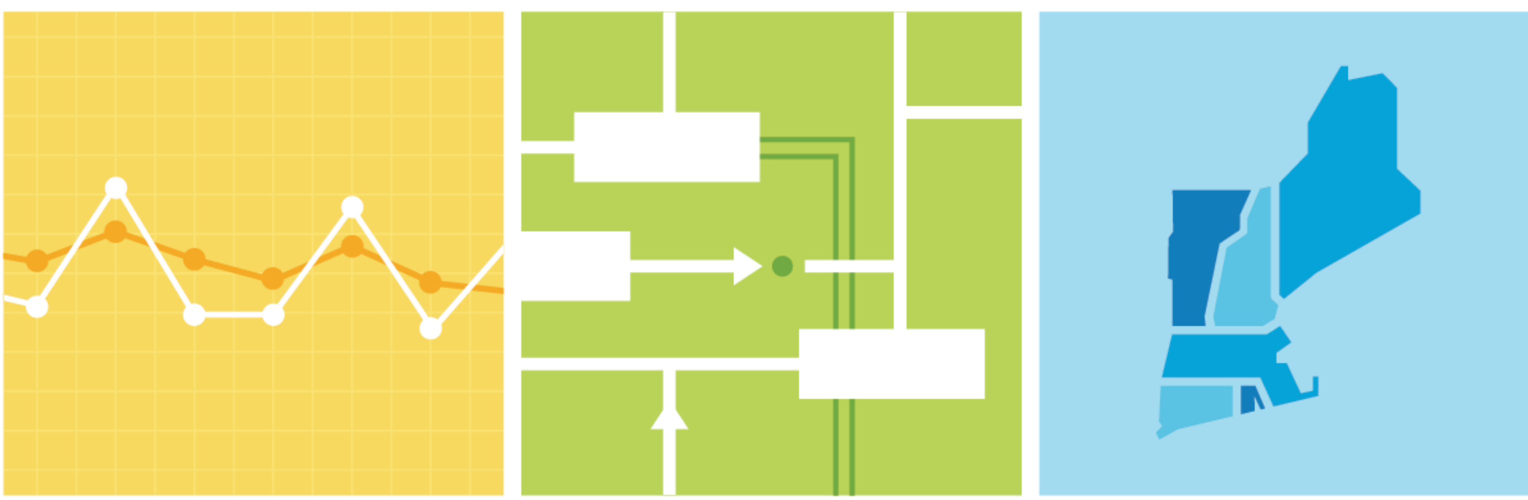
Winter 2024
Quarterly Markets Report

By ISO New England's Internal Market Monitor

MAY 31, 2024



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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.

[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 2024 (December 1, 2023 through February 29, 2024).[3]

Winter Assessment: New England weather was mild in Winter 2024, and there were no significant reliability events, system events, or fuel availability issues in the region. The lowest hourly temperature for the season was the warmest of any winter since 2002, and peak winter load was the lowest since at least the year 2000. Below are highlights of the supply mix, fuel markets, and other winter outcomes.

- Winter 2024 saw the lowest natural gas prices and LMPs of all winter seasons since 2020.
- There were no significant gas system issues, and reliance on oil generation was minimal (0.2% of total supply); Oil inventories remained relatively unchanged throughout the winter.
- Total liquefied natural gas injections into New England pipelines (LNG sendout) more than doubled from Winter 2023 as LNG prices fell to $12.90/MMBtu.
- The tightest gas market conditions occurred from January 14-22. Natural gas prices, fuel price adjustment (FPA) request prices, and LNG sendout peaked during this period.
- The spread between average fuel price adjustment (FPA) requests and settled index prices decreased compared to the prior winter, largely due to the lack of extremely cold weather.
- No significant mitigation events occurred during this winter.
- Energy market opportunity cost (EMOC) estimates for oil-fired generators were zero and therefore did not impact energy market reference levels used for market power mitigation; this outcome is consistent with fewer economic opportunities to burn oil that would otherwise constrain inventories.

Inventoried Energy Program: This was the first winter of the Inventoried Energy Program (IEP). The total cost of the IEP during Winter 2024 was $79 million, about 4% of total wholesale market costs.

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

- Oil inventories at the beginning of this winter exceeded last year by 10%, despite less favorable forward winter prices, with the increase attributable to resources in the IEP.
- The equivalent of 4,800 MW (345 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 $78.8 million (~4% of wholesale market costs), which were 42% lower than the estimated upper bound cost, due to lower participation than the upper bound estimate.
- The impacts of IEP on other markets are likely small and any impact analysis is assumption heavy. First, IEP did not appear to affect energy prices, as winter

[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).

conditions did not create additional opportunity costs for IEP participants to conserve fuel. Second, to the extent that participants reflected net IEP revenues in capacity market bids, there was a potential increase in cleared energy secure resources in FCA 14, and lower capacity prices and payments, by as much as $186 million.
- 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 $2.07 billion, down 39% from $3.39 billion in Winter 2023. The decrease was driven by lower energy and capacity costs in Winter 2024.

Energy costs totaled $1.63 billion; down 62% (or $1.01 billion) from Winter 2023 costs. Lower energy costs were a result of lower natural gas prices, which decreased by 47% relative to Winter 2023 prices.

Capacity costs totaled $259 million, down 38% (by $156 million) from last winter. Beginning in Summer 2023, lower capacity clearing prices from the fourteenth Forward Capacity Auction (FCA 14) led to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate for all new and existing resources was $3.80/kW-month. This year, the payment rate for new and existing resources was lower, at $2.00/kW-month. The price decrease was driven by a lower Net Installed Capacity Requirement (down by 1,260 MW) and higher surplus capacity (up 375 MW) in FCA 14 compared to FCA 13.

In early 2019, the Mystic 8 and 9 generators sought to retire through the capacity market but were retained for reliability by the ISO. In June 2022, the generators began receiving supplemental payments to offset operating costs per their cost-of-service agreement (Mystic CoS) with the ISO.[4] These payments totaled $75 million in Winter 2024. Mystic 8 and 9 will receive supplemental payments until the end of May 2024.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $48.66 and $44.39 per megawatt hour (MWh), respectively, a 38% and 44% decrease compared to Winter 2023 prices.

- Natural gas prices averaged $4.87/MMBtu in Winter 2024, down 47% compared to $9.15/MMBtu during the prior Winter.
- Average real-time prices in Winter 2024 ($44.39/MWh) were lower than average day-ahead prices ($48.66/MWh) primarily due to several days that saw large volumes of real-time solar generation output, resulting in low midday real-time prices. In many of these instances, actual solar output was greater than forecasted. To a lesser extent, other factors also contributed to lower prices during certain hours throughout the quarter, such as additional real-time self-scheduled generation from generators that were returning from outage earlier than expected.

[4] Under the Mystic CoS, Mystic 8 and 9 have an Annual Fixed Revenue Requirement (AFRR), which is the amount they need to operate for the commitment period. Revenues earned in the ISO-administered wholesale markets are not enough to cover the AFRR, and the supplemental payments fill the gap. Any additional revenues they receive are netted so revenues are capped at the AFRR.

- Day-ahead and real-time energy prices continued to trend in the same direction as natural gas prices. However, during Winter 2024, generator outages and a decline in net imports partially offset the downward pressure of lower gas prices on energy prices. Year-over-year nuclear generation was down by 242 MW on average per hour due to unplanned outages in December and January, and the system Total-30 reserve margin decreased by 430 MW compared to the previous winter due to a 467 MW increase in pumped-storage generator outages. Net imports fell by 148 MW in Winter 2024 compared to Winter 2023.
- Energy market prices did not differ significantly among the load zones.

The Eighteenth Forward Capacity Auction (FCA18): The eighteenth Forward Capacity Auction (FCA 18) was held in February 2024 and covers the capacity commitment period (CCP) beginning June 1, 2027 through May 31, 2028. Below are highlights from the auction.

- There was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (NICR).
    - Qualified capacity (36,560 MW) exceeded NICR (30,550 MW) by 6,010 MW.
    - System-wide surplus capacity cleared 1,006 MW above NICR.
- The entire system cleared at $3.58/kW-month, a price below which the IMM reviews bids from existing capacity resources for the purposes of market power mitigation. There was no price separation between capacity zones and interfaces in FCA 18.
- Expected payments for FCA 18 ($1.3 billion) increased by 37% from the record-low payments projected for FCA 17 ($0.9 billion). This increase was likely driven by the outward shift in the system demand curve due to a significant increase in the Net Cost of New Entry and also a small increase in forecasted load as reflected in NICR.
- Based on our pre-auction review of de-list bids, excess capacity before and during the auction, and the liquidity of dynamic de-list bids, it is our opinion that auction outcomes were the result of a competitive process.
- A total of 2,474 MW of capacity de-listed in FCA 18. Over 1,200 MW of oil-fired generation de-listed, with 768 MW permanently retiring from the energy and capacity markets.
- New entry of capacity totaled 1,142 MW, primarily consisting of battery storage projects (741 MW), wind projects (185 MW), and passive demand response (105 MW).
- The substitution auction following FCA 18 did not take place as no active demand bids were entered.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $9.2 million, a 26% decrease compared to Winter 2023 payments of $12.4 million. NCPC payments represented 0.6% of total wholesale energy costs in Winter 2024, consistent with historical levels.

- Almost all NCPC (99%) was in the economic category, which includes payments to resources providing first-contingency protection and payments to resources operating below their economic dispatch point (opportunity cost payments) at the instruction of the ISO.
- Most economic payments (87%) occurred in the real-time market.
- Distribution payments and performance audit uplift made up the remainder of NCPC.

Real-time Reserves: Real-time reserve payments totaled $2.9 million, a substantial decrease compared to Winter 2023 ($6.5 million), as no shortage event occurred during Winter 2024. Most reserve payments went to resources providing TMSR (59%), while smaller portions went to resources providing TMNSR (29%) or TMOR (12%). While TMNSR and TMOR prices were non-zero more frequently than in prior winter seasons, their average prices during these periods remained relatively low, particularly compared to Winter 2023, when reserve shortages resulted in capacity scarcity conditions on December 24, 2022.

Regulation**:** Total regulation market payments were $5.7 million, down 52% from $12.1 million in Winter 2023. The decrease resulted primarily from lower capacity prices. Capacity prices decreased due to lower energy market opportunity costs, reflecting a decline in energy market LMPs compared to last winter.

Financial Transmission Rights: FTRs were fully funded in December 2023, January 2024, and February 2024. Most congestion-related totals in Winter 2024 moved in line with the day-ahead energy price. Day-ahead congestion revenue was $11.8 million in Winter 2024 (0.7% of energy costs), down 43% relative to Winter 2023. Positive target allocations ($12.0 million) followed a similar pattern, decreasing by 32% compared to Winter 2023. Negative target allocations ($1.1 million) decreased by 26% from their Winter 2023 level. Real-time congestion revenue remained relatively modest and was generally in line with recent historical levels. At the end of February 2024, the congestion revenue fund had a surplus of $1.2 million.

Section 2
Assessment of Winter 2024 Market Issues

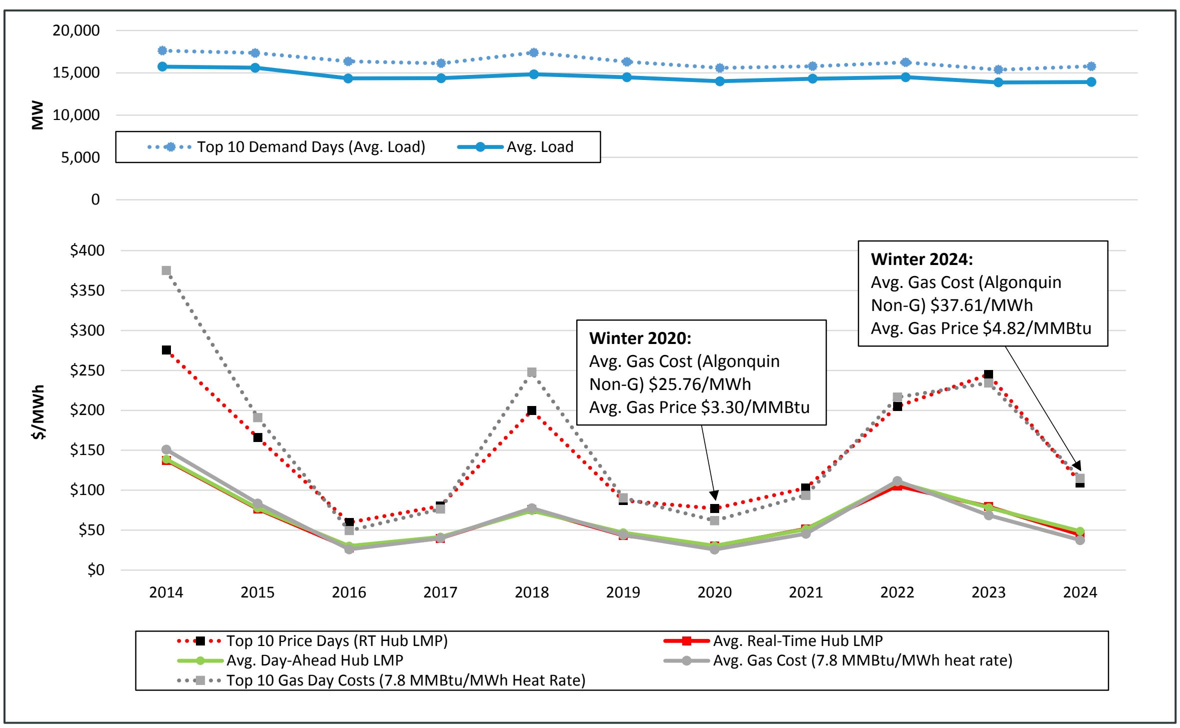
This section focuses on winter-specific issues in the New England markets. During winter in New England, increased heating demand for natural gas can cause pipelines to become constrained, giving rise to high natural gas prices. As temperatures fall, natural gas heating demand increases and natural gas-fired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

The 2023/24 New England winter was mild and there were no significant reliability events, system events, or fuel availability issues in the region. Peak winter load was the lowest since at least the year 2000, and the low temperature for this winter season was the mildest of any winter since 2002. Stored fuels were not constrained—oil was only in economic merit order one day over the winter so inventories remained stable throughout the three months. Winter 2024 was the first 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 $79 million, about 4% of total wholesale costs.

2.1 Market Drivers and Price Summary

Winter 2024 saw the lowest natural gas prices and LMPs of all winter seasons since 2020. 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[5], and Loads

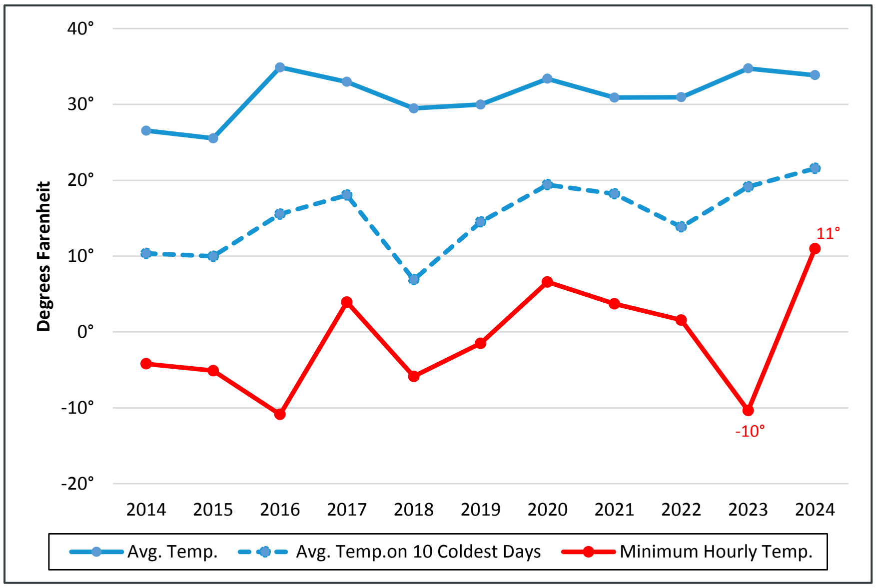


[5] Due to data limitations, this graph uses Algonquin Citygates (before January 2016) and Algonquin Non-G (after January 2016) prices rather than the IMM trade-weighted value referenced elsewhere in the report.

Winter LMPs have varied widely between 2014 and 2024. Average day-ahead and real-time LMPs in Winter 2024 ($48.66/MWh and $44.39/MWh) were the seventh highest in the last 11 winters. The average real-time LMP on the top ten high-priced days in Winter 2024 ($109.33/MWh) followed a similar pattern. Additionally, average reserve prices were in line with other winter periods. Average loads on the top ten demand days (15,781 MW) were similar to that of Winter 2020 and 2021, but lower than that of Winter 2014-2019.

Historical temperature data is shown in Figure 2-2 below.

Figure 2-2: Winter Average and Minimum Temperatures



Temperatures averaged 34°F in Winter 2024, which was similar to Winter 2023 and the third warmest winter since Winter 2014. Additionally, the Winter 2024 minimum hourly temperature (11°F) and average temperature on the ten coldest days (22°F) were warmer than in any other period since 2014. Other recent winters have also been mild on average, but typically saw at least some hours with very cold temperatures. For example, even though the average temperature in Winter 2023 was 35°F, there were still days where hourly temperatures dropped below 0°F. The last time a winter season saw such a mild minimum temperature was Winter 2002.

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. However, in Winter 2024, with mild weather conditions throughout the season, there were no significant gas system issues and minimal reliance on oil generation.

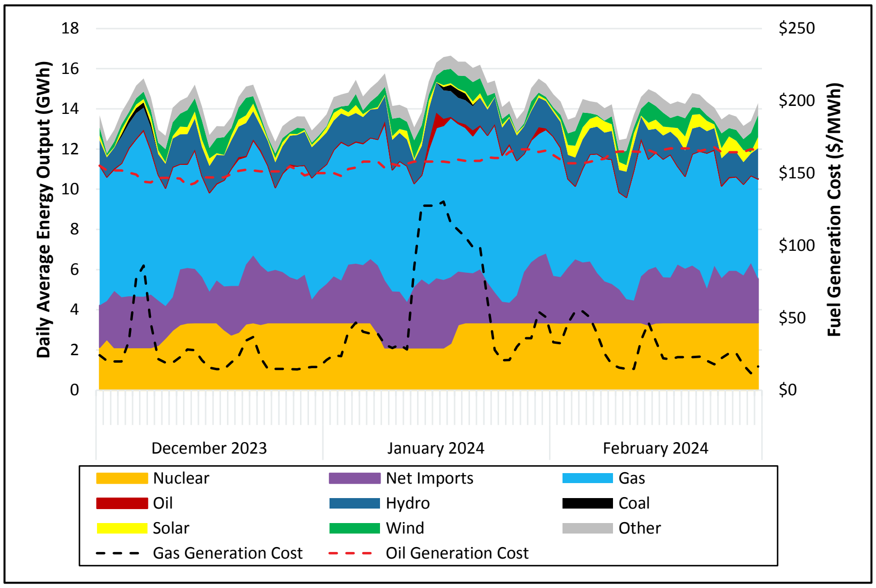
The following subsections discuss the supply mix, fuel inventory, and the natural gas market, with a special focus on winter outcomes.

