests were processed during Winter 2025, an average of about 54 per day – a similar number to the prior winter. The number of FPA requests spikes in the winter compared to other seasons. This increase indicates both greater price volatility, price uncertainty, and

[31] Once processed, FPAs fall into one of three categories: approved, capped, or withdrawn. "Approved" indicates that the requested price was approved (either automatically or through IMM intervention) and used to update reference levels; "capped" indicates that the requested FPA price exceeded the FPA Limit (even after IMM intervention, if applicable); and "withdrawn" indicates that the FPA request was withdrawn prior to being effective (i.e., was not used as part of any mitigation conduct tests.)

additional factors discussed regarding Figure 2-9 below. Consistent with prior years, the majority of FPAs (~90%) were made for the day-ahead market.[32]

The following figure shows the average settled natural gas index price, average volume-weighted high-priced trade and average requested FPA price on a daily basis for the last two winter periods. FPA request data reflect simple averages because participants do not submit volume data (gas or energy) associated with the FPA. Subsequently, the hourly values roll into daily averages.

Figure 2-9: Average Index Price, High Trade, FPA Request, and Effective FPA



Although the average request in Winter 2025 ($19.96/MMBtu) was more than double the average request in Winter 2024 ($8.09/MMBtu), the percent spread between average FPA requests and settled index prices (48%) decreased compared to the prior winter (62%). This is largely due to the elevated natural gas demand in Winter 2025, and constraints in New England which led to higher settled index price ($13.48 vs. $4.99). In turn, FPA requests were closer to the settled index prices which themselves were high. As discussed in Section 2.1., LNG injections kept FPA requests closer

[32] Note that unless an FPA is withdrawn or overridden by another FPA, it will roll-over into the real-time market.

to the index price on days where non-LNG gas was limited. This reduced price volatility compared to Winter 2024. In the absence of LNG, participants submit trader quotes far above index prices, particularly on days with low liquidity on commodity exchanges.

2.4.3 Incorporating Fuel Price Variability in Reference Levels

As noted in our October 2023 memo to NEPOOL, we identified risks associated with FPAs and mitigation. FERC accepted a mitigation rule revisions for MW-dependent FPAs in November 2024. In Winter 2025, participants with an effective FPA offered 65% of their total capacity based on an implied fuel price below their FPA, providing an indication of the need for MW-dependent FPAs.[33] Under the current FPA submittal process, participants have limited ability to capture fuel price variability when updating their reference levels. While also providing additional flexibility to participants, the new submittal process for MW-dependent FPAs will improve our ability to monitor for potential instances of market manipulation and economic withholding.[34] We support an update to market rules so that participants can submit MW-dependent FPAs in order to better reflect fuel price variability in reference level segments consistent with offers.

2.5 Inventoried Energy Program

The Inventoried Energy Program (IEP) is a voluntary, interim program offered during Winter 2024 and Winter 2025. Following the retention of Mystic 8 and 9 to address fuel security reliability concerns, the ISO designed the IEP as an interim solution to compensate resources for providing secure energy benefits. The program sought to incent actions enhancing winter energy security and prevent the premature retirement of crucial resources through a technology-neutral compensation strategy.[35]

The program was intended to be simple enough for relatively fast design and implementation, allowing participants to anticipate potential revenues and make informed decisions about resource retirement prior to FCA 14. The IEP program has five components:

1. a two-settlement structure: participation in both the forward and spot components, or the spot component only,
2. a forward rate: payment of $79/MWh of inventoried energy sold forward,[36]
3. a spot rate: 1/10th of the forward rate, or $7.90/MWh—is applied to deviations between the inventoried energy sold forward and the inventory maintained following a trigger condition,
4. trigger condition: also known as an Inventoried Energy Day, is defined as a day when the average of the high and the low temperatures at Bradley International Airport in Windsor Locks, CT, is less than or equal to 17^{o}F,[37]

[33] See ISO Market Committee presentation *Revise Energy Offer Mitigation to Address FERC Show Cause Order: MW-Dependent Fuel Price Adjustment (FPA) Proposal* (April 9-10, 2024) by Andrew Withers, available at https://www.iso-ne.com/static-assets/documents/100010/a05_mc_2024_04_09_10_fpa_process_changes.pdf

[34] The ISO is planning to file this proposal with the Commission in the coming months. See: https://www.iso-ne.com/static-assets/documents/100011/a05_mc_2024_05_07_08_mw_dependent_fpa_presentation.pdf.

[35] See Inventoried Energy Program of ISO New England Inc., Docket No. ER19-1428-000 ("IEP Filing Letter") (March 25, 2019), pp. 5-6, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20190325-5091.

[36] Each participant can sell up to 72-hours of inventoried energy forward. Last winter, the payment rate was $92.51/MWh of inventoried energy sold forward and $9.25/MWh per spot MWh.

[37] A spot-only participant is treated as having a zero forward position and can therefore only earn positive IEP settlements.

5. a maximum duration: 72 hours' worth of inventoried energy.

In our assessment of the IEP, we found the following:

- Oil inventories at the beginning of this winter were similar to last year. The oil inventories at the beginning of Winter 2025 were up 10% from the year prior to IEP implementation despite less favorable forward winter prices, with the increase attributable to resources in the IEP.[38] However, oil replenishment was 50% lower than in Winter 2023 (the winter prior to IEP implementation), despite similar oil generation.
- The equivalent of 4,900 MW per hour of natural-gas backed generation participated in IEP, although it is unclear whether these resources procured additional fuel as a result of their participation in the program.
- Program costs totaled $78.4 million (~2% of wholesale market costs), which were similar to the first year of the program ($78.8 million).
- IEP did not appear to affect energy prices, as IEP-driven energy market opportunity costs did not impact units' commitment or dispatch incentives at the margin.
- The ISO intends to address the underlying objectives of the IEP through the Resource Capacity Accreditation (RCA) proposal. The RCA aims to accredit and compensate resources based on their reliability contributions to resource adequacy, thereby strengthening incentives to ensure energy availability.

2.5.1 Program Cost to Load

The overall cost of the IEP program in Winter 2024 was $78.4 million—driven almost entirely by $78.6 million of forward payments, as shown in Table 2-3 below. The market-wide average inventoried energy reported on five inventoried energy days this winter was less than 1% lower than the forward inventoried energy, resulting in about $250 thousand of spot charges.

Table 2-3: IEP Payments by Fuel Type ($ millions)

Fuel Type	Forward Payments	Spot Payments	Total Payments	2023-2024 Winter Total Payments
Oil	$48.50	($0.98)	$47.51	$52.50
Natural Gas	$20.37	$0.39	$20.76	$24.40[39]
Natural Gas/Oil	$8.11	$0.09	$8.19	
Refuse	$1.32	$0.03	$1.35	$1.70
Electric Storage	$0.32	$0.22	$0.54	$0.30
Demand Response	$0.00	$0.00	$0.00	$0.00
Total	**$78.61**	**($0.25)**	**$78.35**	**$78.80**

[38] Starting inventories in Winter 2024 and Winter 2025 were similar for both resources participating in IEP and non-participating resources.

[39] Last winter, Natural Gas/Oil forward payments were attributed to Natural Gas, while spot payments were attributed to Oil due to the specifics of the submissions related to dual fuel units. This winter, participants used a more dynamic methodology to opt into the forward component of the program so a similar methodology was not applied.

The total cost of the IEP program was very similar to the $78.8 million cost last winter. Although the forward rate was 15% lower in Winter 2025 ($79.00 vs. $92.51), enrollment in the forward component of the program was 18% higher, offsetting the lower rate. There were five inventoried energy days this winter (December 22-23 and January 20-22). Spot payments were positive during the December 22-23 inventoried energy days and negative on January 20-22. The negative payments on January 20-22 were driven by oil resources with depleted inventories—oil spot inventories were 8% lower than the forward position on average during these three days. Differences in participation are discussed below, in Section 2.5.2.

2.5.2 Participation in the IEP

Total participation in the IEP program was 1,164 GWh—similar to the 1,133 GWh of participation in Winter 2024. Despite similar overall participation, forward participation of 995 GWh was about 18% higher than the 884 GWh of forward participation in Winter 2024. Table 2-2-4, below, shows a summary of IEP participation.

Table 2-2-4: IEP Participation

Fuel Type	Winter 2023-2024	IEP Forward + Spot Qualified GWh	IEP Forward GWh	Percent of Qualified Sold Forward	Average Delivered on IEP Days GWh
Oil	753	707	614	87%	589
Natural Gas	345	295	258	87%	268
Natural Gas/Oil		123	103	83%	105
Refuse	22	24	17	68%	18
Electric Storage	14	14	4	29%	10
Demand Response	0	0	0		0
Total	**1,133**	**1,164**	**995**	**85%**	**989**

Overall, generators that elected to participate in the IEP qualified 1,164 GWh of inventoried energy, equivalent to about 16,164 MW per hour over three days. About 85% (995 GWh) of qualified inventoried energy was sold forward, equivalent to about 13,820 MW per hour.[40] Following the five inventoried energy days, participants reported an average of 989 GWh of inventoried energy (13,731 MW per hour for three days).

Oil-fired generators sold 614 GWh forward (87% of qualified inventoried energy), the most of any fuel type and 9% higher than in Winter 2024. In contrast with gas generators, which had to provide evidence of firm fuel arrangements to participate in the forward component of the program, oil generators could participate based on their tank size (rather than contracted oil inventory). Unlike Winter 2024, these generators did not deliver the full volume of their forward elections during spot inventory checks (25 GWh short, on average), although overall these resources delivered more total inventory than in Winter 2024 (589 GWh vs. 582 GWh). For context, 589 GWh is enough energy to produce about 8,200 MW per hour over a 72-hour period. The delivered inventoried energy generally decreased over the winter due to depleted oil inventories. On the first two inventoried

[40] Inventoried energy reflects the quantity of energy that can be provided in 72-hours based on each facility's fuel inventory and physical characteristics. Hourly MWs are equal to inventoried energy divided by 72 hours.

energy days, December 22-23, oil units provided 622 GWh of inventoried energy. The average inventoried energy on January 20-22 was 567 GWh.

Gas-fired generators qualified 352 GWh of inventoried energy, similar to Winter 2024 and corresponding to about 4,900 MW of firm gas per hour.[41] About 20% of the natural gas inventoried energy was backed by an LNG contract. The remaining gas contracts were backed by pipeline gas. Additionally, similar to the oil inventory, about 87% of the natural gas contract-backed inventoried energy elected into the forward component of the program.

Although demand response was permitted to participate in IEP, no demand response resources opted to participate in either year of the program. Electric storage elected 4 GWh forward, more than double Winter 2024, and delivered almost 5.6 GWh on average following inventoried energy days.

