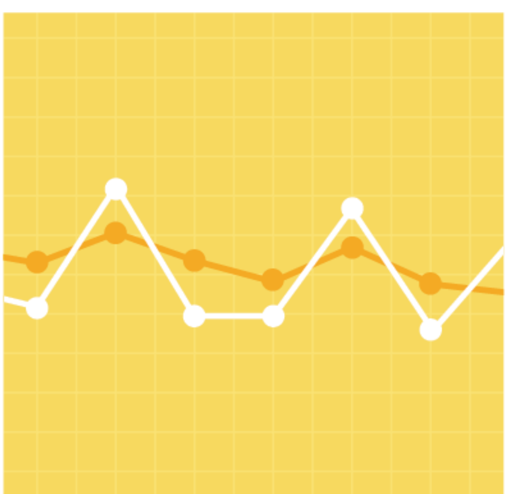
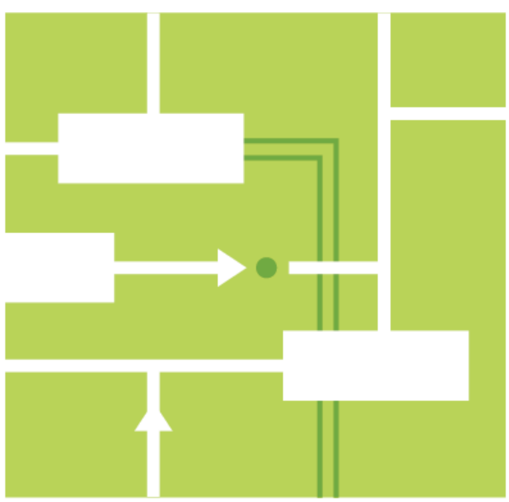
Spring 2023
Quarterly Markets Report

By ISO New England's Internal Market Monitor

AUGUST 1, 2023





Preface/Disclaimer

The Internal Market Monitor (“IMM”) of ISO New England Inc. (the “ISO”) publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2023 (March 1, 2023 through May 31, 2023).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.40 billion, down 49% from $2.65 billion in Spring 2022. The decrease was driven by lower energy costs.

Energy costs totaled $0.90 billion; down 57% (or $1.19 billion) from Spring 2022 costs. Decreased energy costs were a result of lower natural gas prices. In Spring 2023, gas prices decreased by 69% compared to Spring 2022.

Capacity costs totaled $423 million, down 21% (by $110 million) from last spring. Beginning in Summer 2022, lower capacity clearing prices from the thirteenth Forward Capacity Auction (FCA 13) contributed to lower wholesale costs relative to the previous FCA. In FCA 13, a large influx of lower-priced, new capacity displaced higher-priced existing capacity. During Spring 2022, the capacity payment rate for all new and existing resources was $4.63/kW-month. This year, the payment rate for new and existing resources was lower, at $3.80/kW-month.

In Summer 2022, the Mystic 8 and 9 generators began receiving supplemental payments to offset operating costs per their cost-of-service agreement (Mystic CoS) with the ISO.[3] These payments totaled $59.8 million in Spring 2023. Mystic 8 and 9 will receive supplemental payments until May 2024.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $29.62 and $27.04 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 57-60% lower than Spring 2022 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $2.24/MMBtu in Spring 2023, 69% lower than the Spring 2023 price of $7.14/MMBtu. This decrease continued the trend of lower gas prices in Winter 2023, and also reflected record U.S. natural gas production in April 2023 which led to higher storage levels.[4]
- There were more nuclear generator outages in Spring 2023 than in Spring 2022 (up ~370 MW). Additionally, net imports averaged 276 MW less compared to the previous spring. These factors somewhat offset the impact of lower natural gas prices on LMPs.
- Energy market prices did not differ significantly among load zones.

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[3] 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. CSO payments are not enough to cover the AFRR, and the supplemental payments fill the gap. Any additional revenues they receive are netted so revenues are capped at the AFRR.

[4] U.S. dry natural gas production set a monthly record in April 2023 (104 billion cubic feet per day), and natural gas storage inventories were 15% higher than the five-year average at the end of May 2023, per the natural gas production and prices discussions in [EIA's Short Term Energy Outlook data](#).

Net Commitment Period Compensation (NCPC): NCPC payments totaled $3.9 million, down 64% or $6.9 million compared to Spring 2022. NCPC comprised 0.4% of total energy costs, a similar share to other quarters over the reporting period. In dollar terms, NCPC costs were the lowest in the 2 ½ year period covered in this report. The year-over-year decrease was due to a decline in first contingency (also known as "economic") payments and was in line with lower energy prices.

Real-time Reserves: Real-time reserve payments totaled $0.09 million, a $4.3 million decrease from $5.2 million in Spring 2022. Most payments (80%) were for ten-minute spinning reserve (TMSR). The low payments reflected high margins and the absence of major instances of stressed system conditions.

The frequency of non-zero spinning reserve prices decreased from 406 hours to 149 hours due to lower spinning reserve requirements. On May 31, 2022, an operational change reduced the percentage of the ten-minute reserve requirement that must be on-line (spinning) from 31% to 25%.[5] The average non-zero spinning reserve price also decreased relative to Spring 2022, from $16.98 to $9.16/MWh. While the average ten-minute non-spinning reserve (TMNSR) price in Spring 2023 was high ($84.76/MWh), the occurrence of non-zero pricing was less than two hours. There was no thirty-minute operating reserve (TMOR) pricing in Spring 2023.

Regulation: Regulation market payments totaled $4.8 million, down 23% from $6.2 million in Spring 2022. This decrease primarily reflected lower regulation capacity prices. Reduced capacity prices resulted from lower energy market opportunity costs (i.e., lower energy prices) compared to the previous spring.

Financial Transmission Rights (FTRs): FTRs in March, April, and May 2023 were fully funded. Lower day-ahead prices contributed to lower day-ahead congestion revenue and target allocation values in Spring 2023. Day-ahead congestion revenue decreased by 71% compared to Spring 2022, totaling $4.7 million. Positive target allocations totaled $4.8 million in Spring 2023, down 67% from Spring 2022. Negative target allocations (-$0.6 million) were 55% lower than their Spring 2022 level. Real-time congestion revenue in Spring 2023 ($0.5 million) remained modest and was in line with recent historical levels. At the end of May 2023, the congestion revenue fund had a surplus of $3.8 million.

Energy Market Competitiveness: The residual supply index for the Real-Time Energy Market in Spring 2023 was 108, indicating that the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier, on average. There was at least one pivotal supplier present in the real-time market for 22% of five-minute pricing intervals in Spring 2023. This was similar to the frequency of pivotal suppliers during the previous spring (22%).