2.2.1 Supply Mix

The real-time supply mix in New England during Winter 2024 predominantly consisted of power from gas-fired generation, nuclear generation, and power flowing from neighboring control areas (together making up 82% of total supply).[6] Estimated generation costs for natural gas remained below estimated generation costs for oil, and much less oil-fired generation was dispatched than in recent winters.[7]

The relationship between natural gas prices and oil generation can be seen in Figure 2-3, 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 2024 (left axis).[8]

Figure 2-3: Real-Time Generation Obligation by Fuel Type and Gas/Oil Price



Daily natural gas generation cost exceeded $100/MWh for seven days on January 14 through January 20. Oil-fired generation during this seven-day period accounted for 52% of the oil burned throughout the season, the lowest total amount of winter oil burn since Winter 2019. In aggregate, oil-fired generation accounted for just 0.2% of the energy produced during Winter 2024.

Wholesale solar generation set winter record highs in 2024, with average output of 262 MW per hour (2% of total supply). The increase in wholesale solar generation was driven by installed capacity growth, with 3,466 MW of wholesale capacity in Winter 2024, up 12% from Winter 2023. As discussed in Section 0, both wholesale and behind-the-meter (BTM) solar generation grew significantly from prior winters as installed capacity growth exceeded 2024 forecasts, leading to

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[6] As discussed in Section 0, nuclear generation, gas-fired generation, and net imports accounted for 82% of total energy production in Winter 2024.

[7] An illustration of oil dispatch during that winter season can be found in our *Winter 2023 Quarterly Markets Report* (May 30, 2023), Section 2.2.1, available https://www.iso-ne.com/static-assets/documents/2023/05/2023-winter-quarterly-markets-report.pdf

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

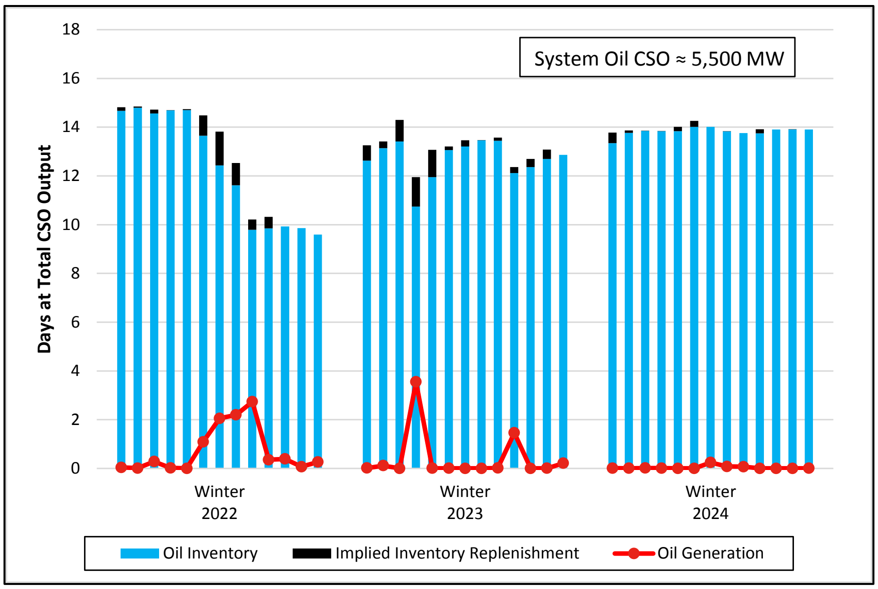
higher estimated BTM output and contributing to lower energy prices in Winter 2024 relative to prior winters.

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 snapshot 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 2-4 below show's weekly-aggregated fuel oil inventory expressed in terms of days of generation for oil capacity with a Capacity Supply Obligation (CSO), and includes estimated oil inventory replenishments that occurred throughout the winter.[9]

Figure 2-4: Winter Fuel Oil Inventories



Oil inventories remained relatively unchanged throughout Winter 2024, with little oil usage or replenishments due to mild weather conditions. At the beginning of the season, roughly 14 days of generation output was available (equivalent to 1,800 GWh of inventory converted to energy at 5,500 MW per hour). Inventories remained stable throughout the winter, with a total of 61 GWh of oil generation and 148 GWh of replenishment. Oil generation fell significantly in Winter 2024 relative to both Winter 2023 (715 GWh) and Winter 2022 (1,257 GWh). In Winter 2022, about ten

[9] 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 2022-2024, the system total CSO for oil-fired generators was approximately 5,500 MW. For reference, Winter 2024 loads averaged 13,927 MW; at full output and with sufficient inventory, oil resources could comprise roughly 40% of average daily load. 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.

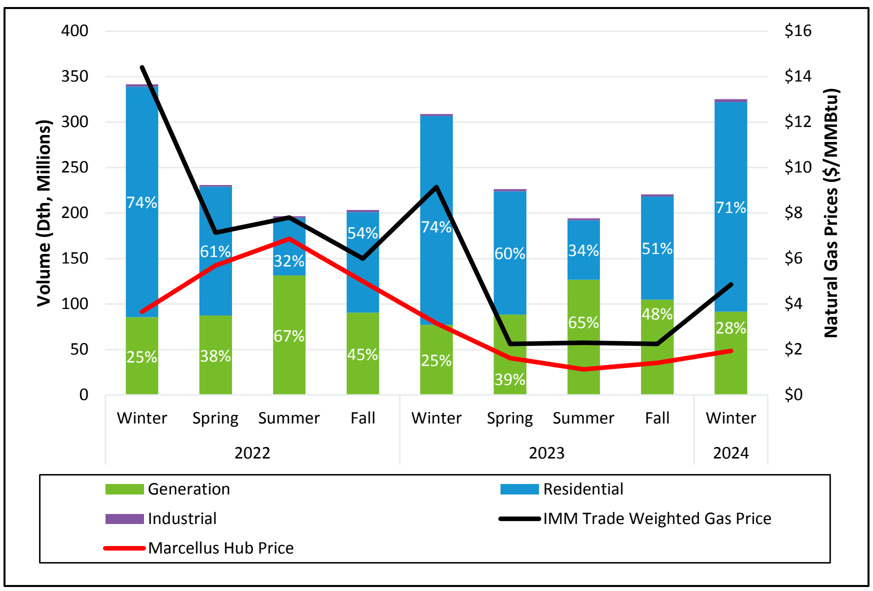
days of oil inventory were used for generation and five days of generation were replenished, resulting in ten days of inventory at the end of the season.

While the above analysis aggregates all oil generators, there is significant variation in inventories among stations.[10] Oil inventory is relatively concentrated within a few stations, with the four stations with the most inventory comprising 49% of total inventory on average in Winter 2024. The concentration of oil inventories in a few stations poses potential operational risks. Notably, generators at each of the four largest oil stations are considered by the ISO to be at risk of retirement, and all generation at one of the top four stations is planned for retirement, affecting up to 12% of Winter 2024 oil inventories. The New England oil-fired generation fleet has an average age of 49 years, and older generators might have reduced operational flexibility and increased risks of unplanned outages during periods when the system might otherwise rely on oil generation.[11]

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 2-5 below.[12]

Figure 2-5: Natural Gas Demand by Sector



Natural gas pipeline demand reached 325 Dth in Winter 2024, up 5% from Winter 2023. Total residential gas demand (231 Dth) was similar to Winter 2023. The increase in total demand was driven by the generation sector (up 19% increase) as natural gas prices fell and gas-fired generation was economic more frequently than in prior winters. Natural gas prices averaged $4.87/MMBtu during the winter, the lowest winter gas price over the three years. With few periods

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

[11] The average oil-fired generator age is calculated as a weighted average by generator capacity.

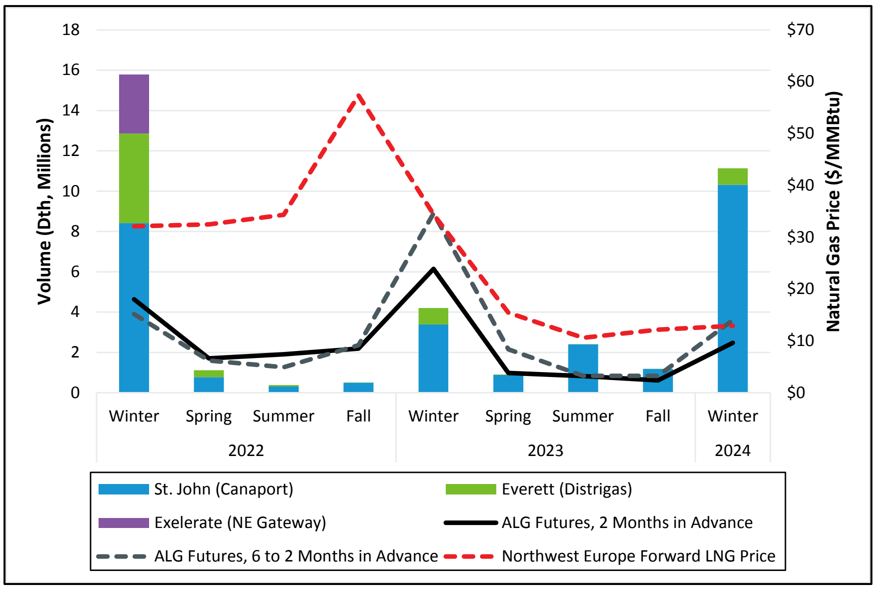
[12] Natural gas demand from the industrial sector is shown, but the sector only procures around 1% of gas demand in every quarter. All natural gas demand and LNG sendout data are sourced from *Wood Mackenzie*, available at https://www.woodmac.com/.

of extreme cold or constrained pipeline conditions, winter spreads between New England and Marcellus Hub prices fell significantly from the prior two winters (by 51% from Winter 2023 and 73% from Winter 2022).

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. There are three operational LNG import facilities that inject gas into New England: Excelerate, Saint John (formally Canaport), and Everett (Distrigas).[13] The volume of injections (sendout) into the interstate pipelines from each facility for the past three years is illustrated in Figure 2-6 below. The lines (right axis) show the forward prices for LNG contracts for Northwest Europe LNG and Algonquin Citygates (ALG) futures prices at different intervals before the delivery period.[14]

Figure 2-6: LNG Sendout by Facility



LNG sendout increased in Winter 2024 relative to Winter 2023, totaling 11.1 million Dth. This sendout is equivalent to 640 MW per hour of standard-efficiency gas generation for the winter.[15] Despite low gas prices, total LNG sendout more than doubled from Winter 2023 as LNG prices fell to $12.90/MMBtu. LNG shipment contracts are often made well in advance of delivery. As shown above, Algonquin Citygates futures prices for Winter 2024 traded at $14.04/MMBtu between two

[13] 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.

[14] 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 and between six and two months before delivery, then aggregated to the season level through taking averages of monthly values within the season weighted by number of days.

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

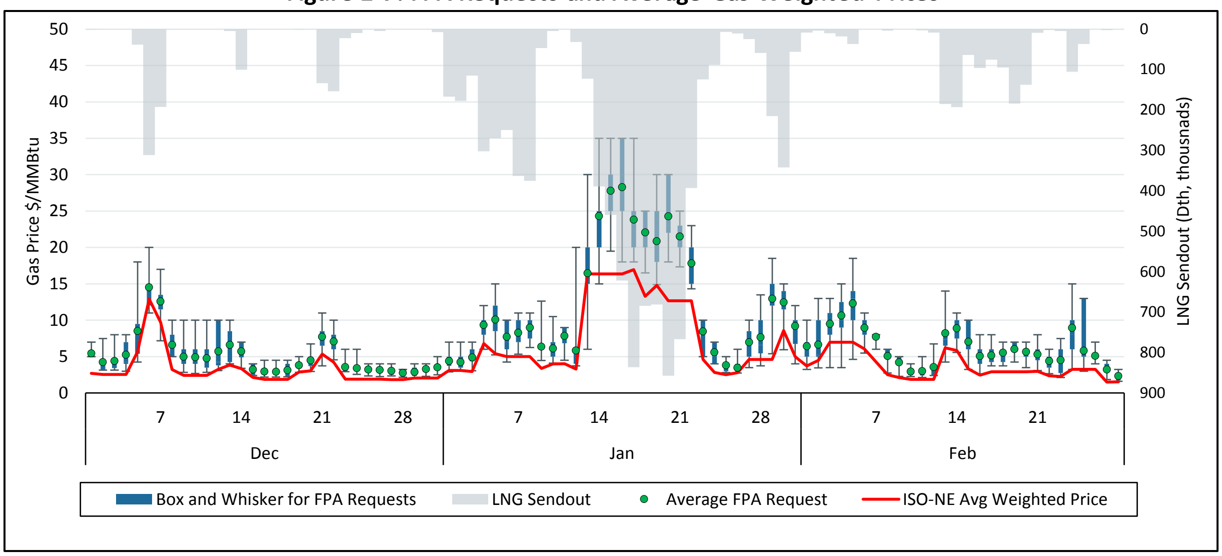
and six months before delivery, reflecting expectations that global LNG imports would be economic in New England. At two months to delivery, expectations shifted toward a mild winter, and Algonquin futures fell below LNG prices to $9.65/MMBtu. Winter 2024 LNG supply reflects the excess shipment contracts made during the period where suppliers expected LNG imports to be economic in New England as stations injected LNG at low natural gas prices to make room for incoming contracted supply.

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.[16] Many generators instead rely on short-term purchases, including next-day and same-day procurement.[17] As natural gas prices increase, short-term 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.

We compare the range of FPA requested prices (a box and whisker chart) to gas index prices in Figure 2-7 below. The figure also illustrates the relationship between the gas index price and LNG injections.[18,19]

Figure 2-7: FPA Requests and Average Gas-Weighted Prices



[16] 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).

[17] 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.

[18] 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.

[19] 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.

Increased LNG sendout to New England (gray bars) lines up with periods with the highest index prices and FPA requests, notably January 14-22. 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 14-22, LNG suppliers took advantage of favorable conditions to sell LNG, compared to less advantageous circumstances leading up to January 14-22.

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 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 2-8 below summarizes the analysis of FPA-based offer impacts on LMPs on January 14 through January 22.[20] The black line, charted on the left axis, shows the Hub LMP. Two IMM-estimated values also share the left axis:

- First, the *Supply Offers* (gray bars): the top of the gray bars show the average offer prices of generator segments that reflect approved FPAs. The bottoms of the gray bars show an estimate 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.

- 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.[21]

Finally, the *Uneconomic Output* (black bars): on the right axis, we show 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.

[20] 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 in this analysis; only committed but undispatched generation. This could result in estimated impacts lower than actual impacts.

[21] 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 2-8: Real-Time FPA Price Impacts, January 14 - January 22, 2024

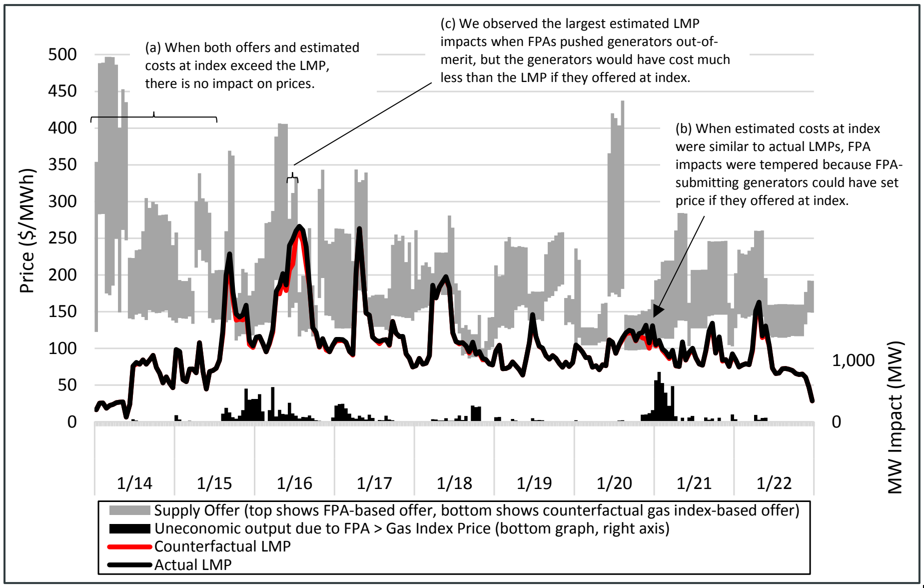


Figure 2-8 highlights a few key takeaways. First, the price impacts of FPAs were modest during the highest-priced days. This is because on most days, offers based on both FPAs and the index price were above the LMP, so offers based on FPAs would not have been in-merit if they were offered at index. Many of these offers were in generators' high-heat-rate upper offer blocks.

Second, generally, we see impacts when the top of the gray bars are above the black line, and the bottom of the gray bar is far below the black line. We estimated meaningful impacts of FPAs on LMPs on only three days: January 15, 16, and 20. On two of the three days, January 15 and 20, the impacts were small. On January 16, there were just *three* hours when FPA-based offers impacted LMPs by an average of about $30/MWh, or 13% of the hub LMP. There was a small amount of output (176 MW per hour) that was pushed out-of-merit by FPAs, on average, during the three hours (black bars at the bottom of the chart). 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.[22] 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, we calculate 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. This 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.

Due to the ample inventories of stored fuel and relatively high price of oil to natural gas during the winter, no (non-zero) EMOCs were produced. In other words, the EMOC model did not estimate that any generators would deplete their fuel inventories (or produce tradeoffs between producing energy now or in another profitable hour), because profitable hours for oil-fired generators were so uncommon.