2.5.3 Program Impact

This section assesses IEP performance against its high-level goals. Specifically, it assesses:

- *oil inventories* to determine if IEP encouraged resources to arrange for more inventoried energy at the start of the winter and replenish inventoried energy if it was depleted during the winter;
- *energy market outcomes* to determine whether IEP changed if (or when) inventoried energy was converted to electric energy.[42]

Oil Inventories

Starting oil inventories in Winter 2025 were about 1,750 GWh, similar to the previous winter. The starting oil inventories in both years of the IEP program were higher than year preceding the IEP program (Winter 2023) despite less favorable forward market conditions.[43] Although it is difficult to draw a causal link to the IEP, it is noteworthy that the increase was entirely attributable to IEP-participant stations, which began Winter 2024 with 170 GWh more fuel than the previous winter.[44] By contrast, non-participant stations started Winter 2024 with 6 GW less fuel compared to the previous winter.[45] In contrast to Winter 2024, in which only 61 GWh of oil was consumed, Winter 2025 saw 726 GWh of oil generation, comparable to the 715 GWh of oil generation in Winter 2022.

In Winter 2025, only 56% of the oil consumed for generation was replenished (407 GWh). In Winter 2023, prior to IEP implementation, 112% of oil consumed for generation was replenished

[41] 4,900 MW per hour = 352 GWh inventoried energy times 1,000 MW/GW divided by 72 hours. Dual fuel capacity that could be directly linked to a gas contract are included in the 352 GWh of natural gas inventory.

[42] An assessment of potential capacity market outcomes can be found in the 2024 Winter Report: https://www.iso-ne.com/static-assets/documents/100011/2024-winter-quarterly-markets-report.pdf

[43] At the end of September 2022, forward on-peak New England Hub prices for Winter 2022-2023 were over $100/MWh higher than the estimated cost of oil generation, based on forward residual oil prices. By contrast, at the end of September 2024, forward on-peak New England Hub prices for Winter 2024-2025 did not support (i.e., were lower than) the estimated cost of oil generation. Oil generation was only “in-the-money”, based on future prices during January on-peak hours, by $10/MWh. (Data sourced from S&P Global Market Intelligence New York Harbor Residual Fuel Oil 1% Sulfur Futures and Monthly On-Peak Day-Ahead ISO-NE LMP futures as of the final day of September preceding the winter period).

[44] A “station” is a set of existing resources consisting of one or more assets located within a common property boundary.

[45] Approximately three quarters of the decline in starting inventories among non-participating stations is attributable to retirements or long-term outages rather than a decline in the average starting inventory at each station.

and ending inventories exceeded inventories at the beginning of the Winter. Relatively low Winter 2024 oil replenishment indicates that IEP did not lead to observed incremental replenishment.

Energy Market Outcomes

Although at least 75% of non-zero estimated energy market opportunity costs were driven by IEP, we estimate that IEP did not have any meaningful impact on short-term market outcomes.[46] As discussed in the Energy Market Opportunity Cost (EMOC) section, every uncommitted unit that priced in EMOCs was either offered on gas (so did not incur an EMOC) or was extramarginal with or without their EMOC.

2.5.4 Future Considerations

As currently envisioned, the Resource Capacity Accreditation (RCA) proposal should provide a more direct means to procure the reliability attributes currently delivered through the IEP, which may ultimately fulfill the goals of the IEP.[47] Specifically, the RCA proposes to accredit resources based on their reliability contributions to resource adequacy. For example, under RCA, an oil-fired resource's accreditation value will reflect its on-site fuel storage capability, while a gas-fired resource's accreditation value will reflect both gas infrastructure limitations and individual fuel arrangements. Resources will be compensated based on their reliability contributions and will reflect the incremental costs of making fuel arrangements to meet their capacity obligations in their capacity offers. In addition, a move to a prompt capacity market would enhance these market-based assessments by accrediting capacity closer to the commitment period when the resource is obligated to deliver its capacity.

[46] If a unit is participating in IEP and there is a forecasted IEP date on the horizon, an IEP-driven EMOC only requires inventory to fall below the unit's 72-hour maximum output. An EMOC that is not driven by IEP requires a unit to fully deplete their fuel inventory.

[47] For an overview of the RCA project see the *ISO's Resource Capacity Accreditation in the Forward Capacity Market Key Project* page, available at https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm.

Section 3
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes for Winter 2025 and preceding seasons. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 3-1 below.

Table 3-1: High-level Market Statistics

Market Statistics	Winter 2025	Fall 2024	Winter 2025 vs Fall 2024 (% Change)	Winter 2024	Winter 2025 vs Winter 2024 (% Change)
Real-Time Load (GWh)	32,068	26,240	22%	30,419	5%
Peak Real-Time Load (MW)	19,645	17,059	15%	18,438	7%
Average Day-Ahead Hub LMP ($/MWh)	$116.73	$35.91	225%	$48.66	140%
Average Real-Time Hub LMP ($/MWh)	$114.80	$35.72	221%	$44.39	159%
Average Natural Gas Price ($/MMBtu)	$13.58	$1.95	596%	$4.87	179%
Average No. 6 Oil Price ($/MMBtu)	$14.69	$13.91	6%	$14.94	-2%

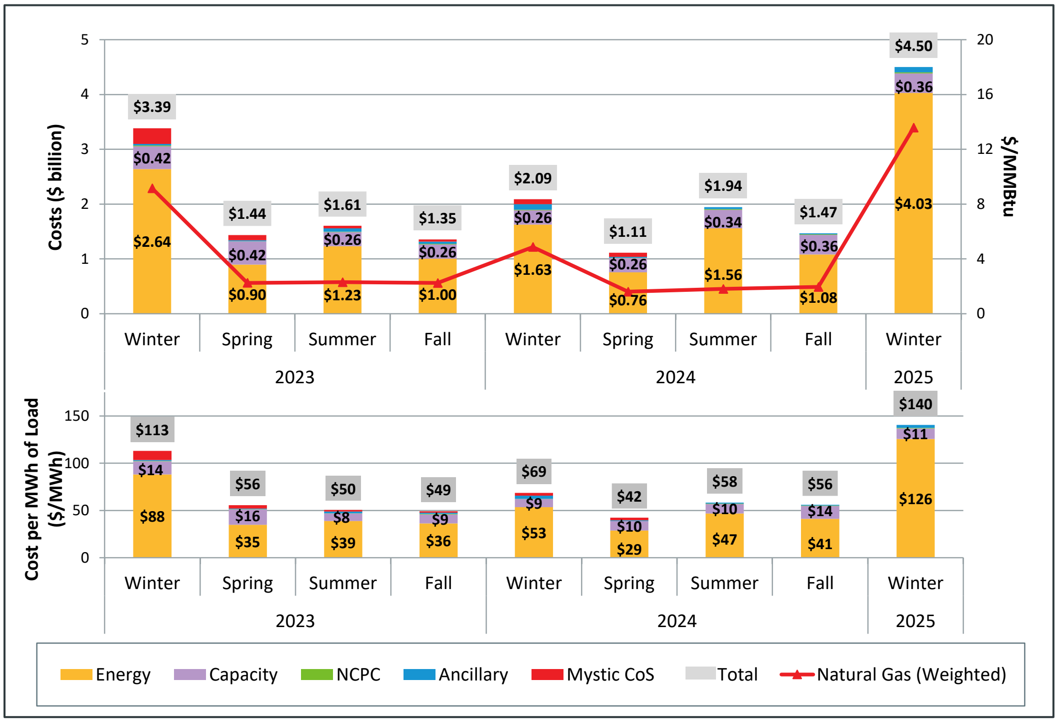
Key observations from the table above include:

- Average real-time load increased by 5% in Winter 2025 relative to Winter 2024, driven by colder weather throughout the season. Section 3.2 below discusses load in more detail.
- Average natural gas prices increased substantially in Winter 2025 compared to Winter 2024 (up 179%), reflecting colder weather and lower national storage levels. Section 2 above discusses the gas market in more detail.
- Higher natural gas prices were the primary driver of increased day-ahead and real-time LMPs. Winter 2025 saw average day-ahead LMPs of $116.73/MWh, 140% higher than in Winter 2024 ($48.66/MWh). The upward pressure of higher natural gas prices on LMPs was partially offset by oil generation displacing expensive gas generation on the coldest days.

3.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market and the average natural gas price (in $/MMBtu) are shown in Figure 3-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [48,49]

Figure 3-1: Wholesale Market Costs and Average Natural Gas Prices by Season

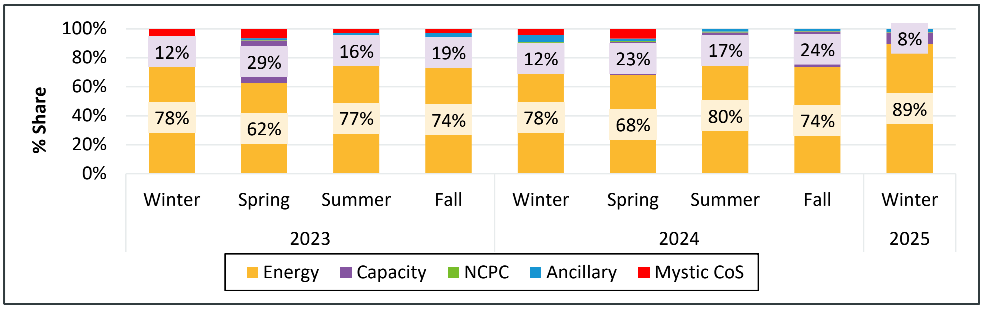


In Winter 2025, the total estimated wholesale cost of electricity was $4.50 billion (or $140/MWh), an increase of 116% compared to $2.09 billion in Winter 2024, and an increase of 207% over the previous quarter (Fall 2024) due to higher energy costs. Natural gas prices continued to be a key driver of energy prices. The share of each wholesale cost component is shown in Figure 3-2 below.

[48] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data.

[49] 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 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 11 on D+2.

Figure 3-2: Percentage Share of Wholesale Cost



Energy costs were $4.03 billion ($126/MWh) in Winter 2025, up 147% on Winter 2024 costs, driven by a substantial increase in natural gas prices (up 179%). Energy costs made up 89% of the total wholesale costs.

Capacity costs are determined by the clearing price in the primary forward capacity auction (FCA). In Winter 2025, the FCA 15 clearing price resulted in capacity payments of $359 million ($11/MWh), representing 8% of total costs. The current capacity commitment period (CCP15, June 2024 – May 2025) cleared at $2.61/kw-month for Rest-of-Pool. This was 30% higher than the primary auction clearing price of $2.00/kW-month for the prior capacity commitment period. Section 6 discusses recent trends in the Forward Capacity Market in more detail.