Mitigation continued to occur very infrequently. During Spring 2023, mitigation asset-hours represented just 0.02% of total-asset hours. Mitigation frequency decreased compared to Spring

[5] The operational decision to change this percentage stemmed partly from an enhancement of the Energy Management System (EMS) that led to more accurate accounting of reserves.

2022 (0.05% of total asset-hours) due to a decline in manual dispatch energy and start-up and no-load mitigation, which was partially offset by an increase in reliability commitment mitigation.

***Summer 2023 Forward Reserve Market Auction*:** In April 2023, ISO New England held the forward reserve auction for the Summer 2023 delivery period (i.e., June 1, 2023 to September 30, 2023). System-wide supply offers in the Summer 2023 auction exceeded the requirements for both TMNSR and TMOR.

The system TMOR and TMNSR products both cleared at prices of $7,499/MW-month. The Summer 2023 TMOR price increased significantly compared to previous auctions. The Summer 2023 auction had slightly less TMOR supply (~130 MW) and a small increase in the incremental TMOR requirement. To meet the auction's total thirty reserve requirement, TMNSR was substituted for TMOR and both products cleared at the same price. The Summer 2023 TMNSR price was similar to that of the Summer 2022 auction.

The Residual Supply Index (RSI) for the system-level TMNSR product in Summer 2023 was 81, which was below the structurally competitive level of 100 and similar to the Summer 2022 value of 78. TMNSR supply in the Summer 2022 and 2023 auctions declined by about 700-800 MW compared to the Summer 2021 auction. The system-wide total thirty-minute RSI for Summer 2023 of 86 was also structurally uncompetitive, and similar to the Summer 2022 RSI of 90. These results were driven by small increases in the total thirty requirement, coupled with a decline in total thirty supply of about 1,000 MW compared to the Summer 2021 auction.

The IMM is concerned that the forward reserve auctions, which have been structurally uncompetitive in the five most-recent summer auctions, are susceptible to participants exercising market power. After reviewing and assessing the results of the most recent auction the IMM cannot conclude that prices were the result of competitive offers. This assessment was informed by both a top-down assessment of a range of competitive bids as well as an outreach to a number of participants in the auction.

To limit the potential exercise of market power, the forward reserve auctions utilize a price cap (i.e., an upper bound on reasonably competitive supply offer prices). Based on our review of inputs into the price cap formulation, we believe it would be prudent to update the cap based on prevailing market and system conditions. Our review suggests that the current price cap substantially overstates a reasonable upper bound on competitive forward reserve supply offers. We therefore recommend recommends that price cap be reduced from its current value of $9,000/MW-month; our analysis indicates that a value of approximately $6,600/MW-month would be more appropriate and reasonable.

Further, given the frequency of structurally-uncompetitive forward reserve auctions and elevated offer pricing in the summer 2023 auction, we are concerned that the publication of auction offer data may provide strategic information to participants in the auctions. We recommend that the ISO cease the publication of auction offer data or delay publication until several auction cycles have passed.

Section 2
Overall Market Conditions

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

Table 2-1: High-Level Market Statistics

Market Statistics	Spring 2023	Winter 2023	Spring 2023 vs Winter 2023 (% Change)	Spring 2022	Spring 2023 vs Spring 2022 (% Change)
Real-Time Load (GWh)	25,796	29,977	-14%	26,886	-4%
Peak Real-Time Load (MW)	16,203	19,663	-18%	18,948	-14%
Average Day-Ahead Hub LMP ($/MWh)	$29.62	$78.29	-62%	$68.49	-57%
Average Real-Time Hub LMP ($/MWh)	$27.04	$79.52	-66%	$66.91	-60%
Average Natural Gas Price ($/MMBtu)	$2.24	$9.15	-75%	$7.14	-69%
Average No. 6 Oil Price ($/MMBtu)	$15.92	$17.05	-7%	$24.35	-35%

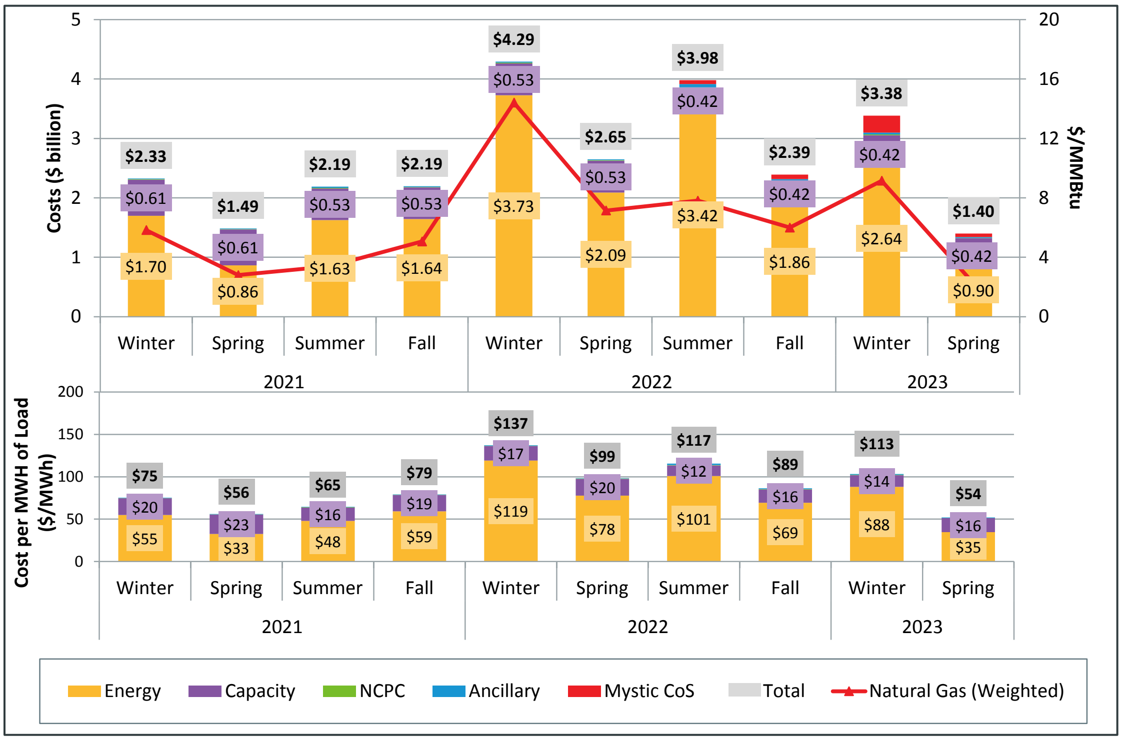
To summarize the table above:

- Day-ahead LMPs averaged $29.62/MWh in Spring 2023, down 57% from Spring 2022 ($68.49/MWh). Lower gas prices in Spring 2023 ($2.24/MMBtu) compared to Spring 2022 ($7.14/MMBtu) put downward pressure on LMPs.
- Energy prices did not decrease by as much as natural gas prices year-over-year (57% vs. 69%) because Spring 2023 saw more baseload generator outages and lower net imports than Spring 2022. The 75% decline in natural gas prices compared to Winter 2023 was driven by a decrease in natural gas demand.
- Total load in Spring 2023 (25,796 GWh, or an average of 11,688 MW per hour) was 4% lower than in Spring 2022 (26,866 GWh).