2.4.2 Fuel Price Adjustments

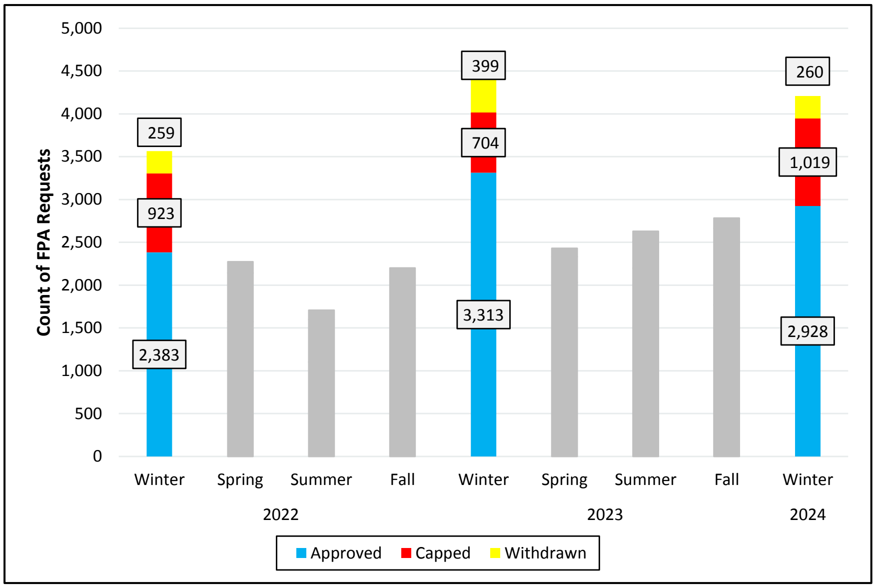
In this subsection, we provide an overview and analysis of Fuel Price Adjustment (FPA) requests for Winter 2024. Participants use FPAs to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index. As part of the FPA request assessment, we use a model to estimate a reasonable upper bound for natural gas prices ("FPA

[22] 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.

Limit").[23] For more details on how FPAs are processed, see *Appendix: Overview of FPA Process*, at the end of this report.

In Winter 2024, we received FPA requests from 18 participants for 50 generators, which is slightly lower than Winters 2022 and 2023. Figure 2-9 shows the number of FPA requests by season over the last few years.

Figure 2-9: FPA Requests, by Year, Season, and Status



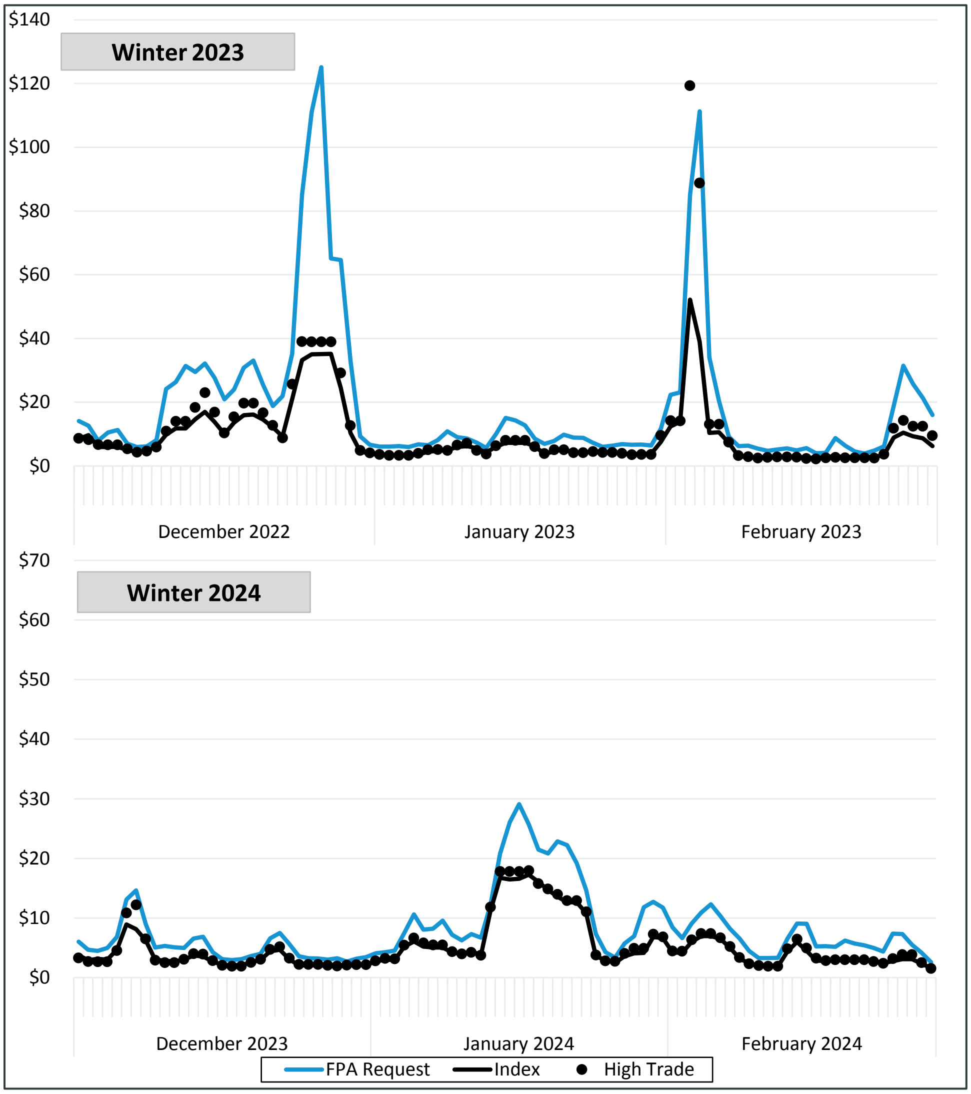
More than 4,200 FPA requests were processed during Winter 2024, an average of about 46 per day – a similar number to the prior winter. The number of FPA requests spikes in the winter compared to other seasons. This increase indicates both greater price volatility, price uncertainty, and additional factors discussed regarding Figure 2-10 below. Consistent with prior years, the majority of FPAs (~91%) were made for the day-ahead market.[24]

The following figure shows the average settled natural gas index price, average volume-weighted high-priced trade and 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.

[23] 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.)

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

Figure 2-10: Average Index Price, High Trade, FPA Request, and Effective FPA



The spread between average FPA requests and settled index prices (62%) decreased compared to the prior winter (113%). This is largely due to the lack of extremely cold weather, as discussed in Section 2.1. LNG injections kept FPA requests closer to the index price on days where non-LNG gas was limited. This reduced price volatility compared to Winter 2023, but had minimal impact on the volume of FPA requests compared to Winter 2023.

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. In Winter 2024, participants with an effective FPA offered 55% of their total capacity based on an implied fuel price below their FPA, providing an indication of the need for MW-dependent FPAs.[25] Under the current FPA submittal process, participants have limited ability to

[25] 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

capture fuel price variability when updating their reference levels. While also providing additional flexibility to participants, the ISO proposal to implement MW-dependent FPAs will improve our ability to monitor for potential instances of market manipulation and economic withholding.[26] 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 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.[27]

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 $92.51/MWh of inventoried energy sold forward,[28]
3. a spot rate: 1/10th of the forward rate, or $9.25/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,[29]
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 up 10% from last year, despite less favorable forward winter prices, with the increase attributable to resources in the IEP.
- The equivalent of 4,800 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 $78.8 million (~4% of wholesale market costs), which were 42% lower than the estimated upper bound cost, due to lower participation than the upper bound estimate.
- The impacts of IEP on other markets are likely small and any impact analysis is assumption heavy. First, IEP did not appear to affect energy prices, as winter conditions did not incentivize participants to burn stored fuel (i.e., incremental IEP revenues were not needed

[26] 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.

[27] 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.

[28] Each participant can sell up to 72-hours of inventoried energy forward.

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

to incentivize fuel conservation). Second, to the extent that participants reflected net IEP revenues in capacity market bids, there was a potential increase in cleared energy secure resources in FCA 14, and lower capacity prices and payments, by as much as approximately $186 million.

- 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 $79 million—almost entirely composed of forward payments, as shown in Table 2-1 below. The market-wide inventoried energy reported on the single IEP day this winter exceeded the forward inventoried energy by 9%, resulting in less than a million dollars of spot payments.

Table 2-1: IEP Payments by Fuel Type ($ millions)

Fuel Type	Forward Payments	Spot Payments	Total Payments	Analysis Group Upper Bound Estimate
Electric Storage	$0.2	$0.1	$0.3	$0.1
Natural Gas	$23.9	$0.4	$24.4	$54.5
Oil	$52.3	$0.2	$52.5	$75.6
Refuse	$1.7	$0.0	$1.7	$2.5
Demand Response	$0.0	$0.0	$0.0	$4.2
Total	**$78.1**	**$0.7**	**$78.8**	**$136.8**

The total cost of the IEP program was 40% lower than the $137 million upper bound cost estimated by the Analysis Group.[30] The cost difference was due mostly to a difference in expected vs. observed participation in forward component of the program (1,408 GWh of inventoried energy sold forward in upper bound estimate vs. 844 GWh of actual inventoried energy sold forward). Differences in participation are discussed below, in Section 2.5.2. The forward rate used in the upper bound estimate was also slightly higher—$97.18/MWh vs. the actual rate of $92.51/MWh.

2.5.2 Participation in the IEP

Total participation in the IEP program was 1,133 GWh—about 20% lower than the 1,408 GWh upper bound estimate provided by the Analysis Group. Forward participation of 844 GWh was about 40% lower than the same estimate. Table 2-2, below, shows a summary of IEP participation.

[30] The Analysis Group's upper bound estimate assumed that 100% of participating inventoried energy was sold forward and maintained during Inventoried Energy Days. The Analysis Group estimated the upper bound of the program's cost to be approximately $137 million for a rate of $97.18 per MWh. See *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Update the Inventoried Energy Program, Docket No. ER23- -000* (April 7, 2024), available at https://www.iso-ne.com/static-assets/documents/2023/04/updates_to_inventoried_energy_program.pdf

Table 2-2: IEP Participation

Fuel Type	Analysis Group Estimated Upper Bound GWh [1]	IEP Forward + Spot Qualified GWh	IEP Forward GWh	Percent of Qualified Sold Forward	Delivered on IEP Day GWh
Electric Storage	1	14	2	14%	11
Natural Gas	560	345	259	75%	304
Oil	778	753	565	75%	585
Refuse	26	22	18	83%	22
Demand Response	43	0	0	-	0
Total	**1,408**	**1,133**	**844**	**74%**	**922**

Note: Analysis Group assumed all inventory would be sold forward for the purposes of their estimates

Overall, generators and demand response resources that elected to participate in the IEP qualified 1,133 GWh of inventoried energy, equivalent to about 15,734 MW per hour over three days. About 74% (844 GWh) of qualified inventoried energy was sold forward, equivalent to about 11,700 MW per hour. For the January 20 inventoried energy day, participants reported 922 GWh of inventoried energy (12,807 MW per hour for three days). Only 60% of the estimated upper bound provided by the Analysis Group sold inventoried energy forward. The differences between the upper bound estimate and the realized participation are generally due to differences in forward participation, and some methodological differences within fuel types. The important differences are summarized below.

Oil-fired generators sold 565 GWh forward, the most of any fuel type. 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). However, these generators exceeded their forward elections by delivering 585 GWh on the inventoried energy day, enough inventoried energy to produce over 8,000 MW per hour over a 72-hour period. The total qualified oil inventoried energy was similar to the upper bound estimate, but only 75% of the qualified inventoried energy elected into the forward component of the program—the Analysis Group assumed 100% forward participation.

Gas-fired generators qualified 345 GWh of inventoried energy, corresponding to about 4,800 MW of firm gas per hour. About 20% of the natural gas inventoried energy was backed by an LNG contract. The remaining gas contracts were backed by pipeline gas. The upper bound estimated by the Analysis Group was based entirely on LNG supply. Additionally, similar to the oil inventory, about 75% 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. Electric storage exceeded the upper bound estimates because pumped-storage facilities were ultimately eligible to participate in IEP, but were not included in the upper-bound estimate.

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; and
- *capacity market outcomes* to determine if IEP impacted the allocation of cleared capacity across resources or auction clearing prices by lowering the revenue needed to be recovered through the capacity market.

Oil Inventories

Starting oil inventories in Winter 2024 were 1,775 GWh, 10% higher than in the previous winter, despite significantly less favorable forward market price expectations.[31] Although it is difficult to draw a causal link to the IEP, it is noteworthy that the increase is entirely attributable to IEP-participant stations, which began the winter with 170 GWh more fuel than the previous winter.[32] By contrast, non-participant stations started the winter with 6 GW less fuel compared to the previous winter.[33] However, the higher starting inventories were not adequately tested due to mild weather conditions, which limited the use of oil and thus gave little indication of Market Participants' incentives to replenish these inventories.

Energy Market Outcomes

With the mild winter and low energy prices, we estimate that IEP did not have any meaningful impact on short-term market outcomes. Natural gas pipelines were typically unconstrained and prices were relatively low. Therefore, IEP did not incentivize oil-fired generators to conserve fuel for use on an IEP inventoried energy day because these generators were generally not in merit to run.

Capacity Market Outcomes

The IEP was designed to reduce the likelihood that resources with inventoried energy pursue retirement by lowering the revenue they would otherwise seek to recover through the fourteenth Forward Capacity Auction (FCA 14). While there is no empirical evidence to suggest participants delayed resource retirements as a result of IEP, we assess the impacts on single-year dynamic de-list bids. Specifically, competitive resource bids in FCA 14 should have reflected any incremental revenues earned and costs incurred by IEP resources. The IEP-adjusted bids into the FCA should, in

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31 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 2023, forward on-peak New England Hub prices for Winter 2023-2024 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, and by a modest $2/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).

32 A "station" is a set of existing resources consisting of one or more assets located within a common property boundary.

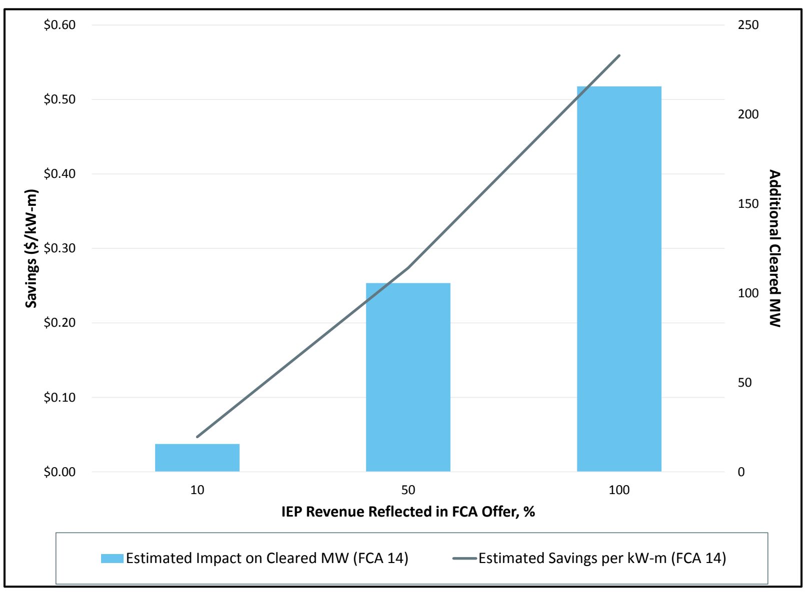
33 Approximately three quarters of the decline in starting inventories among non-participating stations is attributable to retirements or long-term outages rather than a decline in the average starting inventory at each station.

turn, affect clearing prices, overall cleared capacity, and the allocation of cleared capacity across resources.

However, FCA 14 cleared at $2/kW-month, below the dynamic de-list bid threshold, limiting the IMM's visibility into the make-up of de-list bids. We therefore analyze the potential impacts on FCA 14 under the simplifying assumption that all participating oil-fired resources anticipated earning an additional $0.57/kW-month through the program. This estimate is based on a capacity-weighted average of resource-level expected revenues provided by the Analysis Group. The estimate captures four program-related revenues and costs: (1) IEP forward payments; (2) Incremental revenue that resources may receive from higher LMPs as participating resources with limited fuel inventory increase their energy market offers to reflect the opportunity cost of generating energy in terms of foregone IEP spot payments; (3) The incremental inventory cost of securing fuel inventory for the IEP; and (4) The opportunity cost of holding real-time energy inventory to participate in the IEP, rather than participate in the energy market, in terms of the foregone net energy and ancillary services revenue.

As mentioned above, we do not have visibility into the composition of dynamic de-list bids, and therefore it is useful to assess impacts based on a range of net revenue inclusion in bids. Figure 2-11 summarizes the estimated impacts on the outcomes of FCA 14, as a function of the fraction of IEP net revenues that resources may have incorporated in their observed offers.

Figure 2-11: Estimated Impact on FCA Outcomes



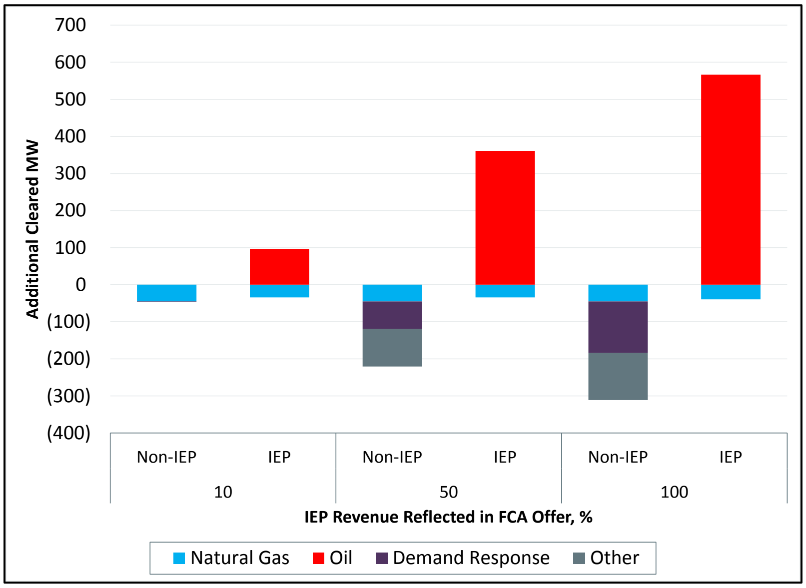
At one extreme, if observed offers reflect the full value of the estimated net IEP revenue, then, absent the IEP, FCA 14 would have concluded at a price of $2.56/kW-month (or $0.56/kW-month higher than the observed $2.00/kW-month), with commitments from 33,740 MW (or 216 MW short of the observed 33,956 MW acquired).[34] Altogether, these findings suggest that the IEP could have reduced gross FCM payments by $186 million. At the other extreme, if observed offers reflect 10% of the estimated incremental net IEP revenue, the FCA 14 clearing price would have been

[34] We use a simple market-clearing engine that attempts to maximize total surplus (the difference between FCA bids and offers) subject to a system-wide supply-demand balance constraint. We assume all offer blocks are rationable, and breaks ties among resource capacity segments with equal offer prices in favor of the smaller resource.