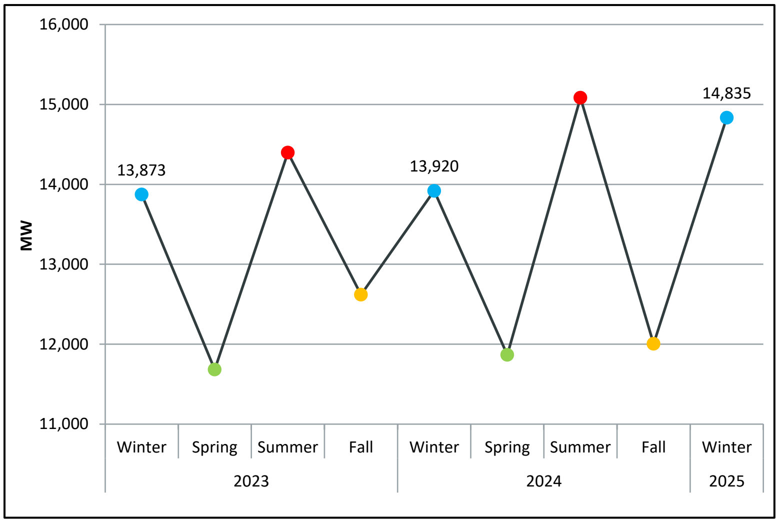
At $16.0 million ($0.50/MWh), Winter 2025 Net Commitment Period Compensation (NCPC) costs represented 0.4% of total energy costs, a similar share compared to other quarters in the reporting horizon. Section 4.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves, regulation, and Inventoried Energy Program (IEP) costs, totaled $100 million ($3.12/MWh) in Winter 2025, 2% of total costs. Ancillary service costs were similar to those of Winter 2024 ($103 million).

3.2 Load

New England winter loads are driven by heating demand. Average seasonal loads through Winter 2025 are shown in Figure 3-3 below.

Figure 3-3: Average Hourly Load

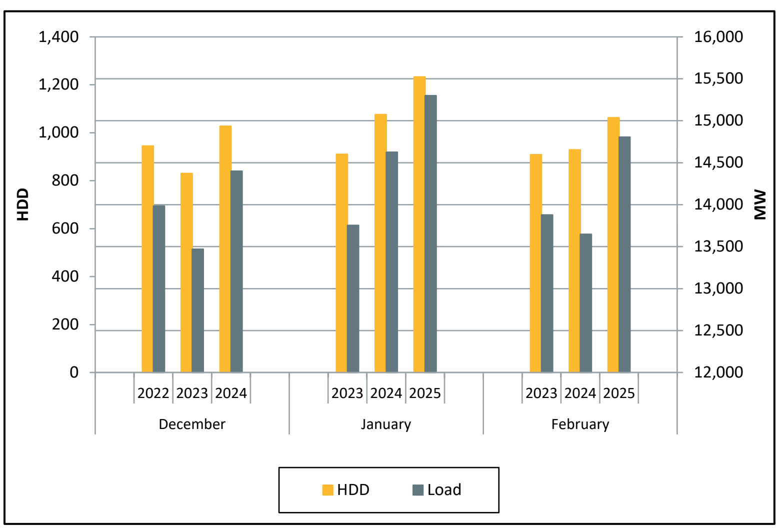


Load averaged 14,835 MW in Winter 2025, up 7% from Winter 2024. Winter 2025 was the coldest New England winter on average in ten years. Cold weather resulted in higher heating demand compared to the relatively mild winters of 2023 and 2024. While net loads increased in Winter 2025, behind-the-meter (BTM) solar load reductions increased to 290 MW on average, up from 260 MW in Winter 2024. Estimated BTM capacity reached 5,000 MW in early 2025.

Load and Temperature

The stacked graph in Figure 3-4 below compares average monthly load (right axis) to the monthly total number of heating degree days (left axis).

Figure 3-4: Monthly Average Load and Monthly Total Heating Degree Days

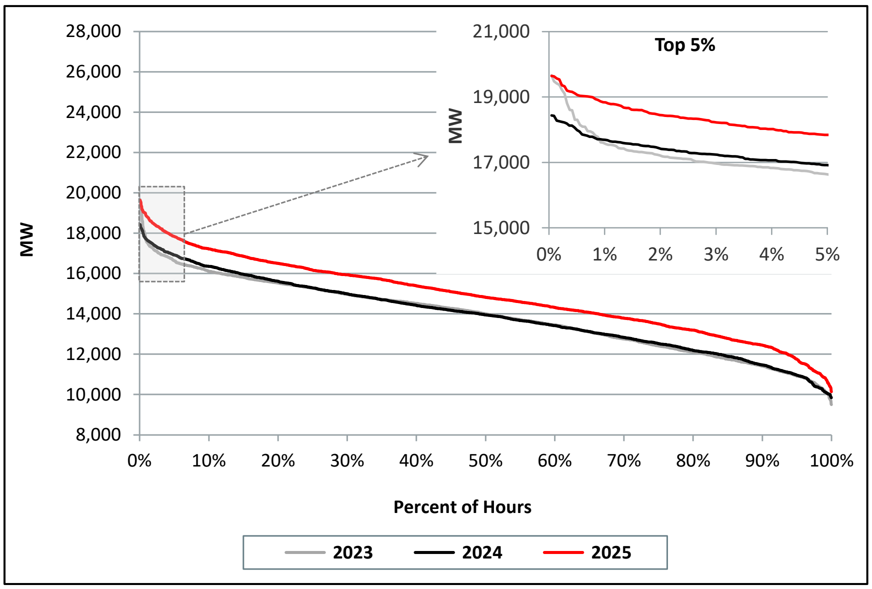


Weather in Winter 2025 was colder than Winters 2023 and 2024 across all months, and load increased by at least 5% each month relative to 2024. Notably, January 2025 was the coldest January in New England since 2022, and January loads averaged over 15,000 MW. Cold temperatures persisted through February, which had over 1,000 HDDs and average loads just below 15,000 MW.[50]

Peak Load and Load Duration Curves

New England's system load over the past three winter seasons is shown as load duration curves in Figure 3-5 below, with the inset graph showing the 5% of hours with the highest loads.

Figure 3-5: Load Duration Curve



Winter 2025 peak load reached 19,639 MW on January 22, when temperatures were 13°F during the evening peak. Cold temperatures drove peak loads during the season, and many of the peak load hours occurred during Inventoried Energy Program (IEP) days.[51]

Load Clearing in the Day-Ahead Market

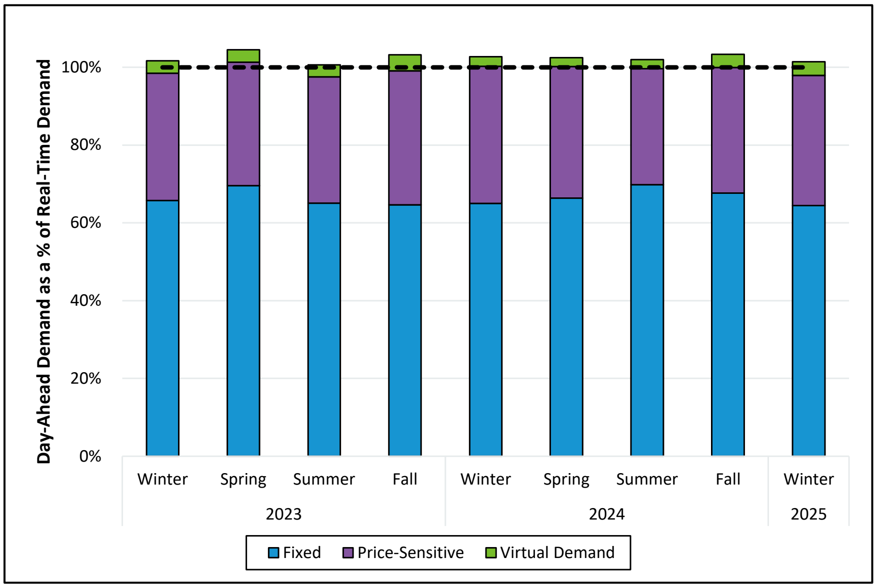
The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Analysis, it influences generator commitment decisions for the operating day.[52] The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 3-6 below.

[50] Heating degree days (HDD) measure how cold an average daily temperature is 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's average temperature is 60°F, the day has 5 HDDs.

[51] See 2.5 for a discussion of the Inventoried Energy Program.

[52] The Reserve Adequacy Analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. The objective is to minimize the cost of bringing additional capacity into the real-time market.

Figure 3-6: Day-Ahead Cleared Demand as a Percent of Real-Time Demand



Participants cleared 101% of load in the day-ahead market on average in Winter 2025, down from 103% in Winter 2024. Fixed demand bids accounted for 64% of cleared demand, while priced bids accounted for 33%. Participants continued to submit bid prices well above expected market prices, and the majority of priced bids were therefore functionally similar to fixed bids. Virtual demand accounted for 3% of cleared day-ahead bids. Virtual demand increased in Winter 2025 as discussed in Section 4.3.

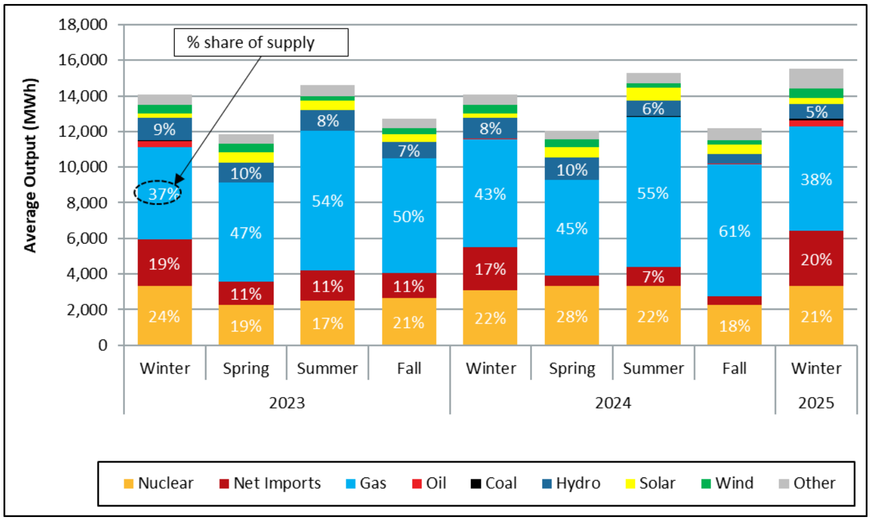
3.3 Supply

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

3.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The shares of energy production by generator fuel type for Winter 2023 through Winter 2025 are illustrated in Figure 3-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of average generation from that fuel type.[53]

Figure 3-7: Share of Electricity Generation by Fuel Type



Average output in Winter 2025 (15,550 MWh) was significantly higher than prior winters. This increase was driven by higher average loads, as discussed in Section 3.2. In keeping with prior winter seasons, the three largest contributors to New England's energy supply were natural gas generators, nuclear generators, and imports from neighboring control areas. Collectively, these three forms of supply provided 79% of the region's energy, on average. Notably, the share of energy supply from net imports increased significantly from the low levels observed in the spring, summer, and fall seasons of 2024. See Section 3.3.2 for further details.