2.1 Wholesale Cost of Electricity

The estimated wholesale cost of electricity (in billions of dollars), categorized by cost component, is shown by season in the upper panel of Figure 2-1 below.[6] The upper panel also shows the average price of natural gas price (in $/MMBtu) as energy market payments in New England tend to be correlated with the price of natural gas in the region.[7] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

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



In Spring 2023, the total estimated wholesale cost of electricity was $1.40 billion (or $54/MWh of load), a 47% decrease compared to $2.65 billion in Spring 2022 and a 59% decrease compared to $3.38 billion in Winter 2023. The decrease from Spring 2022 was driven by a sharp decline in energy costs. The share of each wholesale cost component since Winter 2021 is shown in Figure 2-2 below.

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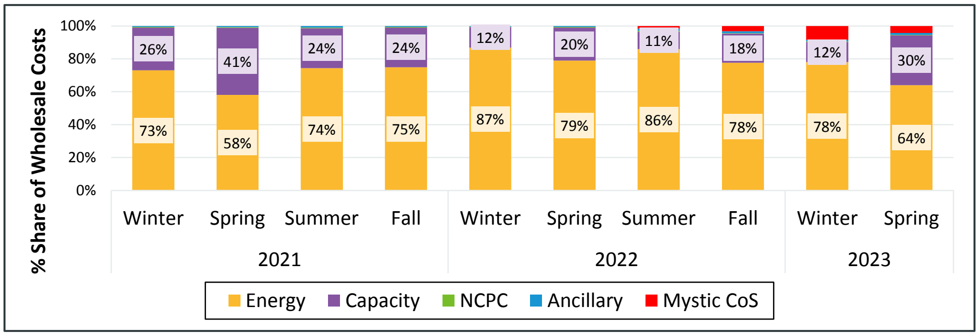
[6] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

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

Figure 2-2: Percentage Share of Wholesale Costs



Energy costs, which comprised 64% of the total wholesale cost, were $0.90 billion ($35/MWh) in Spring 2023, 57% lower than Spring 2022 costs, driven by a 69% decrease in natural gas prices. Natural gas prices continued to be a key driver of energy prices. Increased baseload outages and fewer net imports partially muted the impact of lower natural gas prices on LMPs.

Capacity costs depend heavily on the clearing price in the primary capacity auction (in this reporting period, FCA 13), and totaled $423 million ($16/MWh), representing 30% of total costs. The current capacity commitment period (CCP 13, June 2022 – May 2023) cleared at $3.80/kw-month. This was 18% lower than the primary auction clearing price of $4.63/kW-month for the prior capacity commitment period. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

Beginning in Summer 2022, the Mystic 8 and 9 generators began receiving supplemental payments per their cost-of-service agreement (Mystic CoS) with the ISO. These payments totaled $59.8 million in Spring 2023. Mystic 8 and 9 will receive supplemental payments until May 2024.

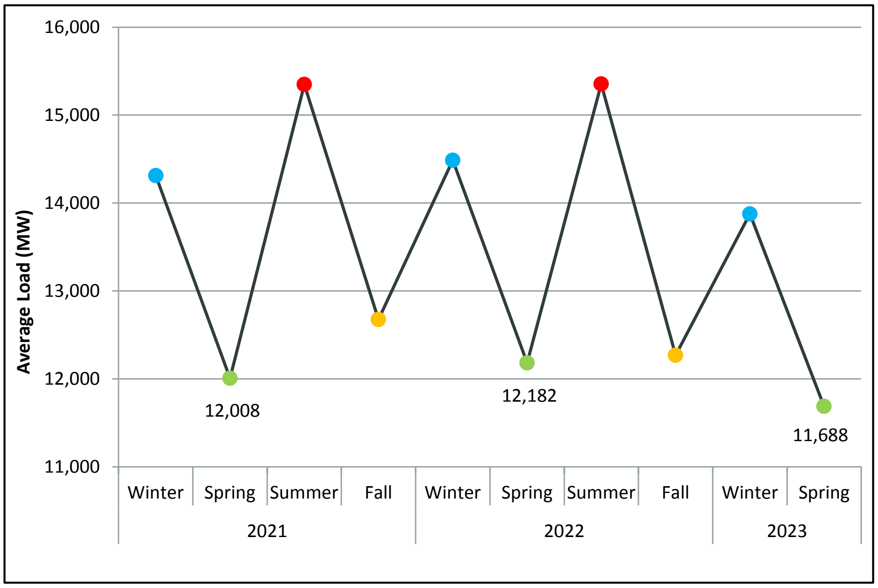
At $3.9 million ($0.15/MWh), Spring 2023 Net Commitment Period Compensation (NCPC) costs represented 0.4% of total energy costs, a similar share to other quarters over the reporting period. In dollar terms, NCPC costs were the lowest of the study period, and $6.9 million (or 64%) lower than in Spring 2022. The decrease was driven by a decline in first contingency payments.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $16.4 million ($0.64/MWh) in Spring 2023, representing 1% of total wholesale costs. Ancillary service costs increased by 12% compared to Spring 2022 costs due to higher forward reserve payments. When compared to Winter 2023, ancillary service costs were down by 44%.

2.2 Load

In Spring 2023, average load decreased 4% compared to Spring 2022 due to cooler weather, especially during May 2023. Growing behind-the-meter photovoltaic generation and energy efficiency continued to contribute to lower loads in every month.[8] Average hourly load by season is illustrated in Figure 2-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 2-3: Average Hourly Load by Quarter



In Spring 2023, hourly loads averaged 11,688 MW, the lowest load over the ten season period. Average load fell year-over-year due to cooler weather leading to less air-conditioning demand during May 2023. Additionally, behind-the-meter photovoltaic generation increased from 566 MW to 647 MW, on average, contributing to lower wholesale load.