$0.05/kW-month higher and acquired 16 MW less in CSOs, reducing gross FCM payments by $15 million.

To gauge the potential impact on the cleared resource capacity mix, we assess the extent of the reallocation of cleared capacity among resources in Figure 2-12, which disaggregates the estimated changes in cleared capacity across technologies, distinguishing by whether a resource's underlying generators participated in the IEP.

Figure 2-12: Estimated IEP Impact on FCA #14 – Reallocation of Cleared Capacity



For example, if participants reflected 100% of IEP revenues in their capacity offers (the far right bar), 566 MW of IEP-participating oil-fired resources cleared, when they would otherwise not have without IEP revenue. That increase would have been offset by a 351 MW decline among natural gas-fired generators, hydro, demand response, and imports that did not participate in the IEP program.[35] Our analysis suggests that the IEP had some effect of allocating capacity obligations and revenues towards energy-secure resources.

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.[36] 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

[35] We estimate that some oil-fired generators acquired fewer CSO MWs than they would have, absent the IEP. These are primarily resources whose underlying generators were used for "spot-only" participation and therefore gave up the forward revenues that would otherwise have lowered their going-forward costs in the FCM.

[36] 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.

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.

Section 3
Review of the Eighteenth Forward Capacity Auction

This section presents a review of the eighteenth Forward Capacity Auction (FCA 18), which was held in February 2024 and covers the capacity commitment period (CCP) beginning June 1, 2027 through May 31, 2028. The section includes an assessment of market competiveness (including IMM market power mitigation), key auction inputs, and overall outcomes.

At the beginning of FCA 18, qualified capacity (36,560 MW) exceeded the Net Installed Capacity Requirement (Net ICR) of 30,550 MW by 6,010 MW. The auction cleared 31,556 MW of capacity, resulting in a surplus of 1,006 MW above Net ICR. The system clearing price was $3.58/kW-month and there was no price separation between capacity zones and interfaces.

Expected payments for commitment period total $1.3 billion, an increase of 37% from record-low projected payments for FCA 17 ($0.9 billion). Higher payments and auction clearing prices in FCA 18 were largely driven by an outward shift in the system demand curve due to an increase in the Net Cost of New Entry (up 23%) and a slight increase in forecasted load and NICR (up 1%).

A total of 2,474 MW of capacity de-listed in FCA 18, consisting of 1,602 MW of dynamic, one-year de-lists.[37] Over 1,200 MW of oil-fired generation de-listed during FCA 18, with 768 MW permanently retiring from the energy and capacity markets. New entry of capacity totaled 1,142 MW, primarily consisting of battery storage projects (741 MW), wind projects (185 MW), and passive demand response (105 MW). The substitution auction following FCA 18 did not take place as no active demand bids entered.

3.1 Review of FCA 18 Competitiveness

We review competitiveness both before and after the FCA. Prior to the auction, certain bids and offers can be mitigated to IMM-determined values if they are inconsistent with a resource's capacity costs. After the auction, we review competitive conditions during the auction and participant bidding behavior in order to evaluate the potential exercise of market power. Based on the pre-auction costs reviews and mitigation work, excess capacity during the auction, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 18.

Prior to the auction, 519 MW of general static de-list bids from four resources were subject to an IMM cost review. Given the absence of pivotal suppliers (described below), no de-list bids were mitigated in FCA 18. Furthermore, while the IMM reviewed 836 MW of retirement bids, the IMM did not mitigate any retirement de-list bids that entered FCA 18.

In FCA 18, we reviewed just 67 MW of new supply offers from 11 resources. The offer floor prices of all 11 resources were mitigated up. When a new supply offer is mitigated to a higher price, it limits the ability of suppliers to exhibit buyer-side market power through clearing price suppression. IMM

[37] A dynamic de-list bid is a one year de-list bid submitted at a price below the Dynamic De-list Bid Threshold (DDBT), which was $3.84/kW-month in FCA 18. Dynamic de-list bids are not subject to mitigation from the IMM.

mitigation of new supply offers decreased significantly from last year due to lower Offer Review Trigger Prices (ORTPs) for most technology types.[38]

Pivotal Supplier Test (PST) and Residual Supply Index (RSI): For FCA 18, we conducted the PST at the system level prior to the start of the auction. In order to be pivotal system-wide, a supplier would have needed an effective capacity portfolio of approximately 3,300 MW; no suppliers met this criterion at the system level.

The RSI was measured for the entire system using the Net ICR as the demand benchmark. The RSI in FCA 18 was 101%, slightly below the 102% RSI in FCA 17. RSI values above 100% indicate fewer opportunities for pivotal suppliers and seller-side market power.

Intra-Round Activity: The auction entered the fourth round with 2,031 MW of excess capacity at the dynamic de-list bid threshold (DDBT) price of $3.84/kW-month. We do not perform cost reviews of de-list bids below the DDBT because the threshold represents the anticipated, competitive clearing price of the auction. The low volume of pivotal supplier de-list bids combined with the bid prices occurring below the DDBT makes the exercise of supplier-side market power unlikely.

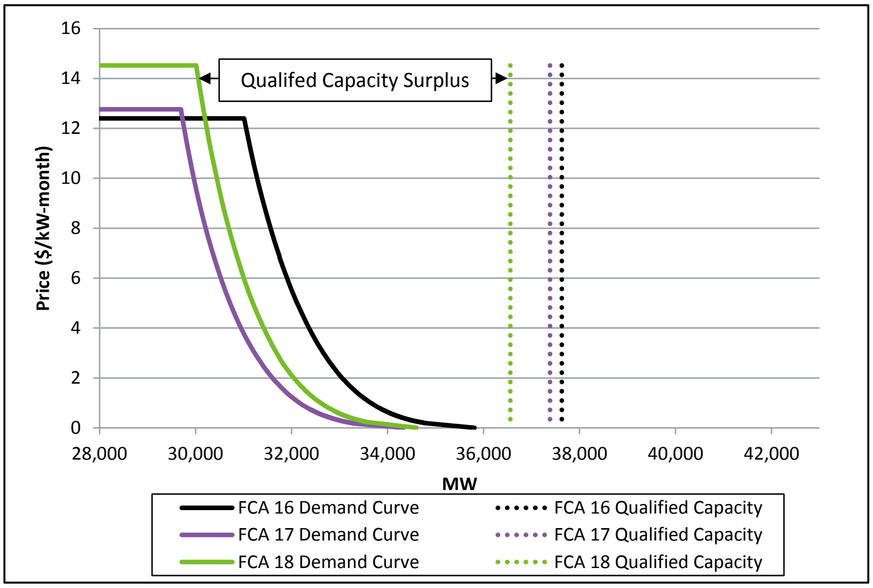
3.2 Auction Inputs

The sloped demand curve uses a Marginal Reliability Impact (MRI) methodology to estimate how an incremental change in capacity affects system reliability at various capacity levels.[39] The difference between demand curves and qualified capacity for FCAs 16, 17, and 18 are shown in Figure 3-1 below.

[38] The ISO calculates Offer Review Trigger Prices as the minimum capacity price a new resource would need to be economic in New England's energy market. ORTP data are sourced from the ISO's *Forward Capacity Market Parameters* spreadsheet (Revised date: March 31, 2023), available at https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx.

[39] The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE"). For more information on why the ISO implemented a sloped demand curve, see our *2019 Annual Markets Report* (June 9, 2020 – Revision 1), Section 6.1, available at https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf.

Figure 3-1: Net ICR and System Demand Curves



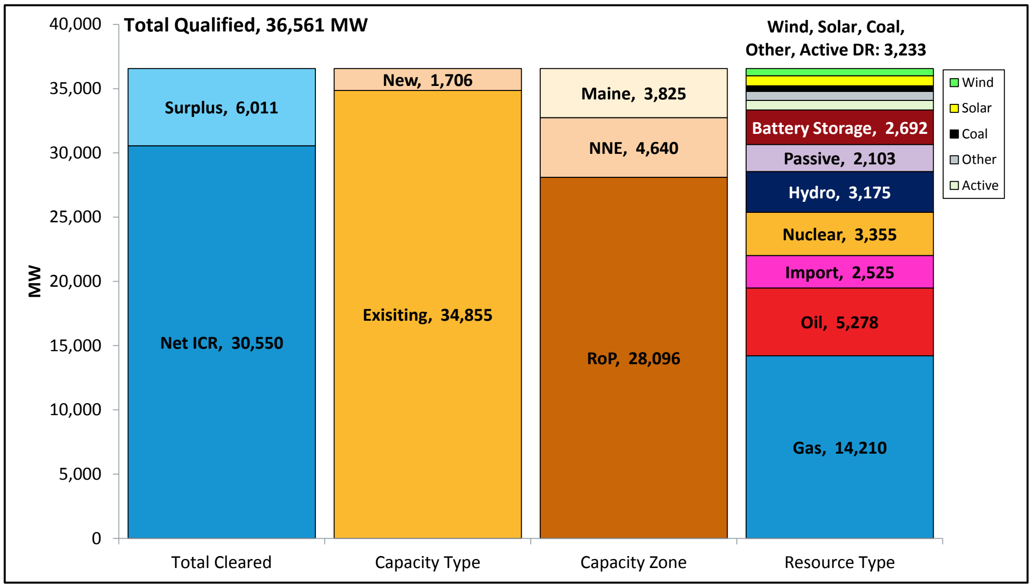
The Net Installed Capacity Requirement (Net ICR) and Net Cost of New Entry (Net CONE) are used as the scaling points for the MRI curve. The Net CONE for FCA 18 was $9.08/kW-month, up 23% from FCA 17 ($7.47) due to increasing capital costs, and reflects the breakeven capacity payment needed to cover the fixed costs of a new combustion turbine, which was selected as the most economically viable resource in the FCA 16 Net CONE study.[40] The Net ICR value for FCA 18 was 30,550 MW, slightly higher than the 30,305 MW Net ICR in FCA 17. The increase was driven by higher future load forecasts and an increase in expected forced outages for import capacity resources.[41] In FCA 18, qualified capacity saw a decrease of only 825 MW compared to FCA 17, primarily due to a reduction in existing qualified capacity.

Figure 3-2 below provides a breakdown of the 36,560 MW of qualified capacity in FCA 18. The three bars to the right show the breakdown of total qualified capacity across three dimensions: capacity type, capacity zone and resource type.

[40] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See *Section III Market Rule 1: Standard Market Design*, Section III.13.2.4, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf. The study composed for the updated FCA 16 Net CONE calculation can be found in the *ISO New England Inc., Docket No. ER21-_____-000; Updates to CONE, Net CONE, and Capacity Performance Payment Rate* document (December 31, 2020), available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf.

[41] See *Proposed Installed Capacity Requirement (ICR) and Related Values For Forward Capacity Auction (FCA) 18 (associated with the 2027-2028 Capacity Commitment Period)* (August 23,2023) by Helve Saarela and Manasa Kotha, available at https://www.iso-ne.com/static-assets/documents/2023/08/a03_2023_08_23_pspc_proposed_icr_related_values_for_fca18_final.pdf

Figure 3-2: Qualified Capacity across Capacity Type, Zones, and Resource Type



Overall, in FCA 18, qualified capacity exceeded Net ICR by 6,011 MW, or 20%. The first orange bar (by Capacity Type) shows that the qualified capacity from existing resources exceeded the Net ICR by 4,305 MW.[42]

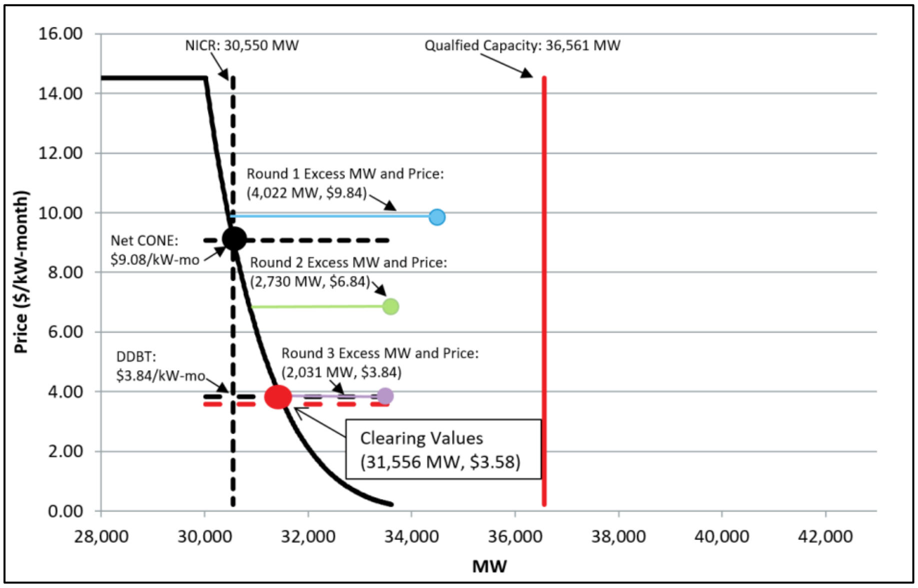
The second orange bar (by Capacity Zone) shows the Northern New England (NNE) capacity zone had 8,465 MW of qualified capacity, 294 MW less than the maximum capacity limit (MCL) of 8,760 MW for the zone. Maine, modelled as an export-constrained zone nested within NNE, had 3,825 MW of qualified capacity, below its MCL of 4,150 MW. The final bar breaks down qualified capacity by resource fuel type.

3.3 Auction Results

In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black. On the *supply* side, the qualified and cleared capacities are shown as solid and dashed red lines, respectively. The clearing price of $3.58/kW-month can be seen at the intersection of the cleared MW (dotted red line) and the demand curve (solid black line) and right below the Dynamic De-list Bid Threshold (DDBT) price of $3.84/kW-month. Lastly, the blue, green and purple markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.

42 While certain imports are classified as new for other purposes in the FCA, the IMM treats all qualified and cleared imports as existing for this report because there were no import resources in FCA 18 that increased New England's import capability. See *Section III Market Rule 1: Standard Market Design*, Section III.13.1.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

Figure 3-3: System-wide FCA 18 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces. The fourth round opened with 2,031 MW of excess capacity at the system level (purple dot) and a price equal to the DDBT price, meaning existing resources could submit dynamic de-list bids to exit the market.[43]

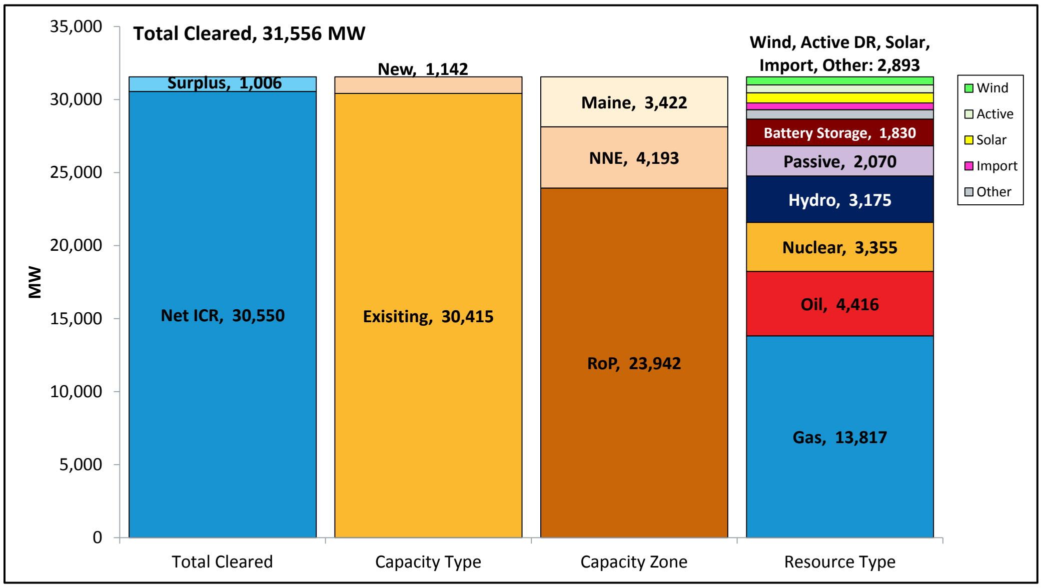
In the fourth round, bids from existing resources (including imports) totaled 2,675 MW, of which 697 MW cleared (received a CSO) and 387 MW of import resources submitted bids. A dynamic de-list bid priced at $3.58/kW-month set the auction clearing price for all capacity zones.

[43] Excess system capacity only includes import capacity up to the capacity transfer limit. Given the surplus capacity conditions associated with prices below the dynamic de-list bid threshold, it is difficult for a participant to profitably exercise market power. Therefore, dynamic de-list bids are not subject to IMM cost review or mitigation.

3.4 Cleared Capacity

Cleared capacity across several dimensions including capacity type, capacity zone, and resource type is shown in Figure 3-4 below. The height of each grouping equals total cleared capacity. As indicated in the first column, the amount of cleared capacity in FCA 18 exceeded system-wide requirements.