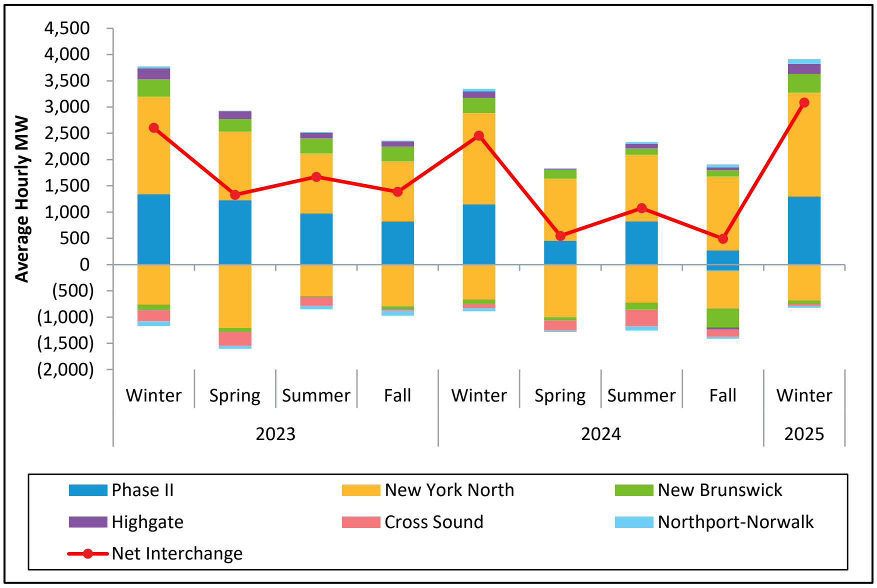
Oil-fired generation supplied 2.2% of energy in Winter 2025, the largest share for this fuel type during the study period. This increase in production from oil-fired generation resulted from colder temperatures periodically driving natural gas prices above oil prices, causing oil-fired generators to be in-merit.

[53] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response.

3.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Winter 2025.[54] The average hourly import (positive), export (negative) and net interchange power volumes by external interface for the last nine seasons are shown in Figure 3-8 below.

Figure 3-8: Average Hourly Real-Time Imports, Exports and Net Interchange



On average, the net flow of energy into New England was 3,088 MW per hour in Winter 2025, the highest level of net imports over the prior nine quarters. Despite declining levels of imports in recent years, the colder winter temperatures lead to increased natural gas demand in the region as heating demand for the fuel rises. This results in upward pressure on natural gas prices and LMPs, which incentivizes higher volumes of imports from neighboring regions. Total net interchange in Winter 2025 represented 21% of load (NEL), which was slightly higher than in Winter 2024 (18%).

Canadian Interfaces

In Winter 2025, net imports from the Canadian interfaces averaged 1,783 MW per hour, which was a 21% increase compared to Winter 2024. In Quebec, abundant water resources and hydro generation provide excess electricity supply, which can be sold into New England. While dry conditions in Canada have recently limited imports to New England, high natural gas prices and LMPs during the winter provide strong price signals for imports.

[54] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound cable, and the Northport-Norwalk cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces, which both connect with the Hydro-Québec control area, and the New Brunswick interface.

At the Phase II interface, most day-ahead import transactions are bid as priced transactions and will only clear if they are priced below the LMP.[55] With higher day-ahead LMPs this winter (140% increase), net imports at the Phase II interface increased by 13%, averaging nearly 1,300 MW per hour.[56] Both the Highgate and New Brunswick interfaces also saw increases in net imports. At the New Brunswick interface, net imports increased by 44% year-over-year, averaging 300 MW per hour. Net imports at Highgate averaged 187 MW per hour, a 51% increase from the previous winter.

New York Interfaces

Despite similar pricing outcomes between the two regions, New England imported more energy from New York in Winter 2025 than the prior winter. On average, New England imported of 1,305 MW per hour across the three New York interfaces, a 33% increase compared to the prior winter. At the New York North interface, net imports averaged 1,295 MW per hour, the highest volume over the prior nine quarters. Despite New York prices increasing by more than New England prices, participants offered more day-ahead, fixed external transactions. These fixed bids will clear regardless of the prices at the interface. While these bids appear uneconomic at times, external transactions can receive out-of-market revenues not captured in wholesale electricity pricing (e.g., Renewable Energy Certificates or Power Purchase Agreements).

New England typically exports energy to Long Island, but higher gas prices and LMPs this winter led to New England importing 10 MW per hour from Long Island. At the Northport-Norwalk interface, net imports averaged 54 MW per hour this winter, after exporting 10 MW per hour the prior winter. At the Cross Sound Cable interface, New England was still an exporter of energy, but net exports fell to 45 MW per hour, which was a 48% decrease compared to Winter 2024. At both of these interfaces, average day-ahead LMPs were higher in New England compared to New York this winter. In Winter 2024, day-ahead LMPs were higher on the New York side of the interface. The price changes led to more energy flowing into New England this winter.

[55] Cleared import transactions tend to be priced in the day-ahead market but not re-offered in the real-time market and therefore are scheduled like fixed transactions in the rea-time market. Therefore, real-time imports tend to be more correlated with day-ahead prices than real-time prices.

[56] For more information on Québec reduction in exports, see Hydro-Québec's *Quarterly Bulletin, Third Quarter 2023*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2023-3.pdf

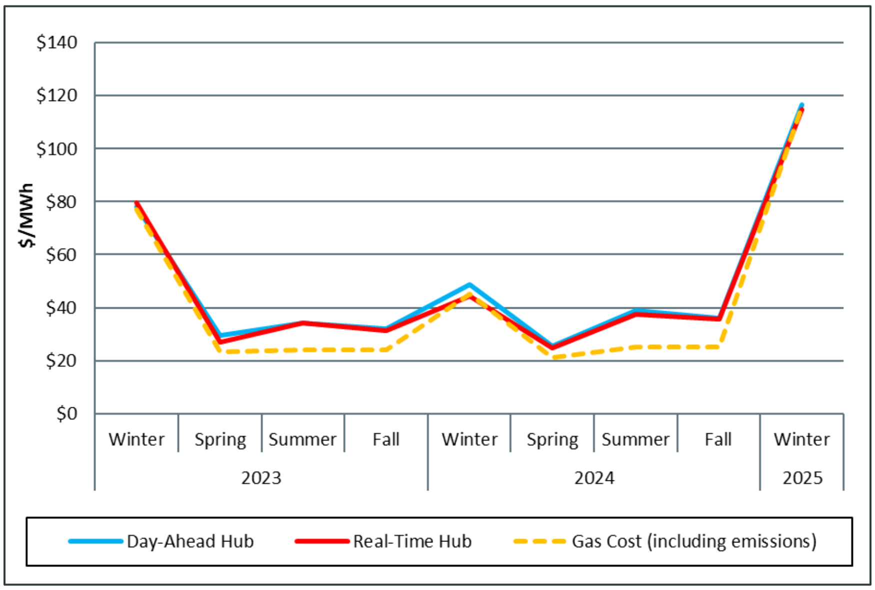
Section 4
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

4.1 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 4-1, 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.[57]

Figure 4-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 4-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand.

Day-ahead and real-time Hub prices averaged $116.73/MWh and $114.80/MWh respectively in Winter 2025, up by $68-$70/MWh from Winter 2024. The increase was due to higher natural gas costs, which averaged $115.91/MWh in Winter 2025, and also increased by around $70/MWh compared to the previous winter. Natural gas costs increased due to colder weather, higher loads, and lower national storage levels.

[57] The natural gas cost is based on the seasonal average natural gas price 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.

In other recent quarters, we found that rising Regional Greenhouse Gas Initiative (RGGI)[58] costs contributed significantly to the cost of generating on natural gas. However, in Winter 2025, the cost of fuel increased more significantly than RGGI costs. From Winter 2024 to Winter 2025, RGGI prices rose from $18.34 to $21.47/short ton of CO_2. This increased the RGGI adder for natural gas generator costs from $8.37 to $9.80/MWh. This increase may be explained by expectations of future market changes.[59] The large increase in gas prices more than offset the higher RGGI prices, resulting in a lower contribution to generation costs of about 7% in Winter 2025 compared to about 13% in Winter 2024 or about 40% in Fall 2024.

Prices did not differ significantly among the load zones in either market in Winter 2025, indicating that there was relatively little transmission congestion on the system at the zonal level.

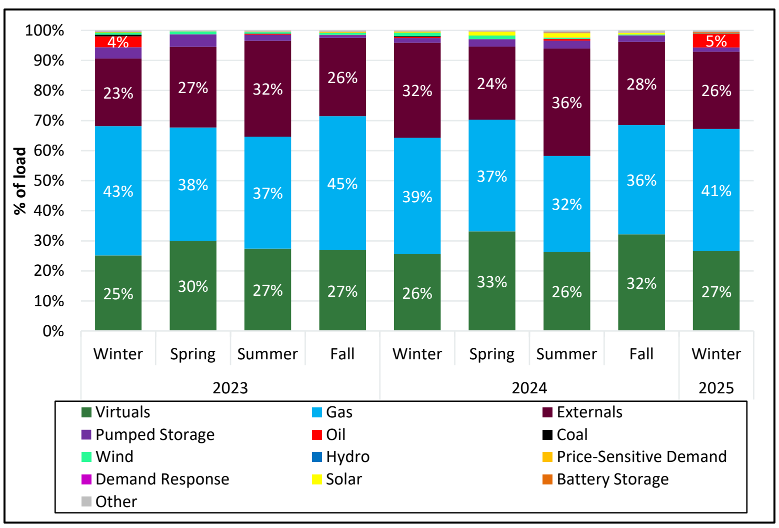
4.2 Marginal Resources and Transactions

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 the marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Day-ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2023 is illustrated in Figure 4-2 below.[60]