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

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (right axis) to the monthly total number of degree days (left axis).[9]

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

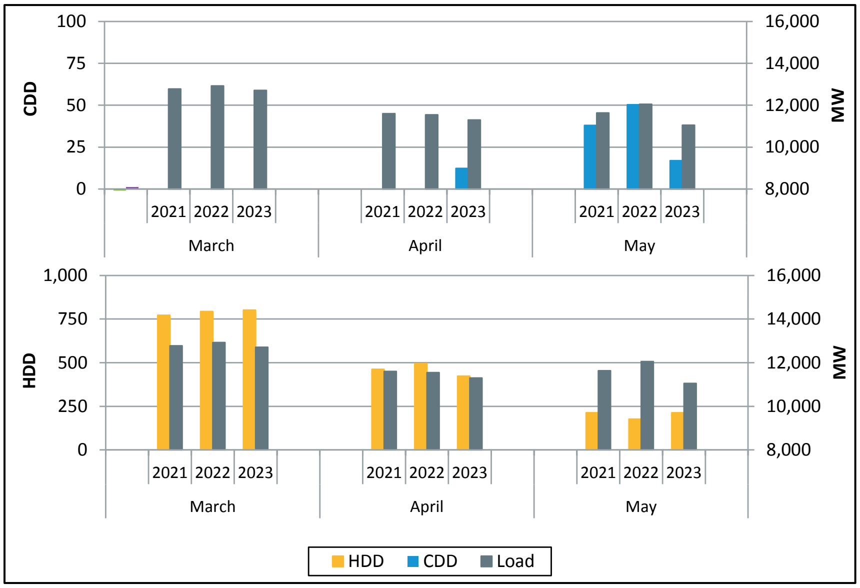


Figure 2-4 shows that average monthly load decreased in all three months compared to the prior year. In March 2023 and April 2023, average load decreased by 2%. With similar temperatures and total degree days, the change in load continues the longer term trend of decreasing loads due to energy efficiency and behind-the-meter photovoltaic generation.[10] However, average loads in May 2023 (11,047 MW) decreased by 1,004 MW (or 8%) compared to May 2022. Lower loads were driven by cooler temperatures. In May 2023, temperatures averaged 59°F, a 2°F decrease compared to May 2022. In May 2023, the temperature-humidity index (THI) peaked above 70 on just two days compared to nine days in May 2022.[11] Behind-the-meter photovoltaic generation also contributed to the decrease in load. In May 2023, behind-the-meter photovoltaic generation grew by nearly 180 MW year-over-year (864 MW vs. 685 MW) the highest monthly increase during the spring.

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[9] Cooling degree day (CDD) measures how warm an average daily temperature is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is 5. Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the HDD for that day is 5.

[10] Average behind-the-meter photovoltaic generation increased year-over-year by an estimated 48 MW in March 2023 (470 MW) and 16 MW in April 2023 (607 MW).

[11] The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (°F)] + 0.3 x [Dew Point (°F)] + 15.

Peak Load and Load Duration Curves

New England's system load over the past three spring seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher.

Figure 2-5: Load Duration Curves

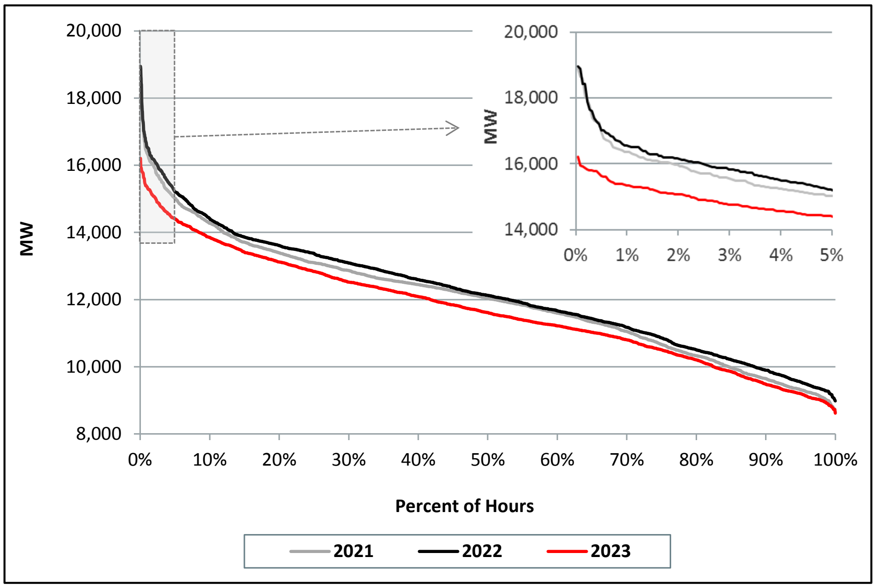
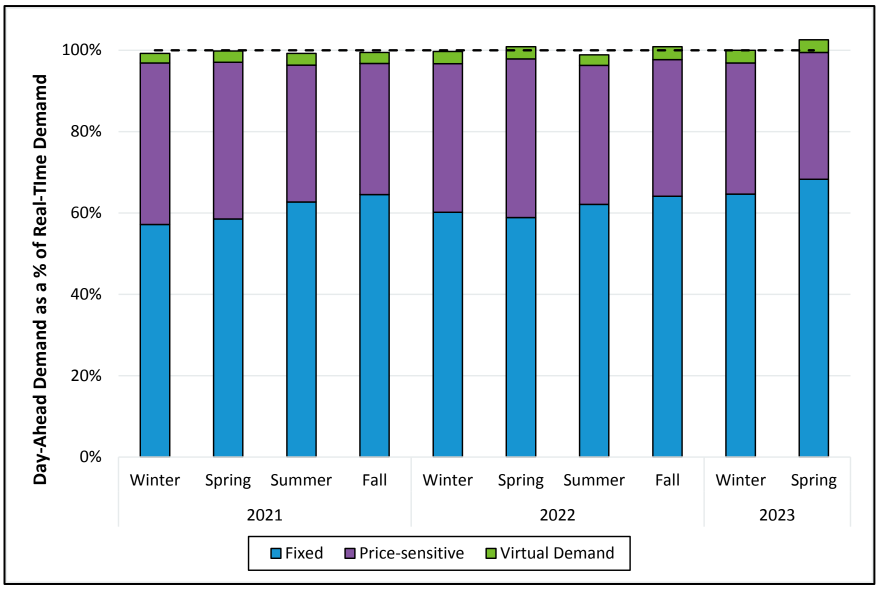


Figure 2-5 shows that loads in Spring 2023 were lower across all hours when compared to both Spring 2022 and 2021. In Spring 2023, peak loads (inset graph) were much lower than in the prior two springs. In the top 5% of all hours, load averaged 14,975 MW in Spring 2023, which was 1,154 MW lower than in Spring 2022 and 926 MW lower than in Spring 2021. In Spring 2023, the peak load (16,203 MW) was lower than the 37 highest load hours during Spring 2022. These high load hours occurred on either hot and humid days during May 2022 or during periods of cold weather in March 2022.

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.[12] Low demand clearing in the day-ahead market may warrant supplemental generation commitments to meet real-time demand. Commitments that occur after the day-ahead market process can lead to higher real-time prices compared to day-ahead prices, assuming all else equal. The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below. Day-ahead demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[13]

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



In Spring 2023, participants cleared an average of 103% of their real-time demand in the day-ahead market, which was up from 100% in Spring 2022. Participants cleared higher levels of fixed demand (68% vs. 59%) compared to Spring 2022. Virtual demand's contribution remained around 3% of total cleared demand. However, decreased levels of price-sensitive demand offset some of the increase in fixed demand. In Spring 2023, price-sensitive demand accounted for 31% of real-time demand compared to 39% in Spring 2022. Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of these bids are priced well above the day-ahead LMP. Such transactions are, in practical terms, fixed demand bids. Therefore, the shift from price-sensitive demand bids to fixed demand bids resulted in no significant market impacts.