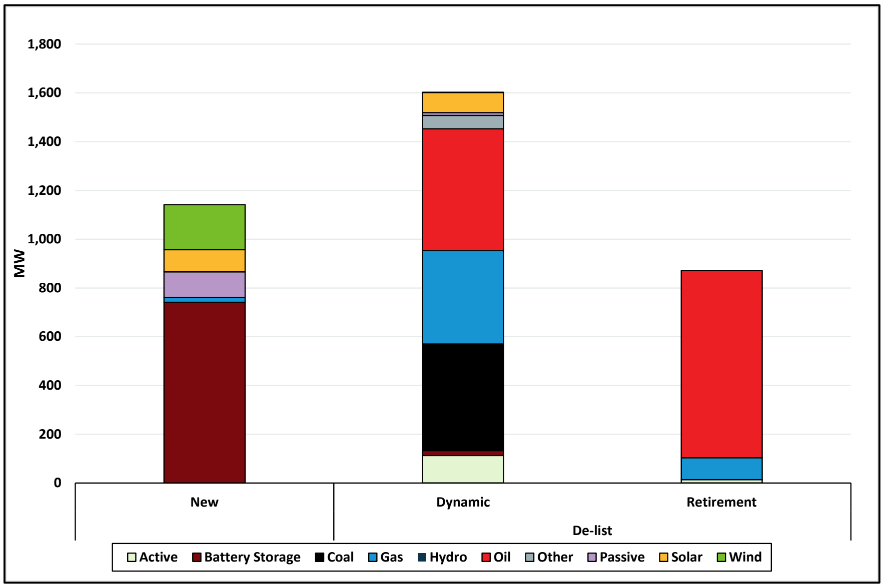
Figure 3-4: Cleared Capacity across Capacity Type, Zones, and Resource Type



As excess supply declined during the auction, total surplus relative to Net ICR fell from 6,011 MW of qualified capacity to 1,006 MW of cleared capacity. The first orange bar (capacity type) illustrates that existing capacity accounted for 96% of cleared capacity. The second set of orange bars (by Capacity Zone) shows NNE cleared 7,615 MW and Maine cleared 3,421 MW of capacity, both below their respective Maximum Capacity Limits. The final bar (by Resource Type) illustrates that gas-fired resources made up the largest portion of total cleared capacity at 44%. Battery storage projects increased their capacity share to 6% (1,830 MW), nearly double the capacity share in FCA 17.

New and de-listed capacity by resource type is broken down in Figure 3-5 below. De-listed capacity comprised of all existing generation that exited the auction for either one year (static, dynamic) or all years (permanent, retirement). De-listed capacity does not include import resources as they do not bid into the auction as existing resources.

Figure 3-5: New and De-Listed Capacity by Resource Type



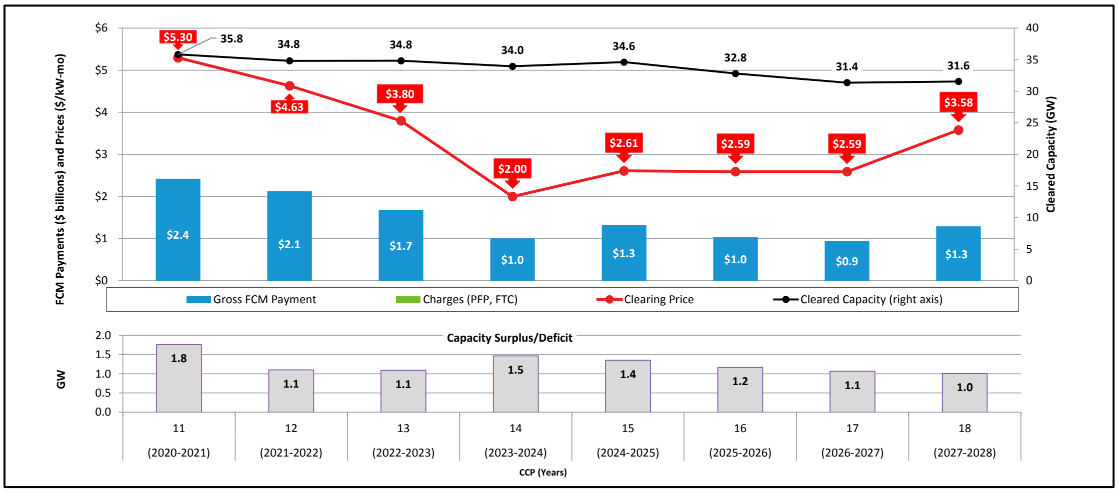
Oil-, gas-, and coal-fired resources made up the largest percentage of de-listed capacity, with 768 MW of oil-fired resources comprising most of the retirements. The dynamic de-list bid threshold was $3.84/kW-month in FCA 18; below the threshold, any existing resource can submit a one-year dynamic de-list bid without mitigation review. In FCA 18, 1,602 MW of capacity dynamically de-listed, with the largest shares coming from oil-fired resources (499 MW) and coal-fired resources (438 MW).

New cleared capacity in FCA 18 accounted for 1,142 MW, or 4%, of cleared capacity and increased by 48% from new, cleared capacity in FCA 17. The largest new entrants were predominantly renewable energy projects consisting of battery storage (741 MW), wind (185 MW), and solar (91 MW).

3.5 Comparison to Other FCAs

Underlying FCA clearing prices and volumes drive trends in FCM payments. Payments for capacity commitment periods (CCPs) 11 through 18 are shown in Figure 3-6 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 14 through 18 are projected payments based on FCA outcomes, as those periods have not yet been settled.[44] The red bar represents Pay-for-Performance (PfP) payments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[45] Payments correspond to the left axis while prices correspond to the right axis. Lastly, the purple bars below the payments represent a capacity surplus (positive) or deficiency (negative) compared to Net ICR.

Figure 3-6: FCM Payments by Commitment Period



The graph shows that a significant capacity surplus led to a steady decline in capacity prices and record-low projected payments for FCA 17 ($0.9 billion). Despite relatively constant surplus amounts in recent auctions, FCA 18 cleared 38% higher than FCA 17 at $3.58/kW-month and projected payments increased accordingly by 37%. An outward shift in the demand curve due to increases in the Net CONE and ICR growth and drove higher clearing prices and projected payments.

[44] Payments for incomplete periods, CCP 13 through CCP 17, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

[45] The Rest-of-Pool capacity zone is made up of all unconstrained import/export capacity zones.

Section 4
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes for Winter 2024, the preceding season (Fall 2023), and the preceding like season (Winter 2023). Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 4-1 below.

Table 4-1: High-level Market Statistics

Market Statistics	Winter 2024	Fall 2023	Winter 2024 vs Fall 2023 (% Change)	Winter 2023	Winter 2024 vs Winter 2023 (% Change)
Real-Time Load (GWh)	30,417	27,577	10%	29,977	1%
Peak Real-Time Load (MW)	18,436	24,054	-23%	19,663	-6%
Average Day-Ahead Hub LMP ($/MWh)	$48.66	$32.03	52%	$78.29	-38%
Average Real-Time Hub LMP ($/MWh)	$44.39	$31.23	42%	$79.52	-44%
Average Natural Gas Price ($/MMBtu)	$4.87	$2.24	117%	$9.15	-47%
Average No. 6 Oil Price ($/MMBtu)	$14.94	$15.81	-6%	$17.05	-12%

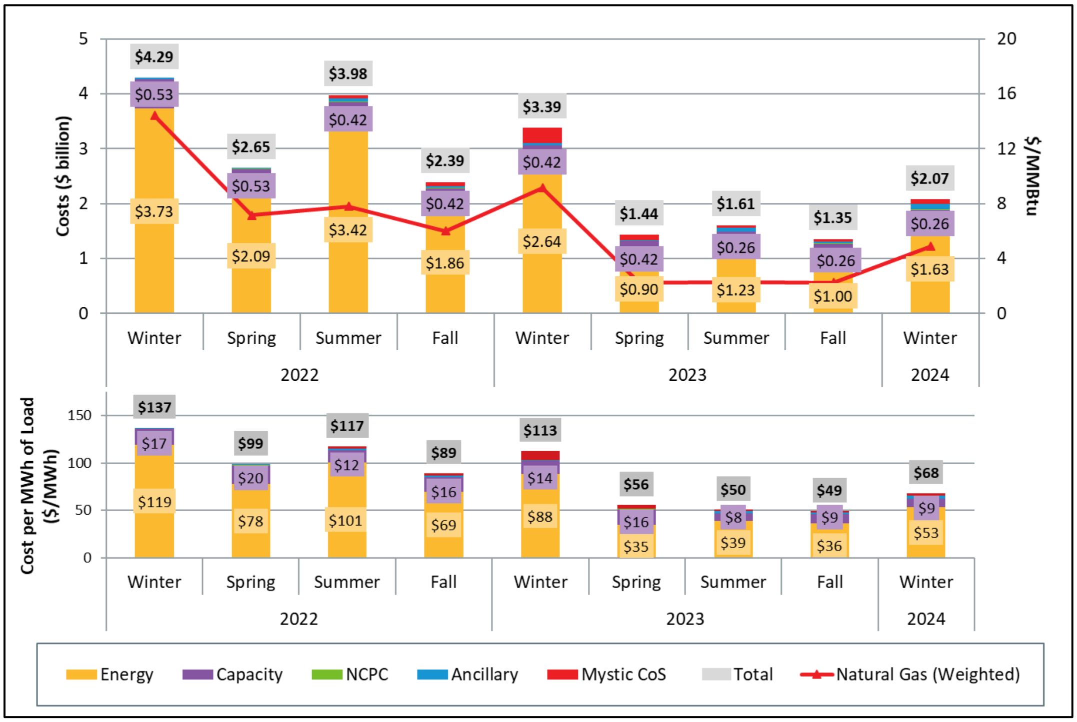
Key observations from the table above:

- Average real-time load increased slightly in Winter 2024 relative to Winter 2023, driven by slightly colder weather during January 2024. Section 0 below discusses load in more detail.
- Average natural gas prices decreased by 47% in Winter 2024 relative to Winter 2023, reflecting the continued easing of prices that were elevated in prior periods as a result of the conflict in Ukraine. Section 2 above discusses the gas market in more detail.
- These lower gas prices were the primary driver of lower day-ahead and real-time LMPs. Winter 2024 had average day-ahead LMPs of $48.66/MWh, 38% lower than in Winter 2024 ($78.29/MWh).
- There was a significant premium in day-ahead prices compared to real-time in Winter 2024; day-ahead prices were $4.27/MWh (10%) higher primarily due to several days that saw larger volumes of real-time solar generation output than forecast, resulting in low midday real-time prices. Other factors also contributed to lower prices during certain hours throughout the quarter, such as additional real-time self-scheduled generation from generators that were returning from outage earlier than expected.
- Load, natural gas prices, and LMPs increased in Winter 2024 relative to *Fall 2023*, consistent with declining temperatures and the associated increase in energy demand.

4.1 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 4-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [46,47]

Figure 4-1: Wholesale Market Costs and Average Natural Gas Prices by Season

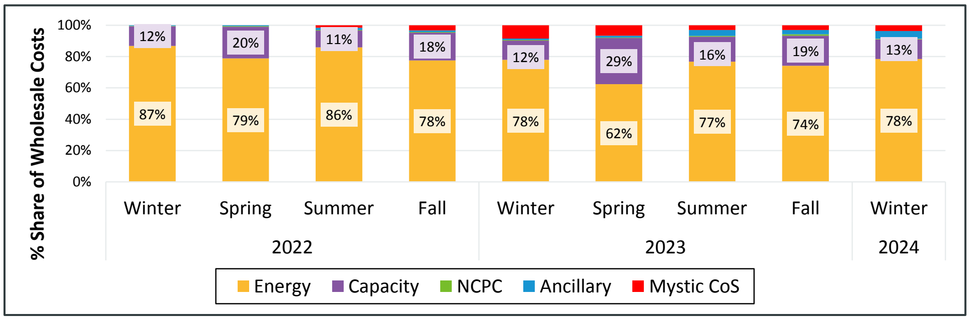


In Winter 2024, the total estimated wholesale cost of electricity was $2.07 billion (or $68/MWh), a decrease of 39% compared to $3.39 billion in Winter 2023, and an increase of 53% over the previous quarter (Fall 2023). Natural gas prices continued to be a key driver of energy prices. The share of each wholesale cost component is shown in Figure 4-2 below.

[46] 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.

[47] 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 4-2: Percentage Share of Wholesale Cost



Energy costs were $1.63 billion ($88/MWh) in Winter 2024, 38% lower than Winter 2023 costs, driven by a 47% decrease in natural gas prices. Energy costs made up 78% of the total wholesale costs.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Winter 2024, the FCA 14 clearing price resulted in capacity payments of $259 million ($9/MWh), representing 13% of total costs. The current capacity commitment period (CCP 14, June 2023 – May 2024) cleared at $2.00/kW-month. This was 47% lower than the primary auction clearing price of $3.80/kW-month for the prior capacity commitment period.

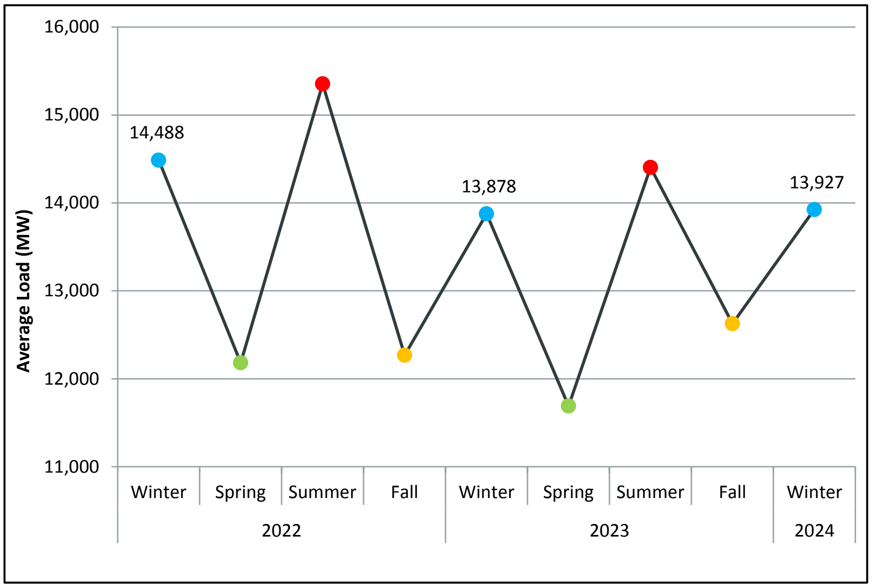
At $9.2 million ($0.30/MWh), Winter 2024 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. Section 5.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves, regulation, and Inventoried Energy Program (IEP) costs, totaled $103 million ($3.37/MWh) in Winter 2024, 5% of total costs. Ancillary service costs increased by $73 million compared to Winter 2023 due to the IEP ($79 million) going into effect in December 2023. Section 2.5 discusses the IEP in detail.

4.2 Load

New England winter loads are driven by heating demand, and are projected to increase significantly through the coming years during a transition to a winter-peaking system.[48] Average seasonal loads through Winter 2024 are shown in Figure 4-3 below.

Figure 4-3: Average Hourly Load



Load averaged 13,927 MW in Winter 2024, up 0.4% from Winter 2023. Winter load in 2023 and 2024 remained low relative to historical averages, with typical winter loads above 14,000 MW in years before 2023. Relatively low loads were driven by mild weather conditions with a total of 2,828 heating degree days (HDDs), similar to Winter 2023 and down 9% from Winter 2022.[49] Minimum daily temperatures never dipped below 10°F, and only one day triggered Inventoried Energy Program (IEP) thresholds while eight days would have occurred in 2022 and three would have occurred in 2023.[50] Winter behind-the-meter photovoltaic output reduced average hourly loads by a record 264 MW, up 30% from 2023 as estimated installed capacity exceeded 2024 forecasts with over 4,000 MW of estimated installed capacity.[51]

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[48] See projections made in the Analysis Group's *Pathways Study, Evaluation of Pathways to a Future Grid* (April 2022), available at https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf.

[49] Heating degree days (HDDs) measure how cold an average daily temperature is relative to 65°F, and indicate 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, that day has five HDDs.

[50] An Inventoried Energy Day is defined as a day during which the average of the high and low temperatures at Bradley International Airport in Windsor Locks, Connecticut is less than or equal to 17°F. See Section 2.5 for a detailed discussion of the Inventoried Energy Program in Winter 2024.

[51] The behind-the-meter installed capacity forecast is 3,996 MW for 2024. Current installed capacity estimates have already exceeded this forecast. See the ISO's 2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) (May 1, 2023), available at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

Load and Temperature

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

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

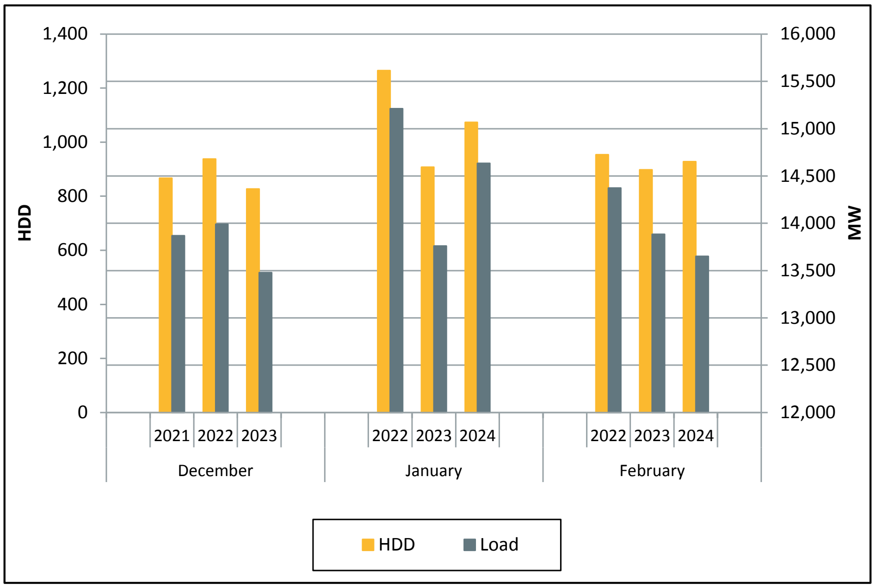
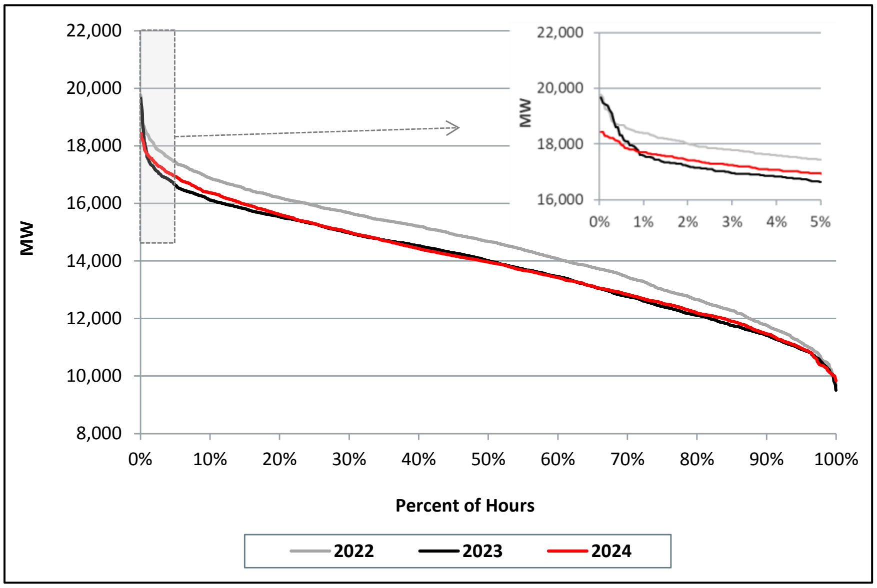


Figure 4-4 shows that Winter 2024 average monthly load peaked in January at 14,635 MW. The coldest weather of the season occurred in January with a total of 1,074 heating degree days, up from 908 in Winter 2023. December load averaged 13,478 MW, down 4% from 2022. Despite similar amounts of heating degree days to the prior two years, February average loads (13,651 MW) fell 2% from 2023 as average behind-the-meter solar generation (264 MW) increased 30% from Winter 2023 following significant installed capacity growth.