Figure 4-2: Day-Ahead Marginal Units by Transaction and Fuel Type



[58] RGGI is a marketplace for CO_2 credits that covers all six New England states as well as other states in the Northeast and Mid-Atlantic regions. It operates as a cap-and trade system, where fossil fuel generators must purchase emission allowances equal to their level of CO_2 emissions over a specific compliance period. See RGGI's Elements of RGGI page, available at https://www.rggi.org/program-overview-and-design/elements

[59] Additional information available at https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2024_Q4.pdf

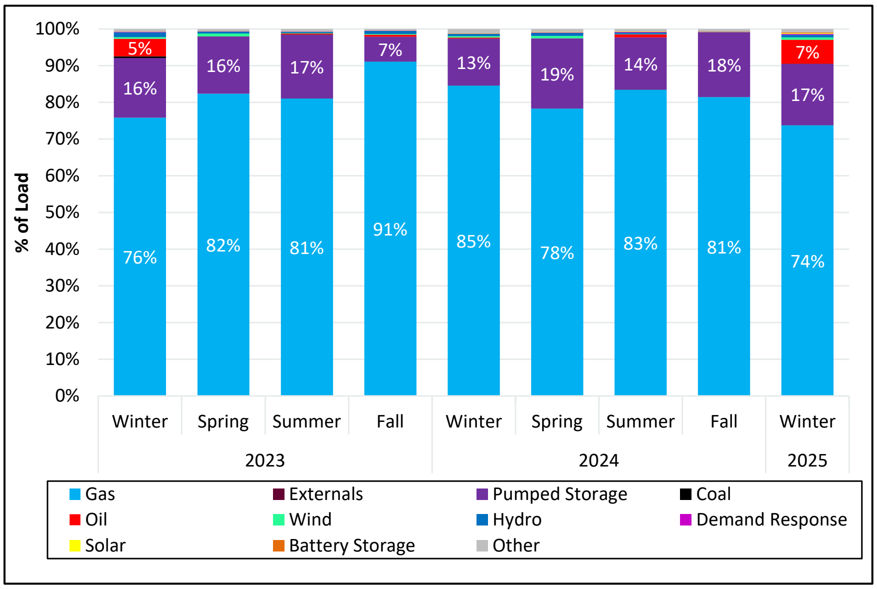
[60] The "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, and refuse.

Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 41% of total day-ahead load in Winter 2025. Virtual transactions and external transactions were next, setting price for 27% and 26% of load, respectively. Oil-fired generation set price for 5% of load in the day-ahead market in Winter 2025, up from zero percent in Winter 2024. Oil tends to be in-merit for energy more frequently during the winter when cold weather can increase natural gas demand for heating, leading to higher prices for gas. One notable period of high oil generation marginality occurred between January 20-22 when temperatures fell as low as -2 °F in the region.

Real-time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2023 is shown in Figure 4-3 below.

Figure 4-3: Real-Time Marginal Units by Fuel Type



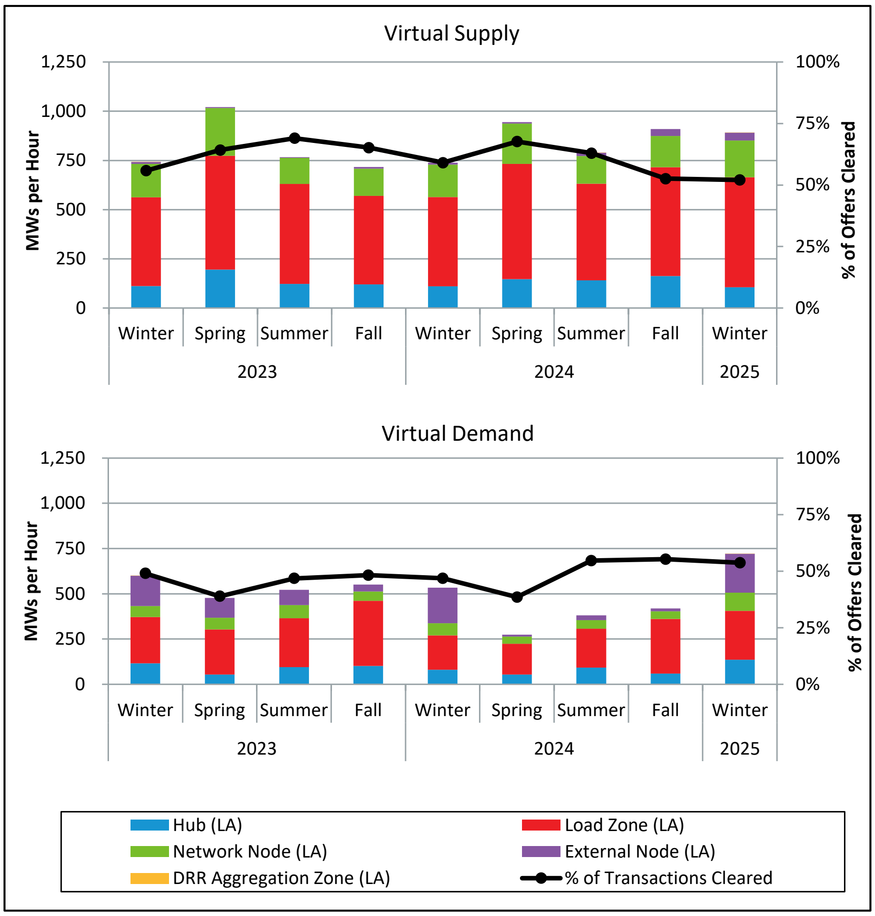
Natural gas-fired generators set price for the highest percentage of load in the real-time market in Winter 2025 (74%). Pumped-storage facilities (generation and demand) set price for 17% of load in Winter 2025, a level that was in-line with others over the reporting period. Oil-fired generation set price for a share of load in the real-time market (7%) that was comparable to its value from the day-ahead market. All other resource types accounted for less than 3% of real-time load.

4.3 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 better reflect real-time conditions.

The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 4-4 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 (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 4-4: Cleared Virtual Transactions by Location Type



As seen in the top figure, virtual supply volumes continue to increase. This is due to:

1) the growing amount of solar settlement-only generation (SOG) and
2) the day-ahead bidding behavior of wind and solar generation.

Cleared virtual supply averaged 892 MW per hour in Winter 2025, up 21% from Winter 2024 (738 MW per hour). By the end of Winter 2025, the installed capacity of solar SOGs was nearly 2,300

MW. Since SOGs cannot participate in the day-ahead market, participants often clear virtual supply on days when solar generation is expected to be high and impactful on real-time prices.

Participants also frequently use virtual supply to try to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind and solar generation. Beginning in December 2023, the Do-Not-Exceed (DNE) Dispatch Project expanded to include utility-scale (at least 5 MW installed capacity) solar generation. Typically, these wind and solar generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[61]

Cleared virtual demand averaged 721 MW per hour, the highest volume of cleared virtual demand over prior nine quarters. Throughout the last three winters, higher volumes of virtual supply have cleared at the Highgate interface, which interconnects New England to Québec. Importers at Highgate frequently offer high-priced virtual demand in conjunction with a low- or fixed-priced import transaction. The virtual demand transaction provides the importer with both a financial hedge and can help them clear the full volume of their import.

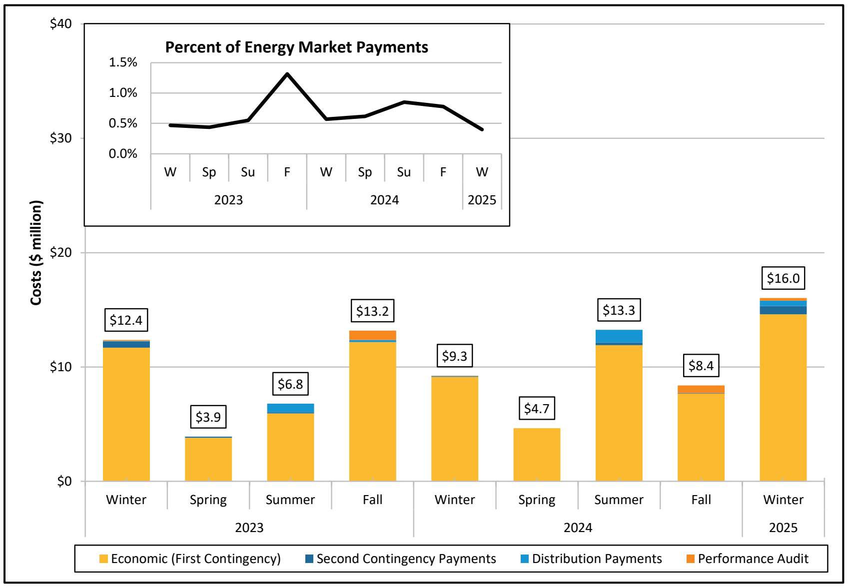
4.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) credits are make-whole payments to generators, external transactions, or virtual participants that incur uncompensated costs when following ISO dispatch instructions. NCPC categories include first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[62] Figure 4-5 below shows total NCPC by category and season for 2022-2025. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

[61] In Winter 2025 wind generation averaged 253 MW per hour in the day-ahead market, while real-time wind generation averaged 539 MW hour.

[62] 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).

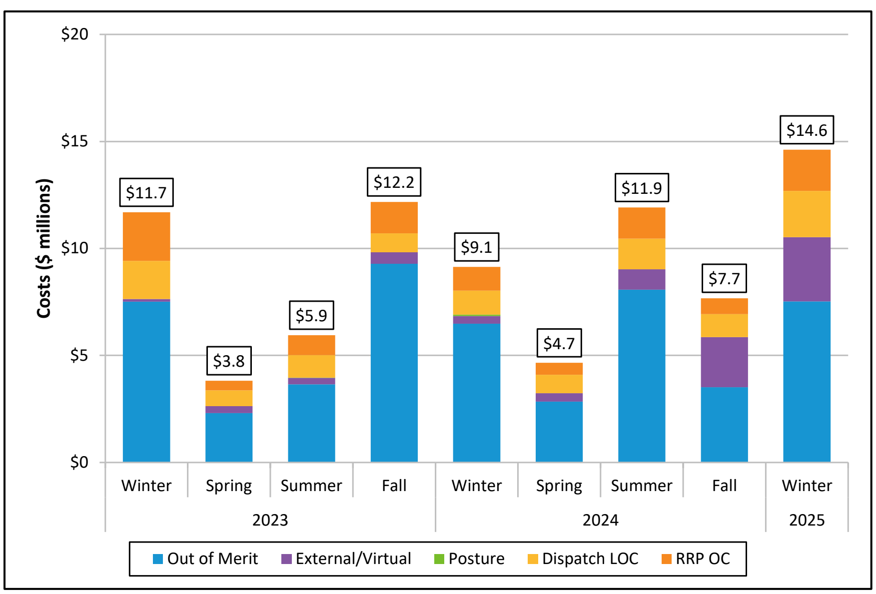
Figure 4-5: NCPC Payments by Category ($ millions)



NCPC payments totaled $16.0 million in Winter 2025, comprising 0.4% of energy market payments. While NCPC payments increased from Winter 2024, NCPC fell as a share of energy market payments as payments increased due to high LMPs throughout the season. First contingency payments totaled $14.6 million, or 91% of total NCPC payments. Local second contingency payments ($0.7 million) were primarily driven by commitments in the day-ahead market in the New Hampshire and Maine load zones. Local distribution payments totaled $0.5 million. Audit payments comprised the remaining $0.2 million of Winter 2024 NCPC.