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[12] 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.

[13] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. This is different from the ISO Express report, which defines day-ahead cleared demand as fixed demand + price-sensitive demand + virtual demand - virtual supply + asset-related demand. Real-time load is calculated as generation – asset-related demand + price-responsive demand + net imports – losses. We have found that comparing the modified definition of day-ahead cleared demand and real-time metered load can provide better insight into day-ahead and real-time price differences.

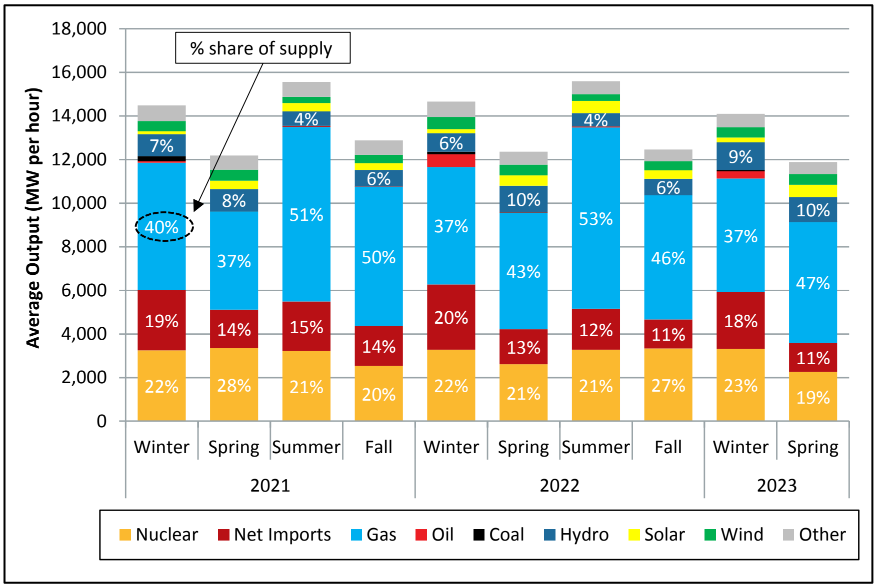
2.3 Supply

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

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The shares of energy production by generator fuel type for Winter 2021 through Spring 2023 are illustrated in Figure 2-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of generation from that fuel type.[14]

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



Average output in Spring 2023 (11,884 MW per hour) was 477 MW per hour less than in Spring 2022 (12,362 MW per hour). The largest season-over-season decrease occurred in nuclear generation, which fell by 354 MW per hour between Spring 2022 (2,609 MW per hour) and Spring 2023 (2,256 MW per hour). This decrease in nuclear generation was largely driven by the planned refueling outages of two nuclear power plants. Net imports (imports netted for exports) also decreased, falling from 1,605 MW per hour in Spring 2022 to 1,329 MW per hour in Spring 2023. The decrease in net imports occurred at every external interface with the exception of the New York North interface, where net imports increased modestly.[15] Meanwhile, gas generation had the largest season-over-season increase, rising from 5,342 MW per hour in Spring 2022 to 5,549 MW per hour in Spring 2023. Gas generation, which accounted for 47% of total energy production in Spring 2023, has represented the highest share of energy production by a fuel source throughout the reporting period.

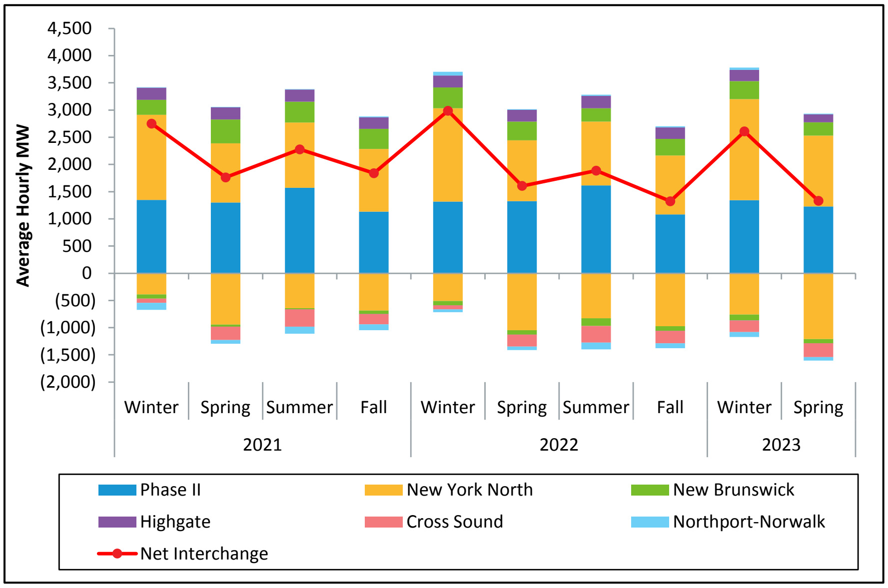
[14] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response.

[15] See Section 2.3.2 for more information about imports and exports.

2.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Spring 2023.[16] On average, the net flow of energy into New England was 1,329 MW per hour. Total net interchange represented 11% of load (NEL), similar to levels from Spring 2022 (13%). The average hourly import, export, and net interchange power volumes by external interface for the last ten seasons are shown in Figure 2-8 below.

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



Hourly net interchange averaged 1,329 MW, down 49% from Winter 2023. Net interchange increases during the winter when cold weather leads to a constrained natural gas system in New England. During the winter, natural gas-fired generators compete with heating demand for limited natural gas supply. This leads to upward pressure on natural gas and LMPs during the winter and incentivizes higher volumes of imports from neighboring regions. These conditions are infrequent during the spring, leading to less power delivered into New England from neighboring areas. Outages of transmission elements often increase during the spring, which further contributes to the lower volumes of net interchange compared to winter.

Compared to Spring 2022, hourly net interchange decreased by 17% year-over-year. New England imported less power from all three Canadian interfaces compared to Spring 2022. Decreased interchange across the Canadian interfaces accounted for 96% of the system-level decrease in average net interchange. Phase II saw the largest decrease in net interchange falling from 1,327 MW to 1,225 MW. Net interchange with New Brunswick (167 MW) fell by 98 MW compared to Spring 2022 (265 MW). In both Spring 2023 and Spring 2022, a nuclear generator in New Brunswick took a longer-than-planned outage, and net interchange remained below levels in Spring 2021 (403

[16] 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.