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 4-5 below, with the inset graph showing the 5% of hours with the highest loads.

Figure 4-5: Load Duration Curve



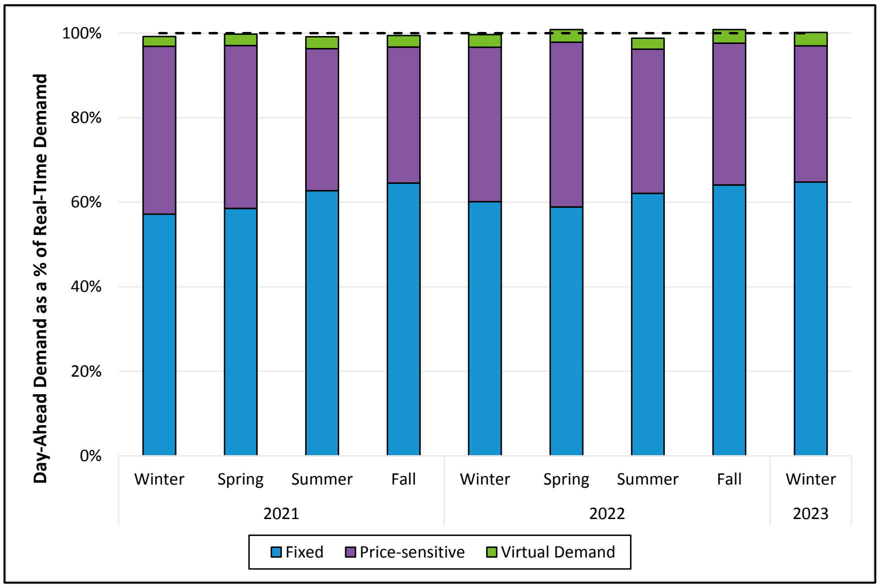
Winter 2024 peak load reached 18,431 MW on January 17, when minimum temperatures fell to 16°F. The absence of extreme cold weather days throughout the winter drove peak loads down 7% from 2023. Peak hours with load above 18,000 MW occurred during the mid-January period of low temperatures and high gas prices, including the Inventoried Energy Day that occurred on January 20.

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 4-6 below.

[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 4-6: Day-Ahead Cleared Demand as a Percent of Real-Time Demand



Participants cleared 101.3% of real-time load in the day-ahead market on average in Winter 2024, up from 100.0% in Winter 2023. Fixed and price-sensitive demand both increased modestly as a share of real-time load, while virtual demand fell to 2.4% of real-time load from 3.1% in Winter 2023. As discussed in Section 5.3, the decline in virtual demand as a share of real-time load in Winter 2024 is associated with decreased clearing at the hub and load zones. Participants continued to bid price-sensitive demand well above expected LMPs, and most price-sensitive demand was therefore functionally similar to fixed demand.

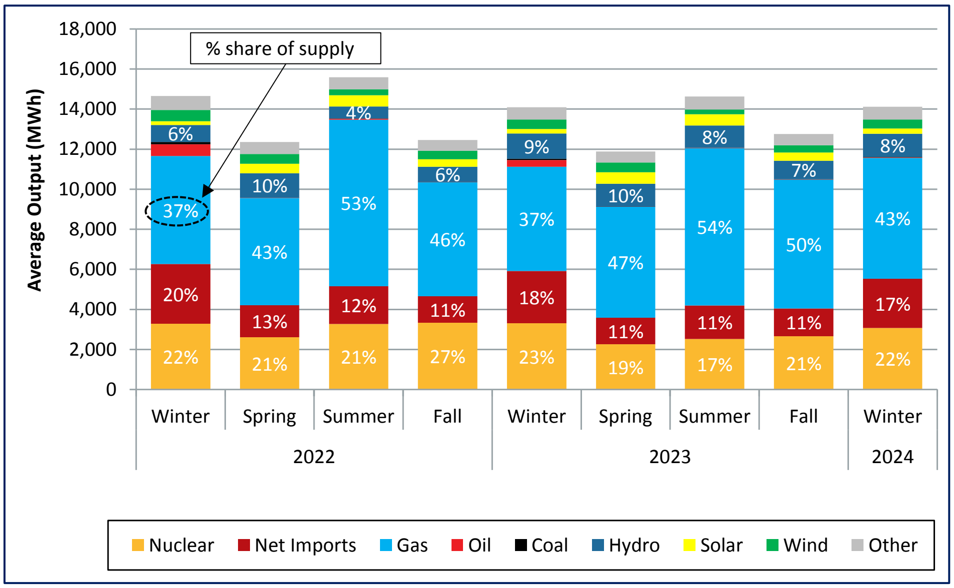
4.3 Supply

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

4.3.1 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 2022 through Winter 2024 are illustrated in Figure 4-7 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 4-7: Share of Electricity Generation by Fuel Type



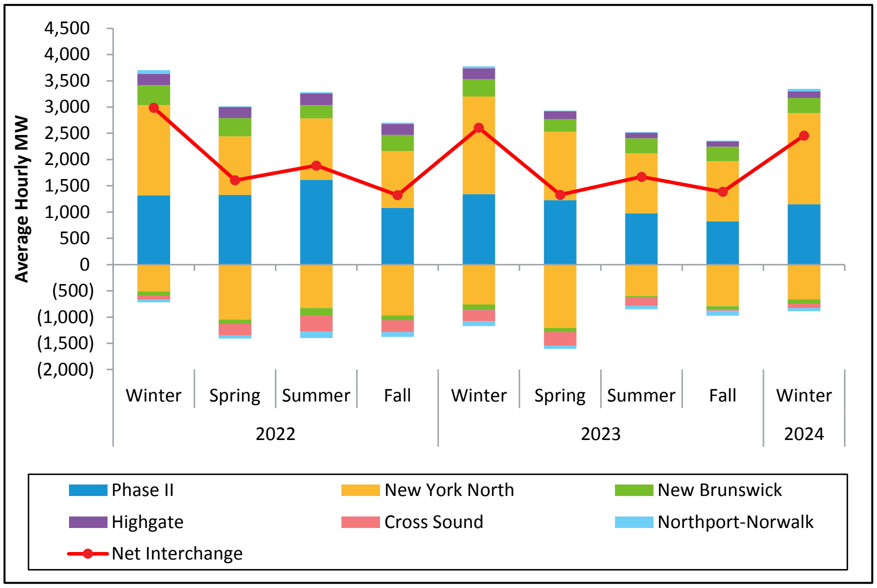
Average output in Winter 2024 (14,121 MWh) was on par with that of Winter 2023. The most notable change from the prior winter season is an 823 MWh increase in average output from natural gas-fired generation. This is a result of natural gas being in-merit for energy throughout this relatively mild winter season, and the subsequent reduction in the dispatch of oil-fired generation relative to prior winters. Oil-fired generation provided only 28 MWh of energy on average in Winter 2024, a decrease of 92% from the Winter 2023. Another contributor to the increase in energy from natural gas-fired resources is a slight decrease in supply from net imports, as discussed in the next section. The majority of New England's energy continued to be provided by nuclear generation, gas-fired generation, and net imports. Together, these categories accounted for 82% of total energy production in Winter 2024.

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

4.3.2 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 2024.[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 4-8 below.

Figure 4-8: Average Hourly Real-Time Imports, Exports and Net Interchange



On average, the net flow of energy into New England was 2,459 MW per hour in Winter 2024, up 77% from Fall 2023. Hourly net interchange tends to increase from fall to winter. The colder winter temperatures leads 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. In Winter 2024, lower energy prices relative to Winter 2023 contributed to a 6% decrease in net interchange year over year. Additional supply-side factors, elaborated on in more detail below, resulted in a notable decrease in imports from Canada. Total net interchange in Winter 2024 represented 18% of load (NEL), which was slightly less than in Winter 2023 (19%).

Canadian Interfaces

In Winter 2024, net imports from the Canadian interfaces averaged 1,479 MW per hour, which was a 16% decrease compared to Winter 2023. The majority of the reduction in Canadian net imports occurred at the Phase II interface that connects New England with Québec. In Québec, abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, in the past year, sparse snow cover, a low spring run-off and

[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.

less summer precipitation contributed to lower reservoir levels in Québec and fewer opportunities to export power into New England.[55] At Phase II, net imports averaged 1,148 MW per hour, which was 14% lower than in Winter 2023.

Highgate, the other interface that connects New England to Québec, also saw a decrease in net imports. In Winter 2024, net imports averaged 123 MW per hour at Highgate, which was down from 203 MW per hour in Winter 2023.

New York Interfaces

In Winter 2024, New England imported an average of 980 MW per hour across the three New York interfaces, a 16% increase compared to the prior winter. The increase in net interchange was mostly driven by reduced export bids across the Cross Sound Cable interface. This winter, net exports at Cross Sound Cable averaged 85 MW per hour, down 60% from Winter 2023. Exports to New York fell at the interface due to reduced export bids by one participant. At New York North, average net imports fell by 33 MW per hour while average net exports at Northport-Norwalk fell by 41 MW per hour year-over-year.

[55] 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 5
Day-Ahead and Real-Time Markets

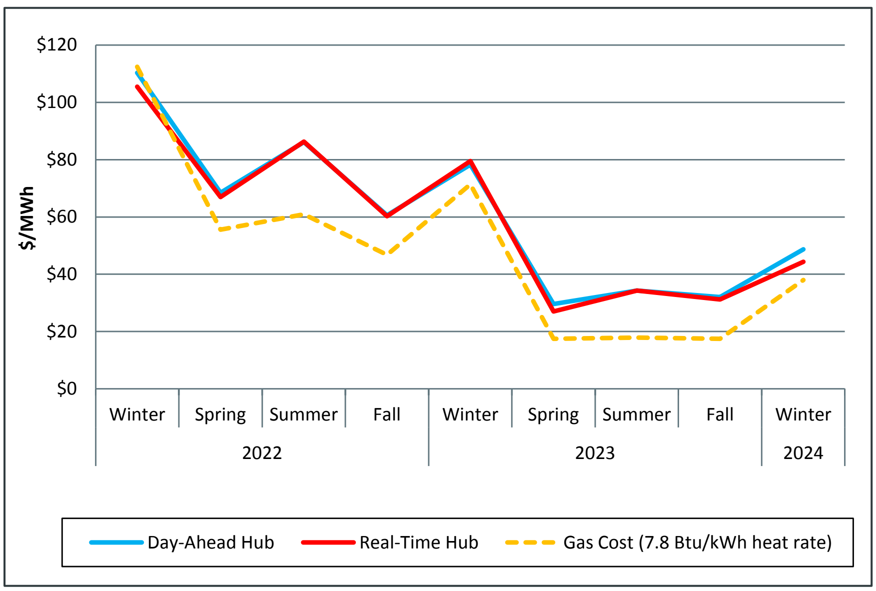
This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

5.1 Energy Prices

The average real-time Hub price for Winter 2024 was $44.39/MWh, 9% lower than the average day-ahead price of $48.66/MWh. Compared to Winter 2023, average real-time and day-ahead Hub prices decreased by 44% and 38%, respectively, driven by a 47% decrease in average natural gas prices.

Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 5-1 below. The natural gas cost is based on the seasonal average natural gas price and a generator heat rate of 7,800 Btu/kWh.[56]

Figure 5-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 5-1 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.

Average real-time prices in Winter 2024 ($44.39/MWh) were lower than average day-ahead prices ($48.66/MWh) primarily due to several days that saw large volumes of real-time solar generation output, resulting in low midday real-time prices. In many of these instances, actual solar output was greater than forecasted. To a lesser extent, other factors also contributed to lower prices during

[56] The average heat rate of combined cycle gas turbines in New England is estimated to be 7,800 Btu/kWh.

certain hours throughout the quarter, such as additional real-time self-scheduled generation from generators that were returning from outage earlier than expected.

Gas costs averaged $37.95/MWh in Winter 2024. Average electricity prices were about $11/MWh higher than average estimated Winter 2024 gas costs in the day-ahead market, a higher spread compared to that of Winter 2023 ($7/MWh). In Winter 2024, supply mix changes relative to the previous winter partially muted the impact of lower natural gas prices on LMPs. Total generator outages increased by 614 MW in Winter 2024 compared to Winter 2023. Nuclear generation was down by 242 MW on average per hour due to unplanned outages in December and January. Additionally, the system Total-30 reserve margin decreased by 430 MW in Winter 2024 compared to the previous winter, primarily due to a 467 MW increase in pumped-storage generator outages. These outages increased the likelihood of tight system conditions and resulted in more expensive generator commitments. Additionally, net imports fell by 148 MW in Winter 2024 compared to Winter 2023.

Prices did not differ significantly among the load zones in either market in Winter 2024, indicating that there was relatively little transmission congestion on the system at the zonal level.

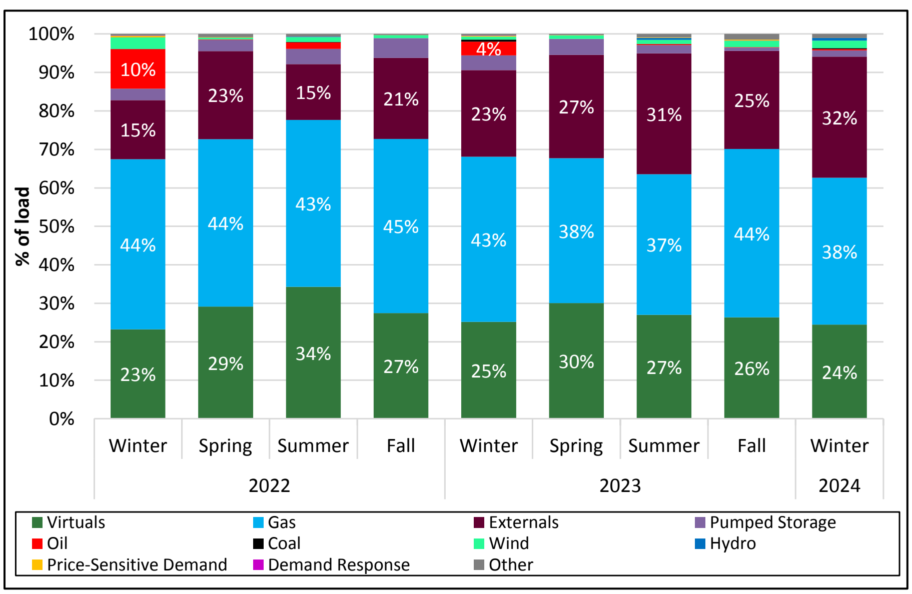
5.2 Marginal Resources and Transactions

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 constrained and marginal resources generally 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 2022 is illustrated in Figure 5-2 below.

Figure 5-2: Day-Ahead Marginal Units by Transaction and Fuel Type

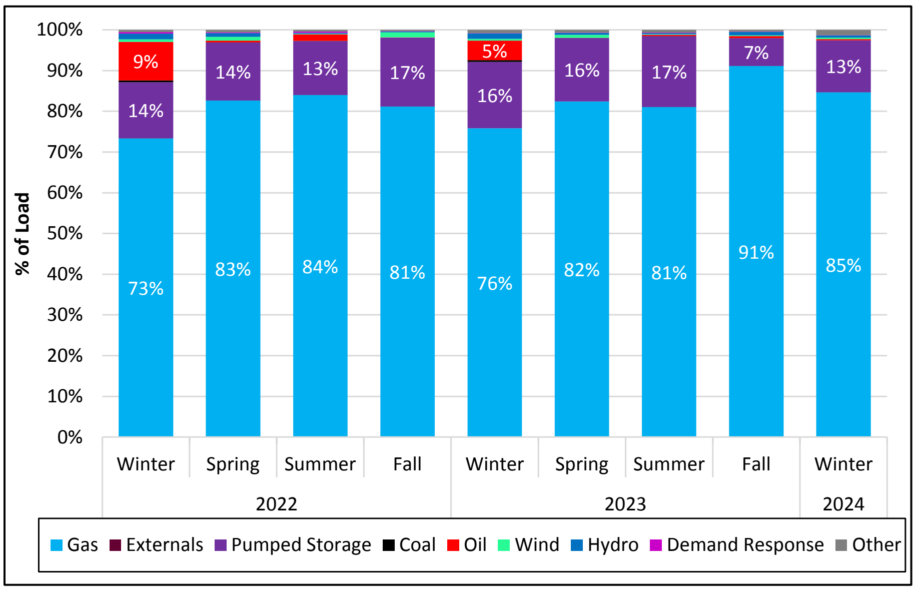


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 38% of total day-ahead load in Winter 2024. Virtual transactions and external transactions set price for 56% of load, a slight increase from their sum in Fall 2023 (52%). Notably, oil-fired generation was rarely marginal in Winter 2024, and set day-ahead LMPs for less than 1% of load in this season. This is a marked decrease from the prior two winter seasons, which had colder weather and more frequent instances of oil being in merit for energy.

Real-time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2022 is shown in Figure 5-3 below.[57]

Figure 5-3: Real-Time Marginal Units by Fuel Type



Similar to the day-ahead market, natural gas-fired generators set price for highest percentage of load in the real-time market in Winter 2024 (85%). Pumped-storage facilities (generation and demand) set price for 13% of load in Winter 2024, a level that was in-line with others over the reporting period. Oil-fired generation set price very infrequently in the real-time market in Winter 2024 relative to prior winter seasons, in line with the milder winter conditions.