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that incur opportunity costs by operating at an ISO-instructed dispatch point below their economic dispatch point (EDP). Figure 4-6 below shows economic payments by sub-category.

Figure 4-6: Seasonal Economic Uplift by Sub-Category



Out of merit payments totaled $7.5 million in Winter 2025, driven by both day-ahead and real-time fast-start commitment costs. Combined opportunity cost payments comprised 28% ($4.1 million) of total economic uplift. External and virtual payments totaled $3.0 million, continuing a trend of increased payments since Fall 2024. This trend is driven by congestion at external interfaces, and the resulting uplift payments are not allocated to load but are settled between importing and exporting market participants.[63]

4.5 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.[64] 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 winter seasons is provided in Table 4-1 below.[65]

Table 4-1: Hours and Level of Non-Zero Reserve Pricing

Product	Winter 2025		Winter 2024		Winter 2023	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$18.34	222.9	$18.14	140.0	$31.13	169.1
TMNSR	$40.79	2.6	$72.43	11.1	$682.89	4.3
TMOR	$20.22	1.3	$78.29	5.8	$490.95	3.7

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 223 hours during Winter 2025. This winter season had a higher frequency of TMSR prices than the prior two seasons, reflecting somewhat tighter real-time system conditions than prior winters on average, resulting in the need to more frequently re-dispatch resources in order to create TMSR. These re-dispatches occurred primarily during the morning and evening ramps. The average TMSR price, $18.34/MWh, was consistent with the prior winter season.

[63] For an example and explanation of congestion-driven day-ahead external NCPC, see the ISO-NE FAQ page for NCPC, available at https://www.iso-ne.com/participate/support/faq/ncpc-rmr.

[64] 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.

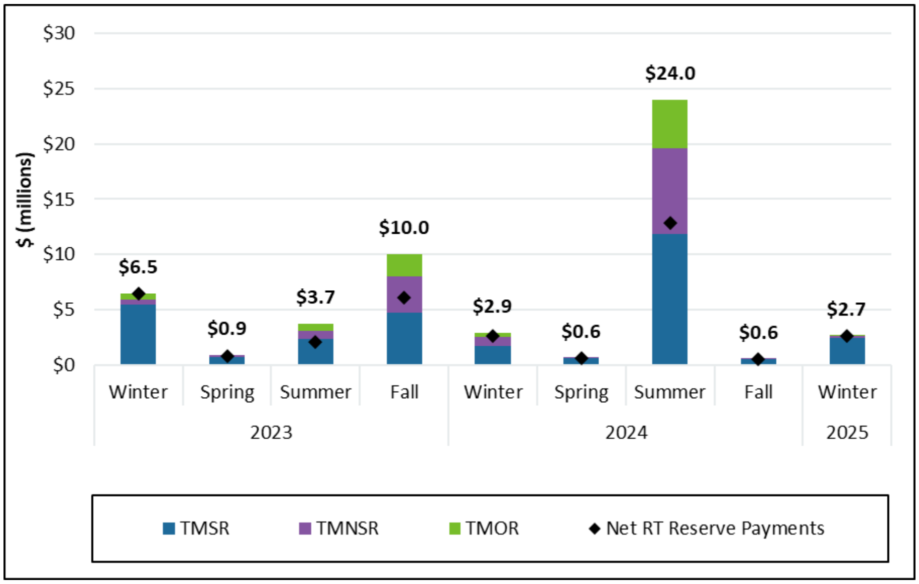
[65] The zonal thirty-minute reserve requirements did not bind in any of these winter seasons. As a result, real-time reserve prices in reserve zones were equal to those at the system level.

Non-zero TMNSR and TMOR prices occurred less frequently, and average prices were lower, in Winter 2025 than in prior winter seasons.[66] This pricing outcome reflects the fact that an ample supply of total ten and thirty minute reserve capability was generally available on the system in Winter 2025.

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 4-7 below.[67] The height of the bars indicates gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Market (FRM) resources providing real-time reserves).[68]

Figure 4-7: Real-Time Reserve Payments by Product



Net reserve payments in Winter 2025 ($2.6 million) were consistent with Winter 2024, and much lower than in Winter 2023, which included capacity scarcity conditions and associated high reserve prices. These payments were reduced only slightly from their gross level of $2.7 million as a result of Forward Reserve obligation charges.

Other notable seasonal reserve payments illustrated in this figure include Fall 2023, when planned outages of pumped-storage generators resulted in tighter reserve conditions and an increase in the frequency and magnitude of non-zero reserve pricing, as well as Summer 2024, which had long durations of capacity scarcity conditions.

[66] This is particularly true relative to Winter 2023, when capacity scarcity conditions occurred and produced very high average TMNSR and TMOR prices.

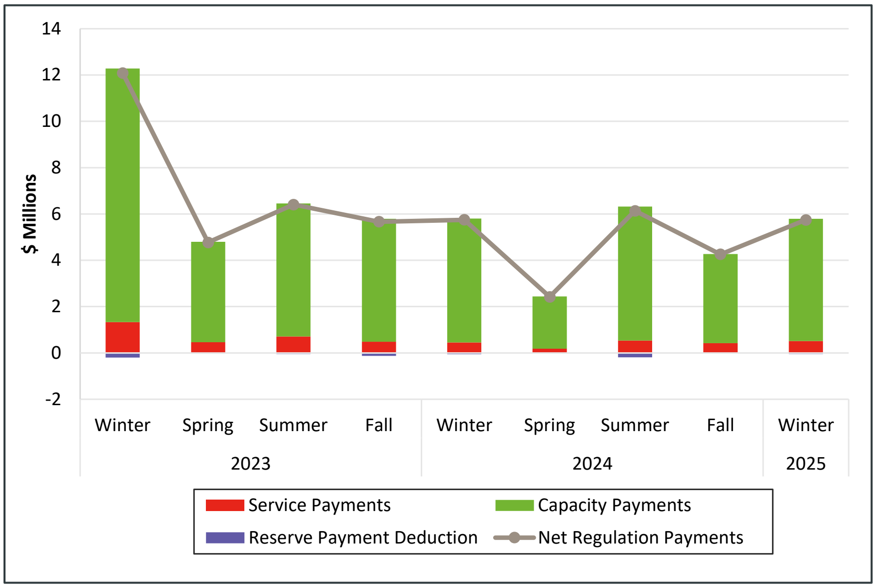
[67] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

[68] The FRM is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. For more information about forward reserve obligation charges, see *Section III Market Rule 1: Standard Market Design*, Section III.10.4, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

4.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. 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 are shown in Figure 4-8 below.

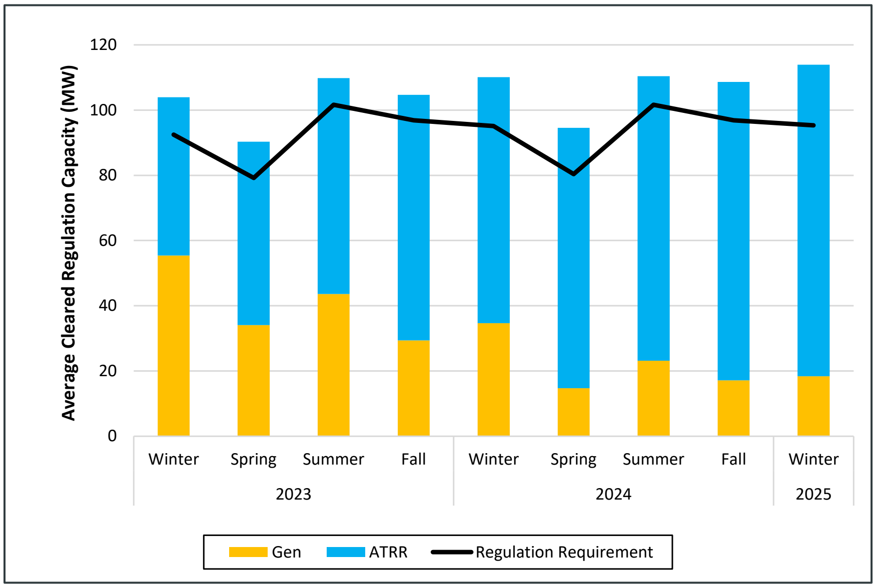
Figure 4-8: Regulation Payments



Total regulation market payments were $5.7 million during Winter 2025, up 35% from Fall 2024 payments but nearly identical to Winter 2024 payments. Though higher LMPs in Winter 2025 put upward pressure on regulation capacity prices, capacity offer prices were lower than in the previous winter, as lower cost alternative technology regulation resources continue to add to the regulation mix, increasing their relative share.

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 4-9 below.

Figure 4-9: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed significantly over the reporting period. In Winter 2023, ATRRs (blue shading) cleared an average of 49 MW of regulation capacity, making up 47% of total cleared regulation. In Winter 2025, ATRRs provided 96 MW or 84% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 246 MW on average in Winter 2025, up from 144 MW in Winter 2023. The change in resource mix also highlights the fact that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

Section 5
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. In section 5.1, we evaluate energy market competitiveness by quarter using two structural market power metrics at the system level. In section 5.2, we provide statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM reference level.

5.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in real time using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[69]

When a participant's available supply exceeds the supply margin[70], they are considered pivotal.[71] We calculate the percentage of five-minute pricing intervals with at least one pivotal supplier by quarter. The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 5-1 below.

Table 5-1: 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%

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. The Fall 2023 RSI was

[69] 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.