MW).[17] At the Highgate interface, average net interchange fell by 64 MW compared to Spring 2022 (148 MW vs. 212 MW). Imports from Canada can vary based on the price in New England. This relationship also occurs during the operating day as net interchange increases when load and LMPs increase. From hour ending (HE) 18 to HE 23, net interchange at the Canadian interfaces averaged 1,754 MW compared to an average of 1,469 MW during the rest of the operating day. At the New York interfaces, New England continued to be a net exporter of power; exporting an average of 49 MW and 256 MW over the Northport-Norwalk and Cross Sounds Cable interfaces, respectively and importing an average of 94 MW over the New York North interface. All three interfaces saw year-over-year differences of less than 40 MW.

[17] For more information on the nuclear generator outage see: https://www.nbpower.com/en/about-us/news-media-centre/news/2023/point-lepreau-nuclear-generating-station-reconnects-to-the-new-brunswick-grid-1/

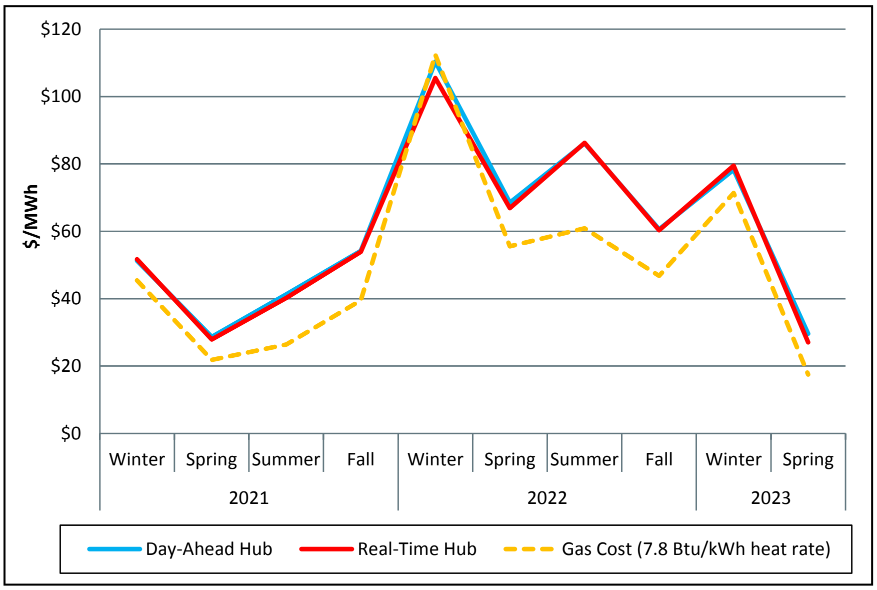
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. These trends can be seen in Figure 3-1, which shows the average day-ahead and real-time energy prices, along with the estimated cost of generating electricity using natural gas in New England.[18]

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



The average real-time and day-ahead Hub prices for Spring 2023 were $27.04 and $29.62/MWh, respectively. Gas costs averaged $17.50/MWh in Spring 2023. The average real-time price was $2.58/MWh lower than the average day-ahead price due to several factors, including low midday loads, additional fixed-price generation in real time compared to the day-ahead schedule, and large volumes of additional real-time renewable generation compared to the day-ahead schedule during certain hours.

The spread between the average day-ahead electricity price and average estimated gas cost was $12/MWh in Spring 2023, similar to the $13/MWh spread in Spring 2022 but higher than the $7/MWh in Spring 2021. The higher spread in Spring 2022 resulted from substantial increases in natural gas prices and baseload generator outages compared to Spring 2021. A nuclear generator had a planned refueling outage for several weeks in Spring 2022, and the average out-of-service capacity for nuclear generators rose by 734 MW compared to Spring 2021. In Spring 2023, nuclear

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

generator outages rose to 1,110 MW due to two planned refueling outages. These baseload outages, coupled with lower net imports, resulted in the dispatch of less efficient, higher cost gas generation.

Average day-ahead and real-time prices in Spring 2023 were lower than Spring 2022 prices by $38.87/MWh (down 57%) and $39.87 (down 60%), respectively. These decreases are consistent with lower natural gas prices in Spring 2023, which fell by 69% compared Spring 2022. Less nuclear generation and net imports in Spring 2023 partially muted the impact of lower natural gas prices on LMPs. Prices did not differ significantly among the load zones in either market in Spring 2023, indicating that there was relatively little transmission congestion on the system at the zonal level.

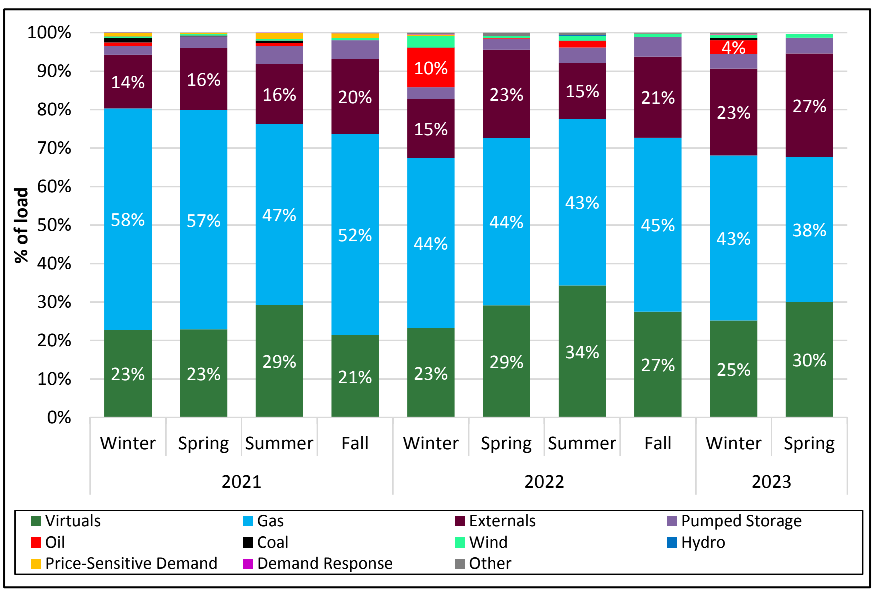
3.2 Marginal Resources and Transactions

This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Day-Ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2021 is illustrated in Figure 3-2 below.