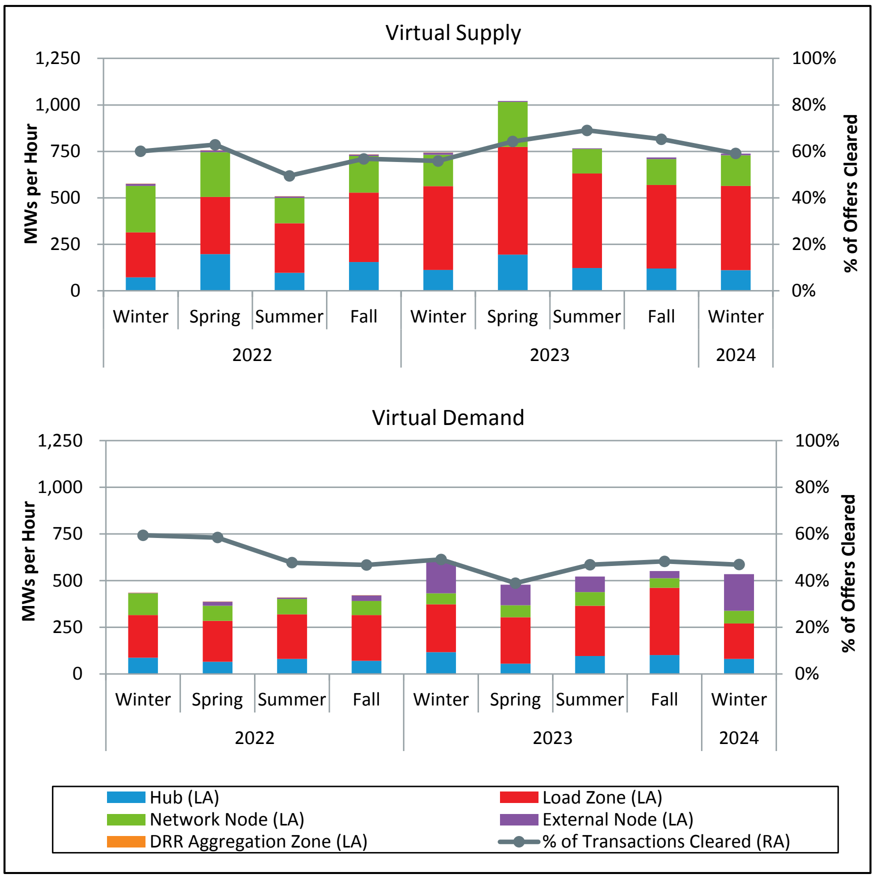
[57] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, solar, and battery storage.

5.3 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 5-4 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 5-4: Cleared Virtual Transactions by Location Type



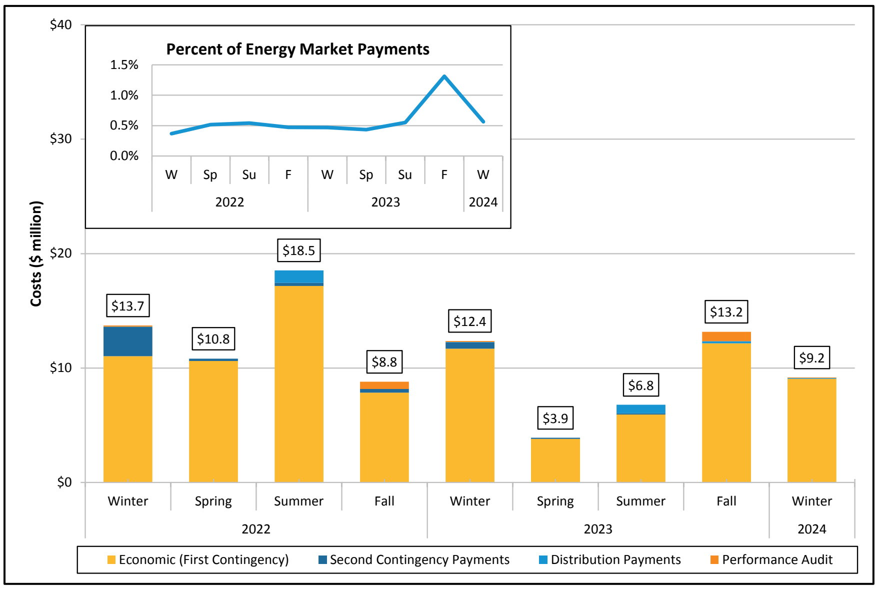
Total cleared virtual supply averaged 738 MW per hour in Winter 2024, down 1% from Winter 2023 (743 MW per hour). Generally, virtual supply activity is greater than virtual demand activity for two reasons: 1) the growing amount of solar settlement-only generation (SOG) and 2) the day-ahead bidding behavior of wind generation. By the end of Winter 2024, the installed capacity of solar SOGs was nearly 2,200 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 generation. Typically, wind generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[58]

Cleared virtual demand averaged 534 MW per hour in Winter 2024, down 11% from Winter 2023 (600 MW per hour). The year-over-year decrease was mostly due to lower volumes of cleared virtual demand at the Hub and load zones, which decreased collectively by 102 MW per hour. Two participants accounted for a majority of the decrease (77 MW per hour) at the Hub and load zones.

5.4 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.[59] Figure 5-5 below shows total NCPC by category and season for 2022-2024. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

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



NCPC payments totaled $9.2 million in Winter 2024, comprising 0.6% of energy market payments. Uplift as a share of energy market payments fell significantly in Winter 2024 as pumped-storage generators returned from outage and dependence on oil-fired fast start generators declined.[60] Total NCPC payments fell 26% from Winter 2023 as economic uplift

[58] In Winter 2024, wind generation averaged 171 MW per hour in the day-ahead market, while real-time wind generation averaged 455 MW hour.

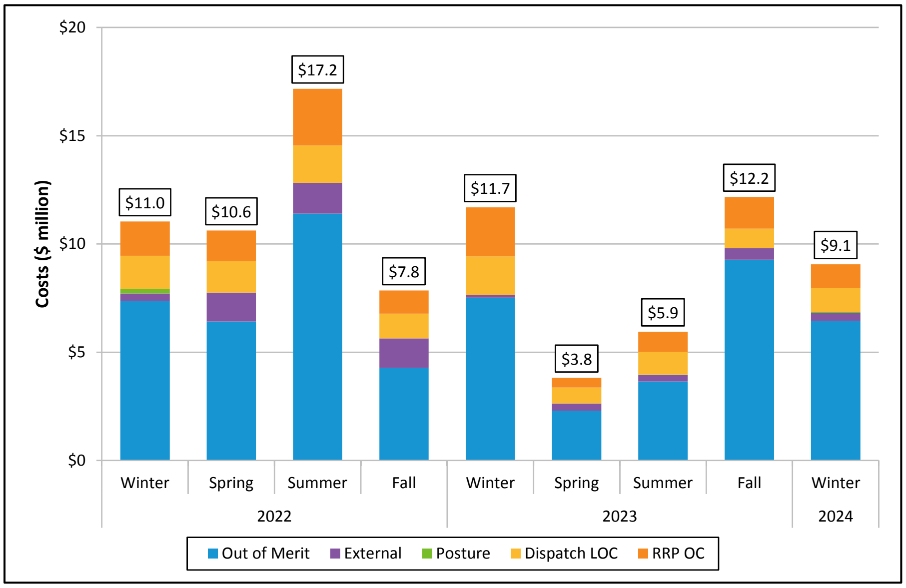
[59] NCPC payments include economic/first contingency NCPC payments, local second -contingency NCPC payments (reliability costs paid to generators providing capacity in constrained areas), voltage reliability NCPC payments (reliability costs paid to generators dispatched by the ISO to provide reactive 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).

[60] For a detailed analysis of elevated NCPC payments in Fall 2023, see our *Fall 2023 Quarterly Markets Report* (January 29, 2024), pp. 25-26, available at https://www.iso-ne.com/static-assets/documents/100007/2023-fall-quarterly-markets-report.pdf

payments fell. The vast majority (99%) of uplift was economic payments to generators committed to meet load and reserve requirements. There was no uplift for second contingency commitments throughout Winter 2024, and both distribution payments and performance auditing uplift made up the remainder of 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 5-6 below shows economic payments by sub-category.

Figure 5-6: Seasonal Economic Uplift by Sub-Category



Out of merit payments totaled $6.4 million in Winter 2024, accounting for 71% of all economic uplift. Out of merit payments fell 31% from Fall 2023 and 14% from Winter 2023. The significant decline in out of merit payments from Fall 2023 was largely driven by the return of several fast-start pumped-storage generators from outages in the Fall and an associated decline in out of merit payments to fast-start oil-fired generation.[61] Opportunity cost payments, including both dispatch and rapid-response pricing opportunity costs, totaled $2.2 million, down 46% from Winter 2023 following a 44% decline in average real-time LMPs. Economic uplift to external transactions totaled $0.4 million. While posturing payments remained a small portion of total economic payments, posturing uplift increased from Fall 2023, driven by postured pumped-storage generators on December 3.[62]

[61] For a detailed discussion of elevated out of merit NCPC in Fall 2023, see our *Fall 2023 Quarterly Markets Report* (January 29, 2024), pp. 25-26, available at https://www.iso-ne.com/static-assets/documents/100007/2023-fall-quarterly-markets-report.pdf

[62] The pumped-storage generators were postured on December 3 due to tight reserve margins, and received $60 thousand in posturing NCPC credits.

5.5 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.[63] 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 5-1 below.[64]

Table 5-1: Hours and Level of Non-Zero Reserve Pricing

Product	Winter 2024		Winter 2023		Winter 2022	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$18.14	140	$31.13	169.1	$16.24	223.8
TMNSR	$72.43	11.1	$682.89	4.3	$0.00	.
TMOR	$78.29	5.8	$490.95	3.7	$0.00	.

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 140 hours during Winter 2024. This is the lowest incidence of non-zero TMSR pricing in the reporting period, and reflects 29 fewer hours than in Winter 2023 and 84 fewer hours than in Winter 2022. The decline in the most recent two winter seasons is attributable to a reduction in the TMSR requirement, relative to the requirement in effect in Winter 2022.[65]

TMNSR and TMOR prices were non-zero more frequently than in prior winter seasons, indicative of an increase in the need to re-dispatch the system to maintain total 10- and 30-minute reserve requirements. However, average reserve prices during these periods remained relatively low, particularly compared to Winter 2023, when reserve shortages resulted in capacity scarcity conditions on December 24, 2023.

Real-time Reserve Payments

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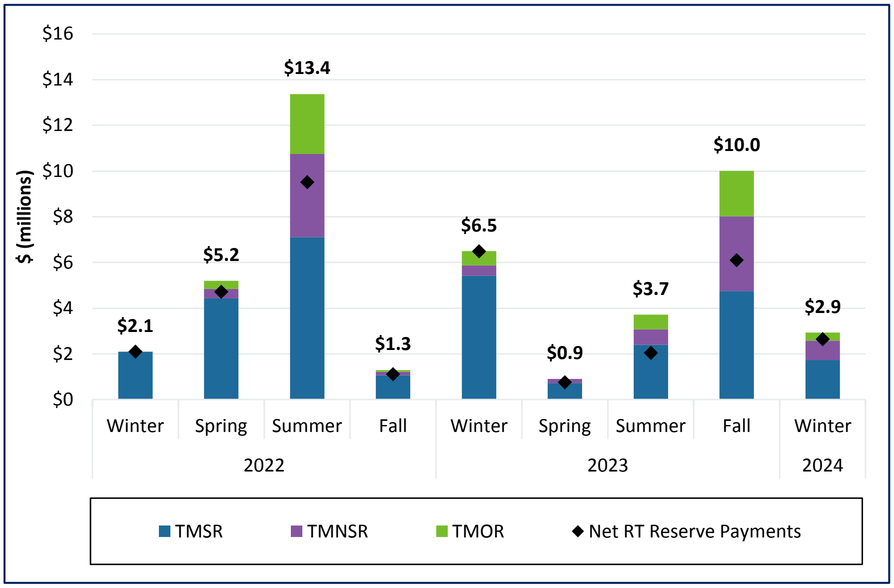
[63] Real-time operating reserve requirements are utilized to maintain system reliability. There are several real-time operating reserve requirements: (1) the ten-minute reserve requirement; (2) the ten-minute spinning reserve requirement; (3) the minimum total reserve requirement; (4) the total reserve 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.

[64] 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.

[65] This change reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022. The operational decision to change this percentage stemmed from changes to the reserve designation rules for composite resources, which provide more accurate accounting of TMSR supplied by those resources. Composite resources those that are modeled as a single generator in the ISO's network model, but that exist in reality as multiple distinct units (such as a series of several hydroelectric dams).

Real-time reserve payments by product and by zone are illustrated in Figure 5-7 below.[66] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Market (FRM) resources providing real-time reserves).[67]

Figure 5-7: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Winter 2024 ($2.9 million) were down considerably from Winter 2023 ($6.5 million), as no reserve shortages occurred during Winter 2024. Gross reserve payments were much lower than the recent Fall 2023 season ($10 million), 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. Of the total reserve payments made in Winter 2024, the majority went to resources providing TMSR (59%), while smaller portions went to resources providing TMNSR (29%) or TMOR (12%).

Net real-time reserve payments in Winter 2024 ($2.6 million) were only slightly reduced from their gross levels.

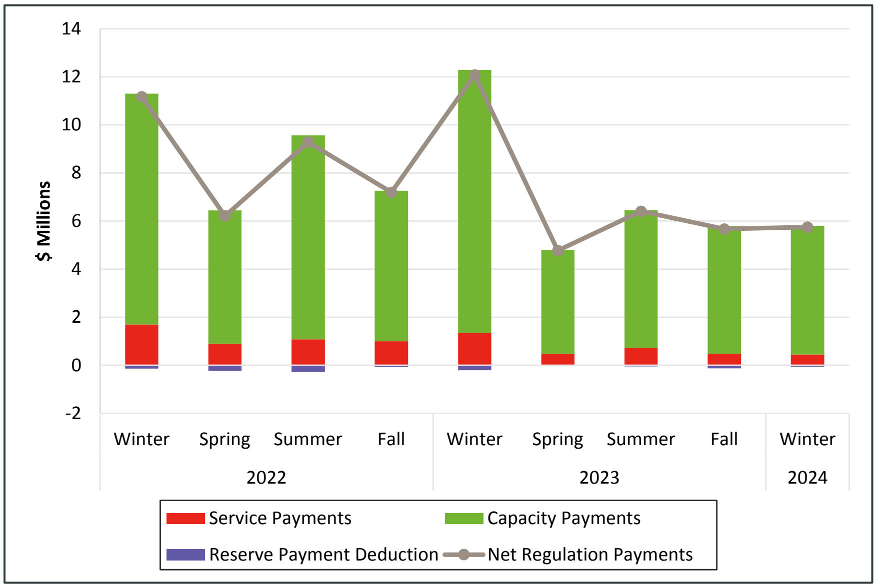
[66] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

[67] 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.

5.6 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 5-8 below.

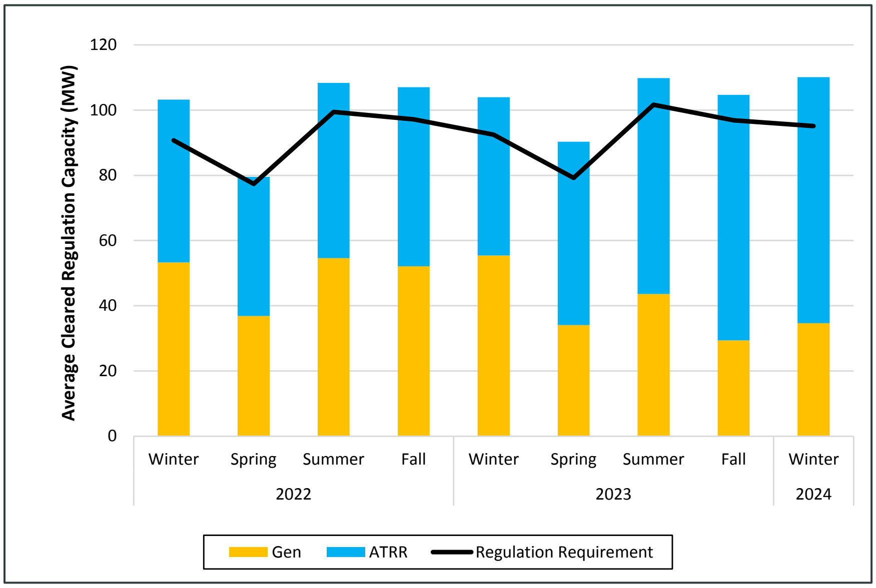
Figure 5-8: Regulation Payments



Total regulation market payments were $5.7 million during Winter 2024, down 52% from $12.1 million in Winter 2023 but nearly identical to Fall 2023 payments. The decrease in payments compared to Winter 2023 resulted primarily from lower capacity prices (down 53%). Capacity prices decreased due to lower energy market opportunity costs, reflecting a decline in energy market LMPs compared to the earlier period. Regulation service prices also decreased (down 68%) from Winter 2023.

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 5-9 below.

Figure 5-9: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed over the reporting period. In Winter 2022, ATRRs (blue shading) cleared an average of 50 MW of regulation capacity, making up 48% of total cleared regulation. In Winter 2024, ATRRs provided 74 MW or 69% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 209 MW on average in Winter 2024, up from 110 MW in Winter 2022. The change in resource mix also suggests that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

Section 6
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 6.1, we evaluate energy market competitiveness by quarter using two structural market power metrics at the system level. In section 6.2, 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.

6.1 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).[68]

When a participant's available supply exceeds the supply margin[69], they are considered pivotal.[70] 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 6-1 below.

Table 6-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
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%

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

[68] 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.