[70] 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* - [$Reserve\ Requirement$]

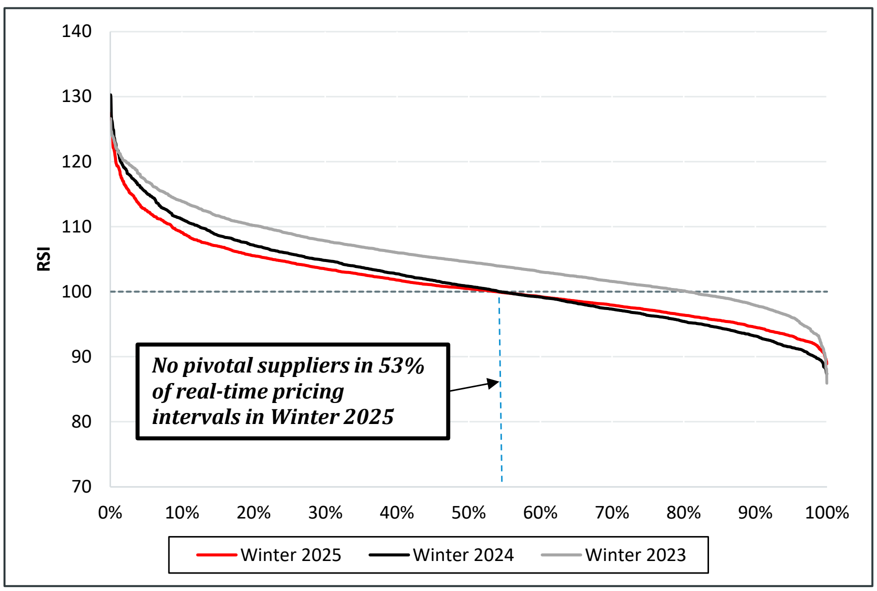
[71] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

below 100 due to lower reserve margins that resulted from several long-term pumped-storage generator outages. Pumped-storage units typically provide large volumes of reserves, as they can come online at their full capacity quickly.

There was at least one pivotal supplier in 47% of real-time pricing intervals in Winter 2025, a similar value to Winter 2024 (45%), but lower than that of Winter 2023 (20%). The two most recent winters saw lower average reserve margins compared to Winter 2023. The lower margins in Winter 2025 were due to higher loads and a higher reserve requirement (resulting from a higher first contingency value), while the lower margins in Winter 2024 resulted from the long-term pumped-storage generator outages that continued from Fall 2024. When reserve margins are lower, it is more likely that the largest supplier is needed to meet load and the reserve requirement.

Duration curves that rank the average hourly RSI over each winter quarter in descending order are illustrated in Figure 5-1 below. The figure shows the percent 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 5-1: System-Wide Residual Supply Index Duration Curves



In Winter 2025, the RSI was similar to that of Winter 2024, but lower than in Winter 2023 across most ranked observations. Both Winter 2024 and 2025 saw lower average reserve margins compared to Winter 2023, as discussed above.

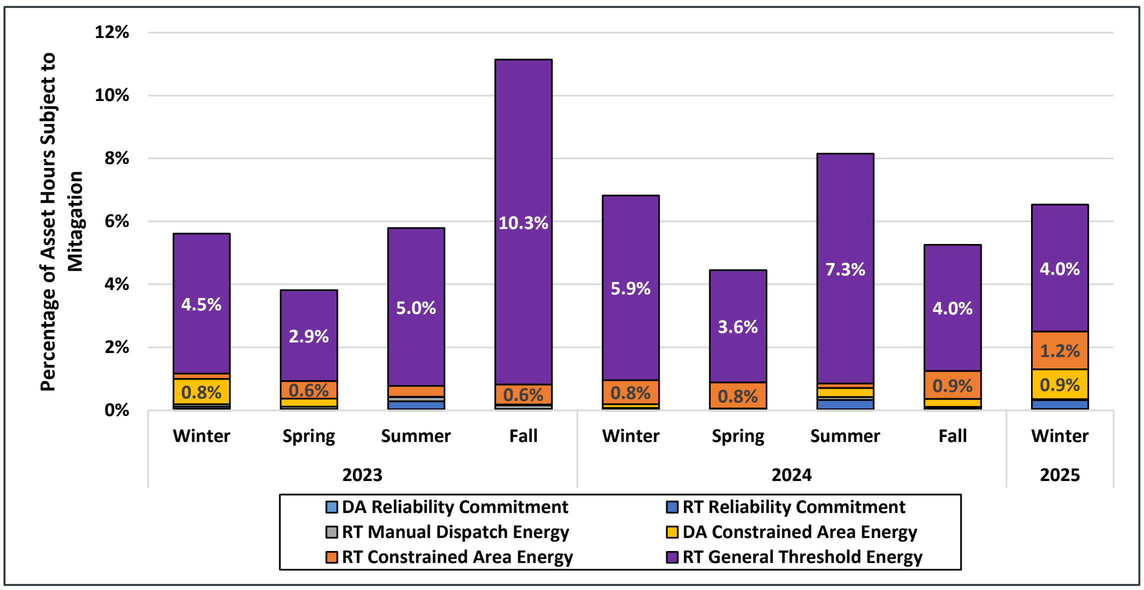
5.2 Energy Market Supply Offer Mitigation

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 Winter 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 Winter 2025 is shown below in Figure 5-2.[72]

Figure 5-2: Energy Market Mitigation Structural Test Failures



In Winter 2025, approximately 447,000 asset hours were subject to mitigation, of which 18,000 (6.5%) failed structural tests.[73] The structural test for general threshold energy mitigation fails the most often and is triggered anytime a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 5-3 along with the total amount of asset hours subject to mitigation (white boxes).

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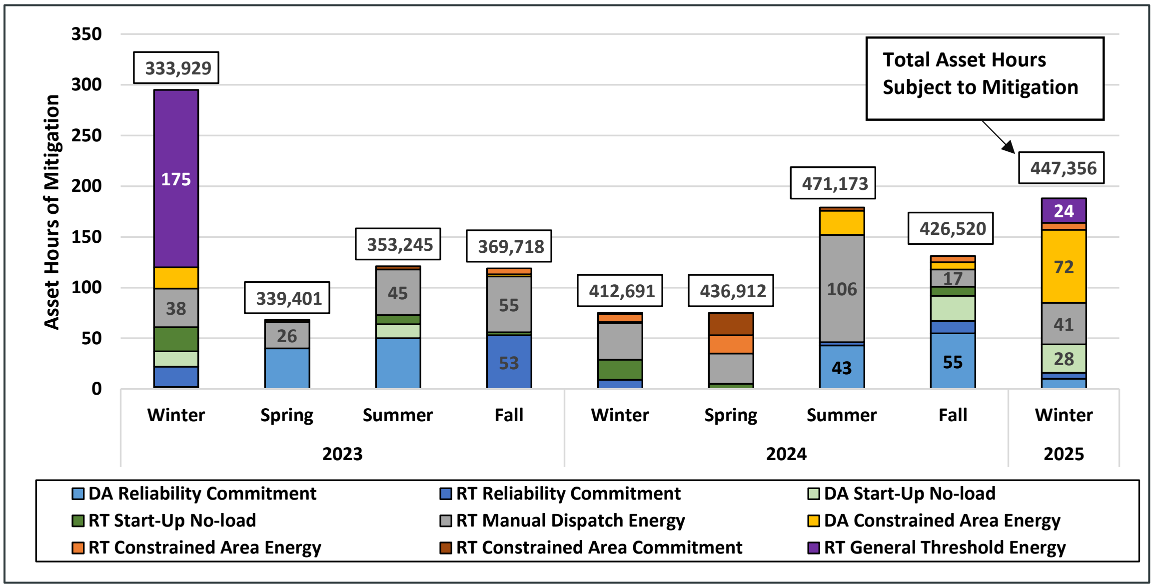
[72] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available 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.

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

Figure 5-3: Energy Market Mitigation Asset Hours



Total mitigation asset hours increased from 75 hours in Winter 2024 to 188 hours in Winter 2025.[74]

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. Day-ahead constrained area energy mitigation was the most frequent mitigation type in Winter 2025, totaling 72 asset hours. Most of these mitigations occurred between December 2 and December 4, when planned transmission line and equipment outages caused a binding constraint on the North-East New England Import Interface.

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.[75] In Winter 2025, reliability commitments mitigations totaled 16 asset hours. The mitigated generators were committed for either local second contingency protection or performance audits.

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.[76] SUNL mitigations occur very infrequently and may reflect a participant's failure to update

[74] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets (2025 Update)* (May 23, 2025), Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf.

[75] 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.

[76] 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).

energy market supply offers as fuel prices fluctuate – particularly natural gas. In Winter 2025, only one participant was associated with the 28 asset hours of SUNL commitment mitigation.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation typically occurs infrequently. There were 24 asset hours of general threshold energy mitigation in Winter 2025, and all occurred on one day for a single supplier. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with three participants accounting for 81% of the structural test failures in Winter 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 157 asset hours of manual dispatch in Winter 2025. Due to a relatively tight conduct test, manual dispatch energy mitigation generally occurs more often than most other mitigation types, reaching a total of 41 asset hours in Winter 2025.

Section 6
Forward Markets

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

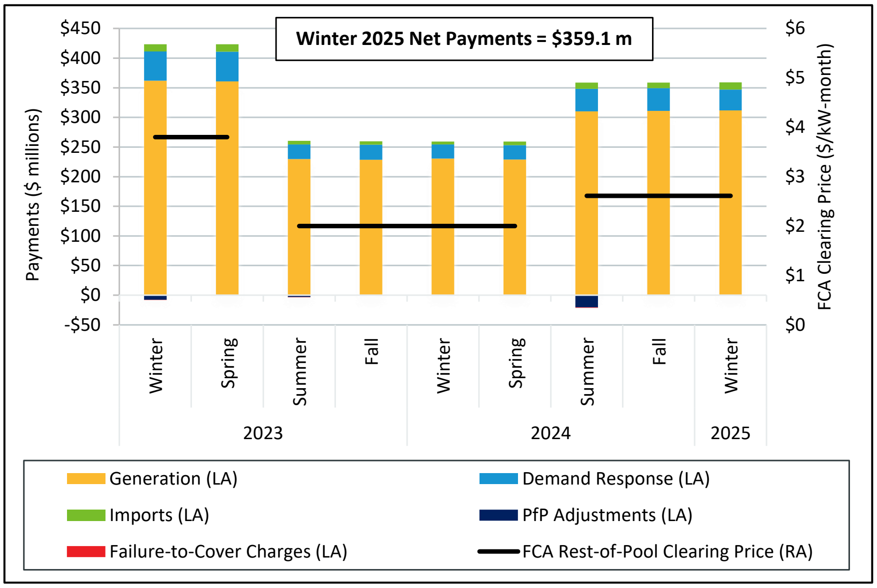
6.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Winter 2025 started on June 1, 2024, and will end on May 31, 2025. The corresponding Forward Capacity Auction (FCA 15) cleared at $2.61/kW-month, 30% higher than FCA 14. The auction cleared with 34,621 MW of Capacity Supply Obligation (CSO), surpassing the net installed capacity requirement (Net ICR) of 33,270 MW. Price separation between zones occurred in FCA 15, with a lower price ($2.48/kW-month) in the export-constrained Northern New England (NNE) and nested Maine capacity zones and a higher price ($3.98/kW-month) in the import-constrained Southeast New England (SENE) capacity zone. Battery storage resources comprised the largest share of new cleared generating capacity. The cost-of-service agreement that retained Mystic 8 and 9 during FCA 13-FCA 14 ended and the generators retired effective June 1, 2024. The results of FCA 15 led to a projected total annual cost of $1.32 billion in capacity payments, 39% higher than capacity payments incurred in FCA 14.[77]

Total FCM payments, as well as the clearing prices for Winter 2023 through Winter 2025, are shown in Figure 6-1 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, 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 light blue bar represents Failure-to-Cover charges.