Figure 3-2: Day-Ahead Marginal Units by Transaction and Fuel Type

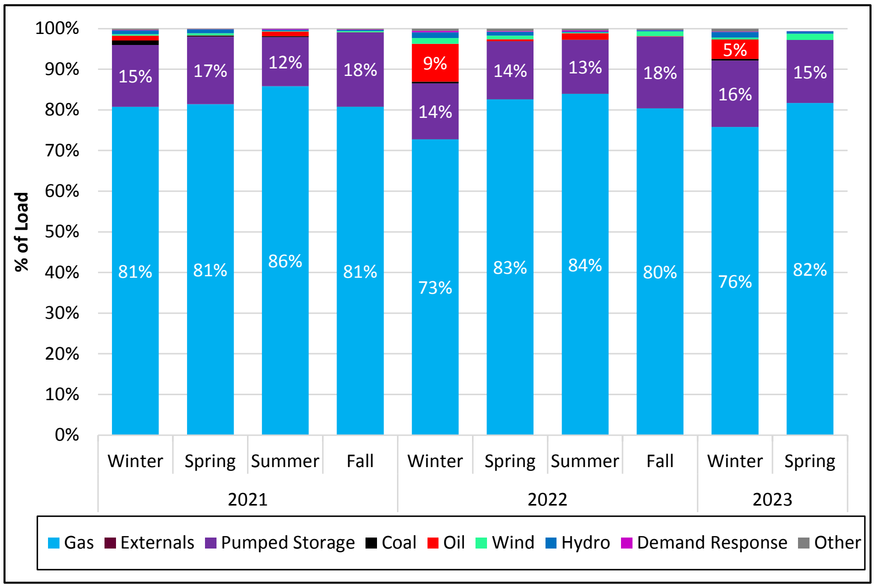


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 38% of total day-ahead load in Spring 2023. Virtual transactions and external transactions were next, setting price for 30% and 27% of load, respectively. Other fuel types were collectively marginal for less than 6% of load.

Real-Time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2021 is shown in Figure 3-3 below.[19]

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



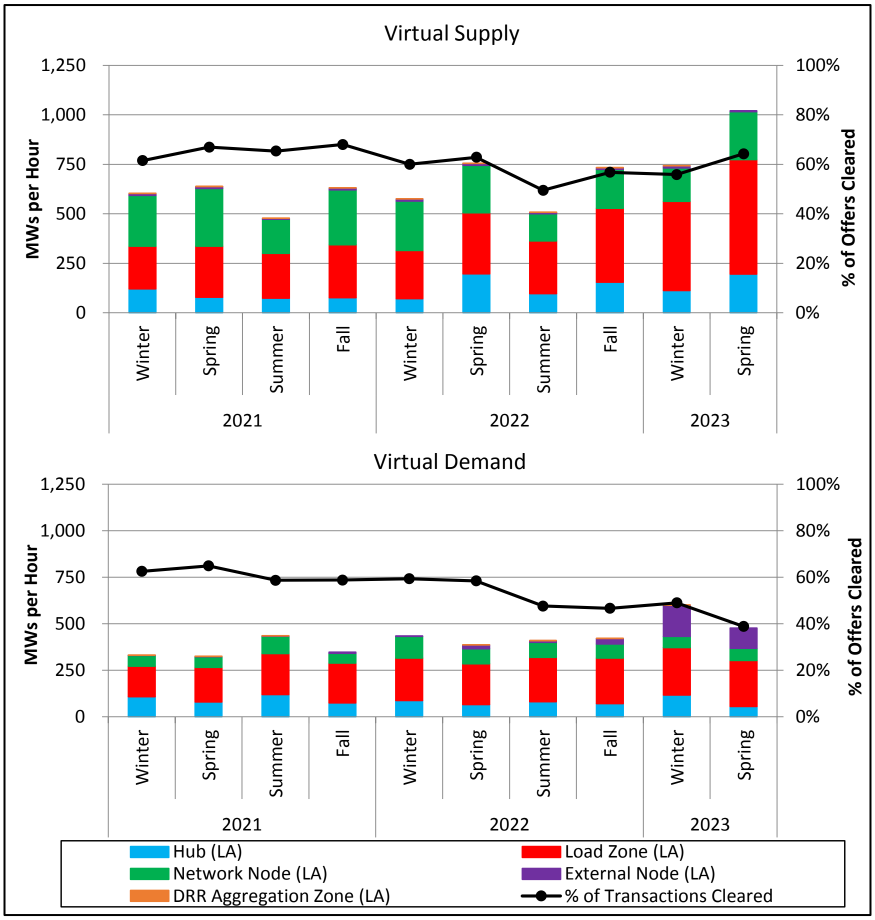
Similar to the day-ahead market, natural gas-fired generators set price for highest percentage of load in the real-time market in Spring 2023 (82%). Pumped storage (generation and demand) was the marginal fuel for the second largest share of load in Spring 2023 (15%). While wind units are frequently marginal in real time, the load within the constrained areas where they set price tends to be quite small. In Spring 2023, wind units were the marginal fuel type for less than 2% of real-time load.

3.3 Virtual Transactions

In the Day-Ahead Energy Market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model 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 3-4 below. Cleared transactions are divided into groups 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.

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

Figure 3-4: Cleared Virtual Transactions by Location Type



In Spring 2023, total cleared virtual transactions averaged approximately 1,499 MW per hour, a 31% increase compared to Spring 2022 (1,141 MW per hour).

Total cleared virtual supply averaged 1,021 MW per hour in Spring 2023, up 35% from Spring 2022 (755 MW per hour). Virtual supply generally clears at higher volumes than virtual demand due to the growing amount of solar settlement-only generation (SOG) and the day-ahead bidding behavior of wind generation. By the end of Spring 2023, solar SOGs reached an installed capacity of over 2,000 MWs. Since settlement-only generators do not participate in the day-ahead market, participants clear virtual supply on days where solar generation is expected to be high. In Spring 2023, participants cleared an average of 579 MW of virtual supply at load zones compared to 249 MW of virtual demand. Larger volumes of virtual supply also clear at network nodes compared to virtual demand. This activity is often related to virtual participants trying 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.[20]

Cleared virtual demand averaged 477 MW per hour in Spring 2023, up 24% from Spring 2022 (386 MW per hour). In Spring 2023, participants cleared 23% of their virtual demand bids (or 110 MW)

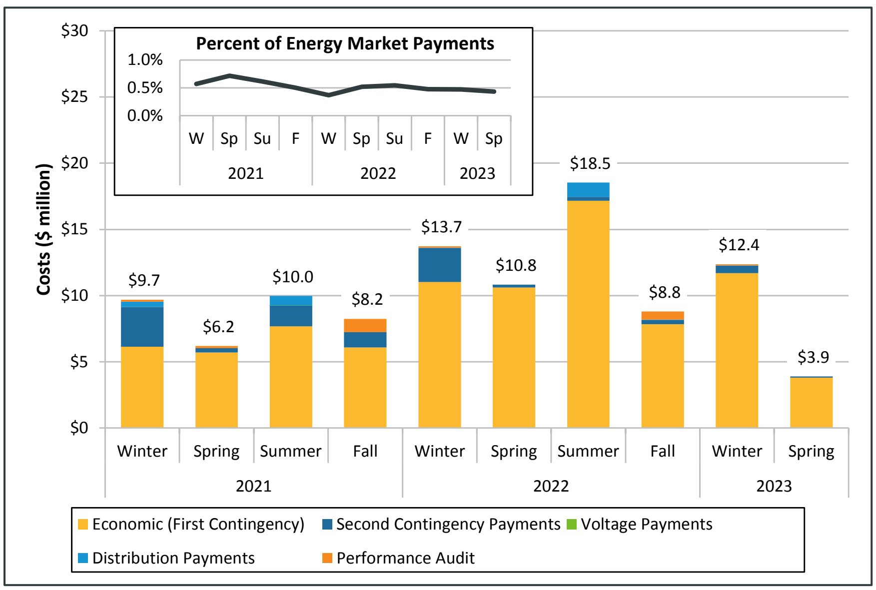
[20] In Winter 2023, real-time wind generation averaged 470 MW.