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

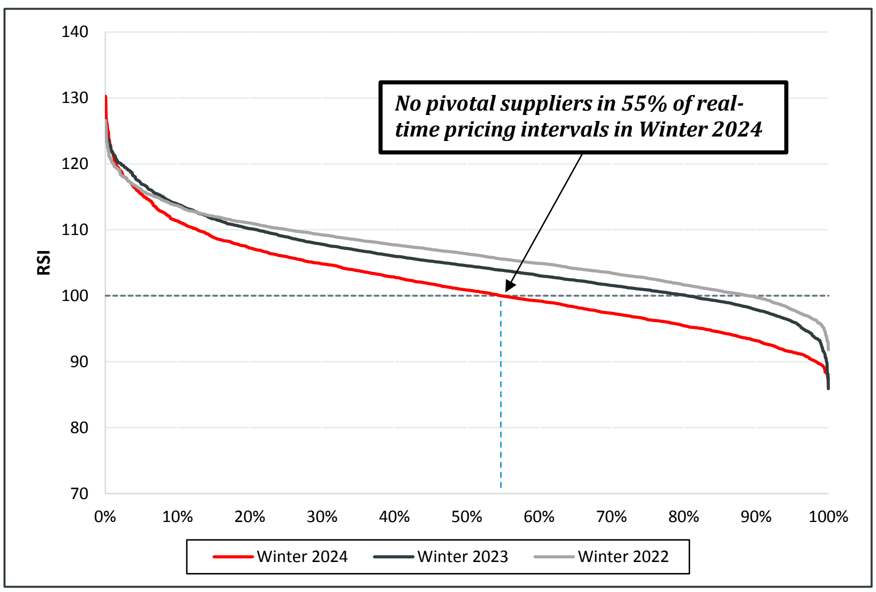
[70] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

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 45% of real-time pricing intervals in Winter 2024, which was higher than that of the previous two winters (20% and 12%), but lower than that of Fall 2023 (60%). The year-over-year increase was due to lower total 30-minute reserve margins, which decreased by an average of 430 and 655 MW compared to Winter 2023 and Winter 2022, respectively. When reserve margins are lower, it is more likely that the largest supplier is needed to meet load and the reserve requirement. The lower reserve margins primarily resulted from the aforementioned pumped-storage generator outages that began during early Fall 2023 and extended into Winter 2024. Most of these outages ended in late December 2023, which explains why they had a larger impact on the reserve margin and pivotal supplier frequency in Fall 2023 than in Winter 2024.

Duration curves that rank the average hourly RSI over each fall quarter in descending order are illustrated in Figure 6-1 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 6-1: System-Wide Residual Supply Index Duration Curves



In Winter 2024, the RSI was lower than in the previous two winters across most ranked observations due to the lower reserve margins discussed above. The lowest hourly RSI value of Winter 2024 was 87.4, which occurred during the evening peak on January 8 due to tight conditions caused by an unplanned nuclear generator outage.

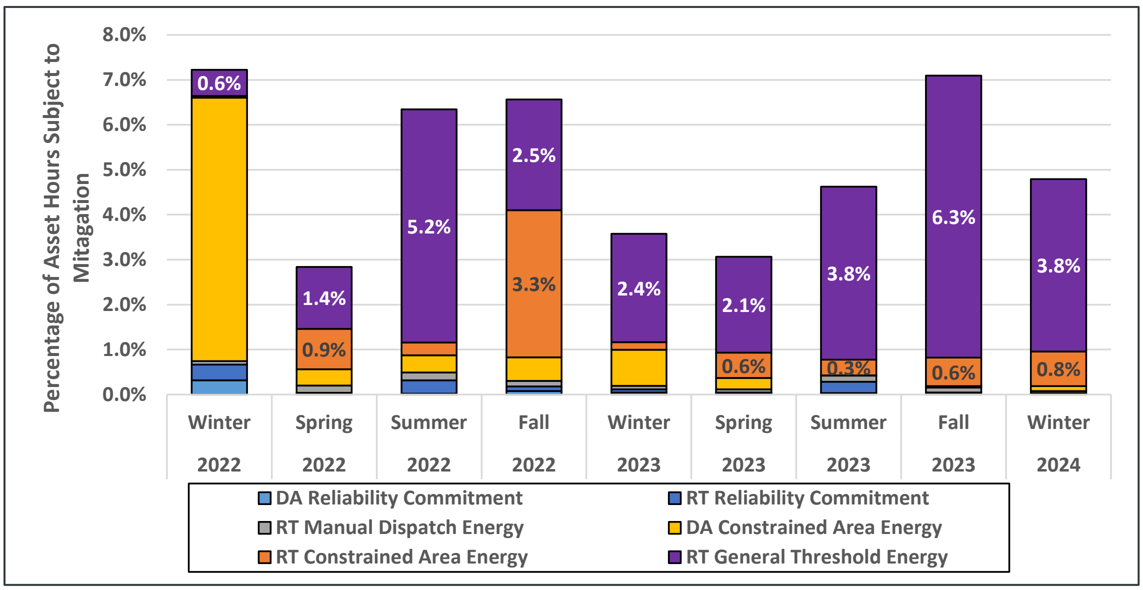
6.2 Energy Market Supply Offer Mitigation

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 2024.

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 2022 to Winter 2024 is shown below in Figure 6-2.[71]

Figure 6-2: Energy Market Mitigation Structural Test Failures



In Winter 2024, the total asset hours subject to mitigation reached 412 thousand asset hours, in which approximately 20,000 asset hours (4.8%) failed structural tests.[72] 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 6-3 along with the total amount of asset hours subject to mitigation (white boxes).

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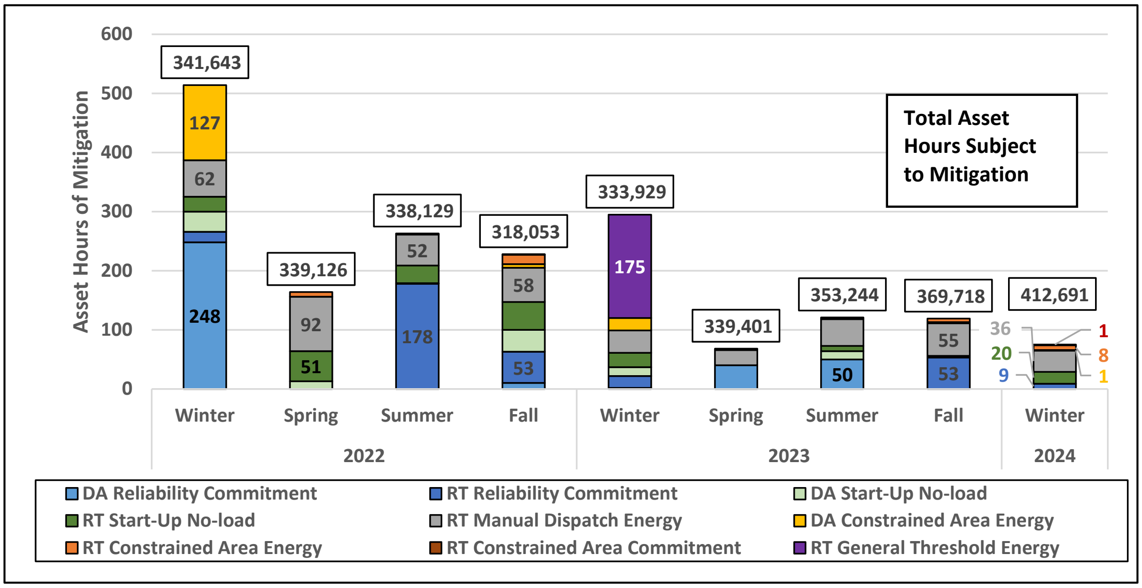
[71] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available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

[72] 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 6-3: Energy Market Mitigation Asset Hours



Total mitigation asset hours significantly decreased from 295 hours in Winter 2023 to 75 hours in Winter 2024. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Winter 2024 with 36 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing manual dispatch offers to be 10% higher than reference levels.[73]

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.[74] In Winter 2024, reliability commitments reached 124 asset hours and occurred solely in the real-time energy market. The majority of asset hours (110 asset hours) occurred in the Southeastern Massachusetts load zone. Reliability commitment mitigations occurred for only nine asset hours in Winter 2024.

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.[75] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In Winter 2024, only two participants were associated with the 20 asset hours of SUNL commitment mitigation.

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[73] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets: A Market Primer (June 5, 2023)*, Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

[74] 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.

[75] 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).

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. In Winter 2024, structural test failures totaled 3,638 asset hours, in which transmission constraints in Connecticut accounted for nearly 70% of all structural test failures at 2,524 asset hours. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. Over the three-year reporting period, mitigation has occurred for only 161 asset hours in the day-ahead energy market and only 43 asset hours occurred in the real-time energy market.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs the least frequency of all mitigation types. Across the reporting period, an average of roughly 10,000 asset hours of pivotal supplier energy were subject to mitigation each quarter; mitigation has occurred for only 175 asset hours, all in Winter 2023. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with five participants accounting for 85% of the structural test failures over the review period.

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 92% of the 197 asset hours of manual dispatch in Winter 2024. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than any other mitigation type, reaching a total of 36 asset hours in Winter 2024.

Section 7
Forward Markets

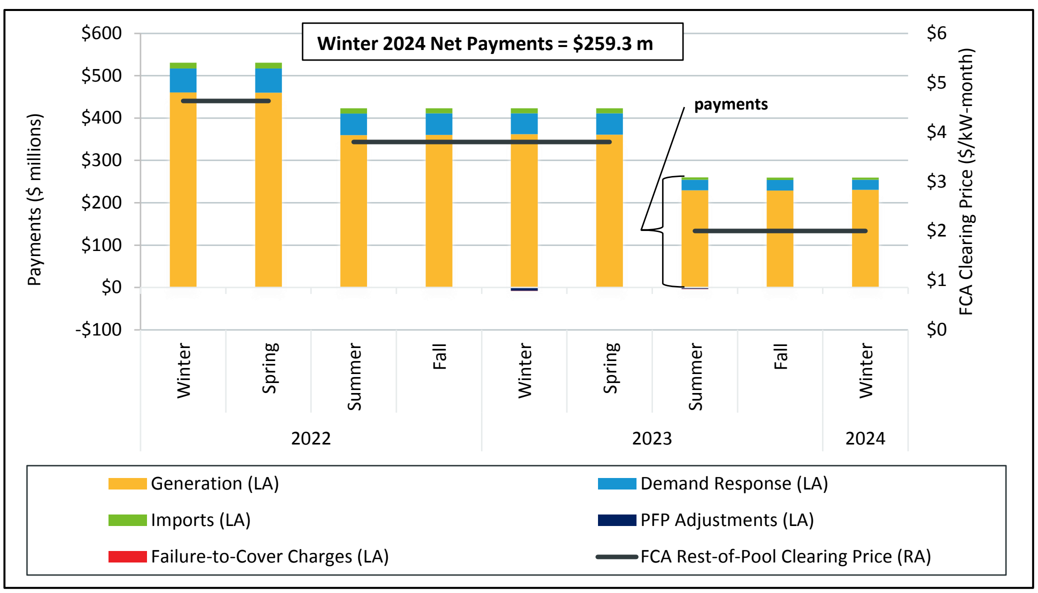
This section covers activity in the Forward Capacity Market (FCM), and in Financial Transmissions Rights (FTRs). The recently-conducted Forward Capacity Auction for the eighteenth capacity commitment period (2025/26) is covered in Section 3 of the report.

7.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Winter 2024 started on June 1, 2023 and will end on May 31, 2024. The corresponding Forward Capacity Auction (FCA 14) resulted in a lower clearing price than the previous auction and obtained sufficient resources needed to meet forecasted demand. The auction procured 33,956 megawatts (MW) of capacity, which exceeded the 32,490 MW Net Installed Capacity Requirement (Net ICR). Mystic 8 and 9 (~1,400 MW total) remained in FCA 14 due to a cost-of-service agreement with the ISO for winter fuel security. The auction cleared at a price of $2.00/kW-month, 47% lower than the previous year's $3.80/kW-month. The $2.00/kW-month clearing price was applied to all capacity zones and interfaces within New England. The results of FCA 14 led to an estimated annual cost of $0.9 billion in capacity payments, $0.7 billion lower than capacity payments incurred in FCA 13.

Total FCM payments, as well as the clearing prices for Winter 2022 through Winter 2024, are shown in Figure 7-1 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 adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 7-1: Capacity Market Payments



In Winter 2024, capacity payments totaled $259.3 million. Total payments were down 38% from Winter 2023 ($415.7 million), driven by an 47% decrease in the clearing price from FCA 13 ($3.80/kW-month) to FCA 14 ($2.00/kW-month). Failure-to-Cover (FTC) charges, or negative adjustments to the FCM credit which is applied when a resource has not demonstrated the ability to cover its CSO, totaled approximately $191 thousand in Winter 2024.

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 2024 alongside the results of the relevant primary FCA are detailed in Table 7-1 below.

Table 7-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

				Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW**	Maine	Northern New England	Southeastern New England
FCA 14 (2023 - 2024)	Primary	12-month	2.00	33,956			
	Monthly Reconfiguration	Feb-24	3.01	1,057			
	Monthly Bilateral	Feb-24	4.50	6			
	Monthly Reconfiguration	Mar-24	2.50	958			
	Monthly Bilateral	Mar-24	1.19	1			
	Monthly Reconfiguration	Apr-24	1.00	679			
	Monthly Bilateral	Apr-24	1.66	3			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions (MRAs) took place in Winter 2024: the February 2024 auction in December, the March 2024 auction in January, and the April 2024 auction in February. Clearing prices in the February and March auctions were driven higher than the FCA clearing price due to higher demand-side participation and increased clearing volumes. Clearing prices in the April auction fell below the FCA clearing price, aligned with a proportionate decrease in cleared volumes.

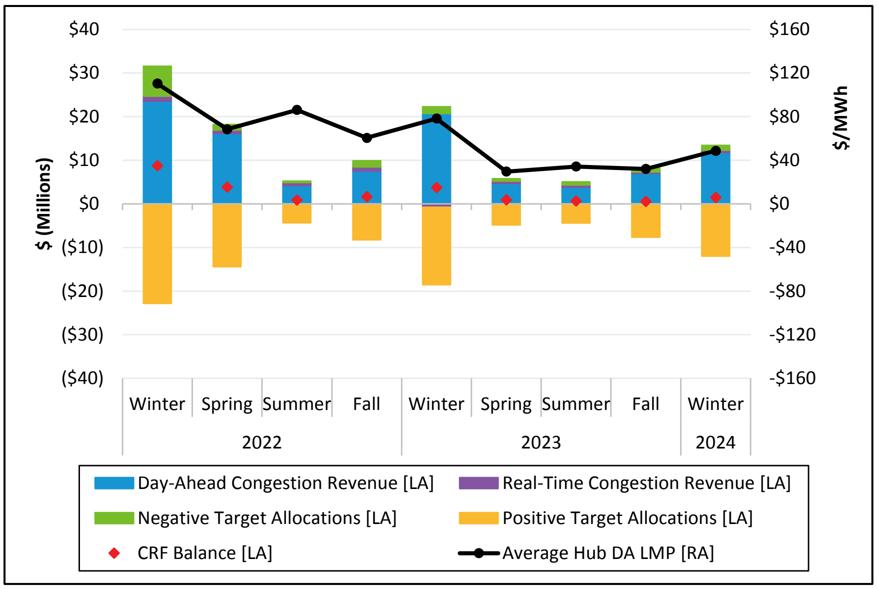
7.2 Financial Transmission Rights

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 7-2 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.[76,77] This figure also depicts the quarterly average day-ahead Hub LMP.[78]

Figure 7-2: Congestion Revenue and Target Allocations by Quarter



Most congestion-related totals in Winter 2024 moved in line with the day-ahead energy price. Day-ahead congestion revenue amounted to $11.8 million in Winter 2024. This represents a 69%

[76] The CRF balances depicted in Figure 7-2 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).

[77] Figure 7-2 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.

[78] All else equal, congestion revenue and target allocations tend to be higher when energy prices are higher. To see this, we can consider an example of an export-constrained area where the marginal resource is setting the area's LMP at $0/MWh. If the marginal resource outside the export-constrained area is setting that area's price at $35/MWh, then the marginal value of the binding constraint (which is used to determine congestion revenue and target allocations) would be -$35/MWh. If the marginal resource outside of the export-constrained area were setting the price at $70/MWh (instead of $35/MWh), the marginal value of the binding constraint, the congestion revenue and the target allocation values would increase in a corresponding fashion.

increase relative to Fall 2023 ($7.0 million) and a 43% decrease relative to Winter 2023 ($20.7 million). Positive target allocations in Winter 2024 ($12.0 million) followed a similar pattern, increasing by 56% relative to Fall 2023 ($7.7 million) and decreasing by 32% relative to Winter 2023 ($17.7 million). Negative target allocations in Winter 2024 ($1.1 million) increased by 28% from their Fall 2023 level ($0.9 million) and decreased by 26% from their Winter 2023 level ($1.5 million). Meanwhile, real-time congestion revenue in Winter 2024 ($0.5 million) remained relatively modest and was generally in line with recent historical levels.

FTRs were fully funded in December 2023, January 2024, and February 2024.[79,80] At the end of 2023, the congestion revenue fund had a surplus of $6.0 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 2023, $0.6 million went to positive target allocations that had been underfunded during the year.[81] The remaining $5.4 million was then allocated to entities that had paid congestion costs during the year. At the end of February 2024, the congestion revenue fund had a surplus of $1.2 million.

[79] 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.

[80] For more information about the monthly FTR settlement, see the *2023 and 2024 FTR Monthly Summaries*, available at https://www.iso-ne.com/static-assets/documents/2023/02/2023_ftr_monthly_summary.pdf and https://www.iso-ne.com/static-assets/documents/100008/2024-monthly-summary.pdf.

[81] FTRs were not fully funded in October 2023, when 79.5% of positive target allocations were funded.

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.[82] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[83]

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

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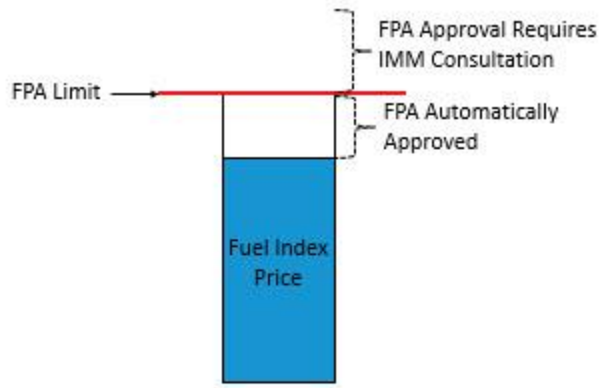
[82] See *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.7.5, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

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

[84] 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).