[77] For more information on FCA 15, see our Winter 2021 Quarterly Markets Report (April 28, 2021), available at https://www.iso-ne.com/static-assets/documents/2021/04/2021-winter-quarterly-markets-report.pdf.

Figure 6-1: Capacity Market Payments



Capacity payments totaled $359.1 million in Winter 2025. The increase from Winter 2024 was caused by the higher capacity clearing prices in FCA 25. There were no PfP events or related adjustments during the season, and Failure-to-Cover charges were minimal.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Winter 2025 alongside the results of the relevant primary FCA are detailed in Table 6-1 below.

Table 6-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

				Capacity Zone/Interface Prices ($/kW-mo)				
FCA # (Commitment Period)	Auction Type	Period	Cleared MW*	Rest-of-Pool**	Maine	Northern New England	Southeastern New England	New York AC Ties
FCA 15 (2024-2025)	Primary	12-month	34,621	2.61	2.48	2.48	3.98	
	Monthly Reconfiguration	Feb-25	1,024	3.80				
	Monthly Bilateral	Feb-25	59	2.06				
	Monthly Reconfiguration	Mar-25	1,294	1.68			2.24	1.35
	Monthly Bilateral	Mar-25	59	1.77				
	Monthly Reconfiguration	Apr-25	1,474	2.50				1.35
	Monthly Bilateral	Apr-25	14	0.25				

**represents cleared supply/demand*

***bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions (MRAs) took place in Winter 2025: the February 2025 auction in December, the March 2025 auction in January, and the April 2025 auction in February. The reconfiguration auctions showed relatively high participation with over 1,000 cleared MW in each auction, and price variation from $3.80/kw-month in February to $1.68/kw-month in March. Some price separation occurred with higher prices in the import-constrained Southeastern New England capacity zone in March, and lower prices at the New York AC ties for both March and April.

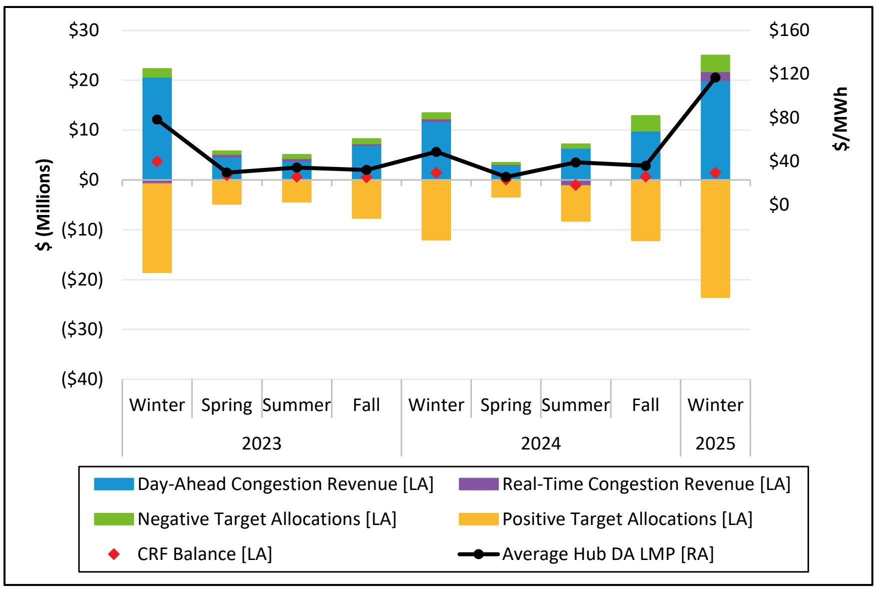
6.2 Financial Transmission Rights

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, and
3) the revenue associated with transmission congestion in the real-time market.

Figure 6-2 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.[78,79] This figure also depicts the quarterly average day-ahead Hub LMP.[80]

Figure 6-2: Congestion Revenue and Target Allocations by Quarter



Most congestion-related totals moved in line with the day-ahead energy price, which rose from $48.66/MWh in Winter 2024 to $116.73/MWh in Winter 2025 (a 140% increase). Day-ahead congestion revenue amounted to $19.9 million in Winter 2025. This represented a 70% increase relative Winter 2024 ($11.8 million). Positive target allocations in Winter 2025 ($23.5 million) followed a similar trend, increasing by 96% relative to Winter 2024 ($12.0 million). One transmission constraint associated with the increased positive target allocations in Winter 2025 relative to Winter 2024 was the New York – New England (NYNE) interface. This interface bound in

[78] 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).

[79] Figure 6-2 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.

[80] 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").

20% of hours in the day-ahead market in Winter 2025 despite it being at full capability (1,600 MW) nearly the entire quarter. Flows over this interface often reach their limit when there are large price differences between the regions, such as those that can occur in the winter when the gas pipeline system into New England becomes more constrained. Negative target allocations in Winter 2025 ($3.2 million) increased by 175% from their Winter 2024 level ($1.1 million). Meanwhile, real-time congestion revenue in Winter 2025 ($1.9 million) remained generally in line with recent historical levels.

FTRs were fully funded in December 2024, January 2025, and February 2025.[81,82] At the end of 2024, the congestion revenue fund had a surplus of $3.1 million. Surpluses like this carry over until the end of the year and are then used to cover any unpaid monthly positive target allocations. In 2024, $1.8 million went to positive target allocations that had been underfunded during the year.[83] The remaining $1.3 million was then allocated to entities that had paid congestion costs during the year. At the end of February 2025, the congestion revenue fund had a surplus of $1.2 million.

[81] FTRs are said to be "fully funded" when sufficient revenue is collected from the energy market and from FTR holders with negative target allocations to pay FTR holders with positive target allocations all the revenue to which they are entitled.

[82] For more information about the monthly FTR settlement, see the *2024 and 2025 FTR Monthly Summaries*, available at https://www.iso-ne.com/static-assets/documents/100008/2024-monthly-summary.pdf and https://www.iso-ne.com/static-assets/documents/100020/2025_monthly_summary.pdf.

[83] FTRs were not fully funded in May, June, July, August, or September.

Appendix: Overview of FPA Process

Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that it differs significantly from the corresponding fuel index. As outlined in Section III.A.3.4(ii) of the Tariff, the submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its supply offer. When a participant submits an FPA, the IMM calculates the reference level for that resource using the cost-based methodology, which uses documented cost information provided by the participant to estimate incremental energy offers.[84] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[85]

$$\begin{aligned} \text{Incremental Energy} &= (\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} \\ &* \text{emissions allowance price}) + \text{variable operating and maintenance costs} \\ &+ \text{opportunity costs} \end{aligned}$$

Without an FPA, the IMM estimates the fuel costs in the preceding equation using automated index-based cost data received from third party vendors. Because the indices are based on historical transactions (in the case of natural gas, the weighted average price of the preceding day's next-day trading strip), they may not reflect current market prices. If the reference level is set too low, a resource runs the risk of inappropriate mitigation and failure to recover its operating costs. By overriding the fuel costs in the previous equation, FPAs provide a way to update fuel costs and reference levels in real time.

While FPAs can be submitted for market days up to seven days in the future, they are most commonly submitted in association with offers into the day-ahead (DA) and real-time (RT) energy markets.[86] FPA requests for the DA market must be submitted by the close of day-ahead market window (10:00 AM Eastern Time), while FPA requests for the RT energy market can be submitted up to 30 minutes before the start of the operating hour in which they would take effect.

While the automated processing of FPAs increases the participant's ability to reflect their costs through supply offers rather than after-the-fact uplift payments, it comes with an obligation of verification. To lessen this concern and the ability of a participant to exercise market power, the IMM has two tools: an ability to set a limit on requested FPA prices, and cost verification through *ex-post* documentation.

The IMM uses a proprietary model to estimate a reasonable upper bound for natural gas prices ("FPA Limit"). More specifically, the model uses a variety of forecasting techniques to create probabilistic estimates of pipeline-specific natural gas prices paid by generators for next day and same day delivery of natural gas. The model uses data on regional natural gas transactions from the Intercontinental Exchange (ICE), actual and forecasted weather, and load.

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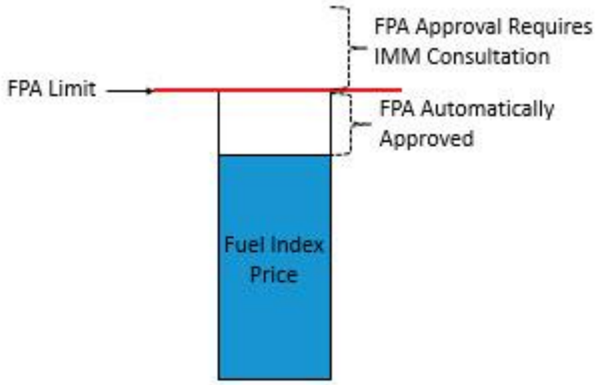
[84] See *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.7.5, available at [https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.](https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf)

[85] Similar formulae are also used to estimate no-load and start-up costs, but are not shown here to preserve space.

[86] The software suspends the processing of FPA requests for market days greater than one day out until the beginning of the day before the requested market day.

Once submitted, the system either approves the FPA at the requested price or caps it at the FPA Limit (see Figure below). As outlined in III.A.3 of the Tariff, if a participant's fuel cost expectation exceeds the FPA Limit, they may consult with the IMM to provide additional documentation for the increased cost. The IMM will draw on its visibility into all FPA requests as well as ICE bids, offers, and transactions to either: 1) manually approve the participant-specific FPA request; 2) raise the FPA limit to more accurately reflect market conditions; or 3) keep the FPA request capped.

FPA Processing Overview



In addition to this *ex-ante* measure, the IMM requires that within five business days of the FPA submittal, the participant must provide supporting documentation in the form of an invoice or purchase confirmation, a quote from a named supplier, or a price from a publicly available trading platform or reporting agency. Should the participant fail to provide this documentation, it can lose the right to use the FPA mechanism (per Section III.A.3.4 of the Tariff).