at external nodes. Most of the year-over-year increase was driven by higher cleared volumes at the Highgate interface, which connects New England with the Hydro-Québec control area. Beginning in Winter 2023, higher volumes of virtual demand cleared at Highgate, providing participants with: (1) a financial hedge on deviations between day-ahead and real-time imports at the Highgate interface, or (2) counter-flow transactions allowing for greater than 225 MW of imports, the total transfer capability (TTC) of the interface.[21] In Spring 2023, participants cleared an average of 85 MW per hour at Highgate. While this was lower than Winter 2023, participants cleared less than 1 MW per hour during the prior eight seasons (Winter 2021 to Fall 2022).

3.4 Net Commitment Period Compensation

Net commitment period compensation (NCPC) during Spring 2023 totaled $3.9 million, its lowest level in the study period. NCPC was 0.4% of energy market payments in Spring 2023, consistent with rest of the reporting period.[22] Figure 3-5 below, shows NCPC paid in each of the last ten seasons, segmented by category. The inset chart shows NCPC as a percentage of energy market payments.

Figure 3-5: NCPC by Category

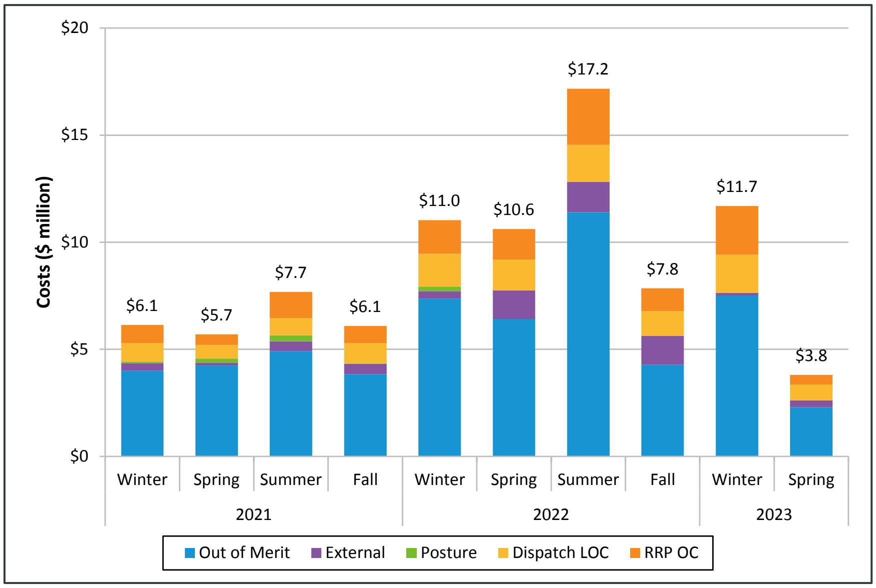


In Spring 2023, $3.8 million of the $3.9 million NCPC was economic. Seasonal economic NCPC is summarized by subcategory in Figure 3-6 below.

[21] An equivalent volume of day-ahead cleared imports and cleared virtual demand would remove exposure to day-ahead and real-time price differences if the real-time imports were curtailed in real time. Any real-time import deviations would be settled at a higher real-time price. However, virtual demand does not materialize in real time, and would also be profitable after being sold back at a higher real-time price.

[22] NCPC and energy market payments are positively correlated because they are both driven by generator costs.

Figure 3-6: Economic NCPC by Reason



Of the $3.8 million in economic NCPC paid in Spring 2023, $2.3 million was paid to units that did not recover their costs when following ISO instructions (out of merit). In Spring 2023, overall payments were low and distributed across many days and assets.[23] There were no days exceeding 5% of the total out of merit payments or individual assets that received more than 8% in the season. Dispatch Lost Opportunity Cost and Rapid-Response Pricing Opportunity Cost NCPC were about 30% of the total economic NCPC in the season, consistent with the rest of the study period. External payments totaled $326 thousand in the season. Nearly all (96%) of the external payments were across the three interfaces New England shares with Canada due to inaccurate price forecasts that were used to schedule real-time transactions.

The $89 thousand in NCPC paid in Spring 2023 that was not economic was for second contingency protection. All but $3 thousand was paid in the day-ahead market. Over 95% of the second contingency payments were made to two generators providing local protection in Maine and New Hampshire over two days in March. These units were committed for reliability due to a planned high-voltage transmission line outage impacting eastern New England.

[23] The term "assets" here refers to generators, asset-related demand, and demand response.

3.5 Real-Time Operating Reserves

This section provides details about real-time operating reserve pricing and payments.

Real-time Reserve Pricing

Real-time reserve pricing (that is non-zero) occurs when a resource incurs an opportunity cost as a result of providing reserves instead of energy. This happens when the reserve capability of the system only just meets a reserve requirement, and resources that would otherwise be profitable providing energy need to be compensated in order to instead provide reserves.[24] Consequently, periods with reserve pricing can be indicative of tight system conditions. The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three years is provided in Table 3-1 below.[25]

Table 3-1: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Spring 2023		Spring 2022		Spring 2021	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$9.16	148.8	$16.98	405.8	$7.85	325.0
TMNSR	**System**	$84.76	1.8	$290.32	3.0	$0.00	0.0
TMOR	**System**	$0.00	0.0	$193.40	1.9	$0.00	0.0
	NEMA/Boston	$0.00	0.0	$193.40	1.9	$0.00	0.0
	CT	$0.00	0.0	$193.40	1.9	$0.00	0.0
	SWCT	$0.00	0.0	$193.40	1.9	$0.00	0.0

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 149 hours (7% of total hours) during Spring 2023, which was 257 hours (63%) less than in Spring 2022 and 176 hours (54%) less than in Spring 2021. One of the primary reasons for the decrease in non-zero TMSR pricing was the result of an operational change that reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022.[26] This operational change contributed to reducing the average ten-minute spinning reserve requirement

[24] 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.2.7A of Market Rule 1.

[25] 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). Resources providing reserves during these periods receive real-time reserve payments.

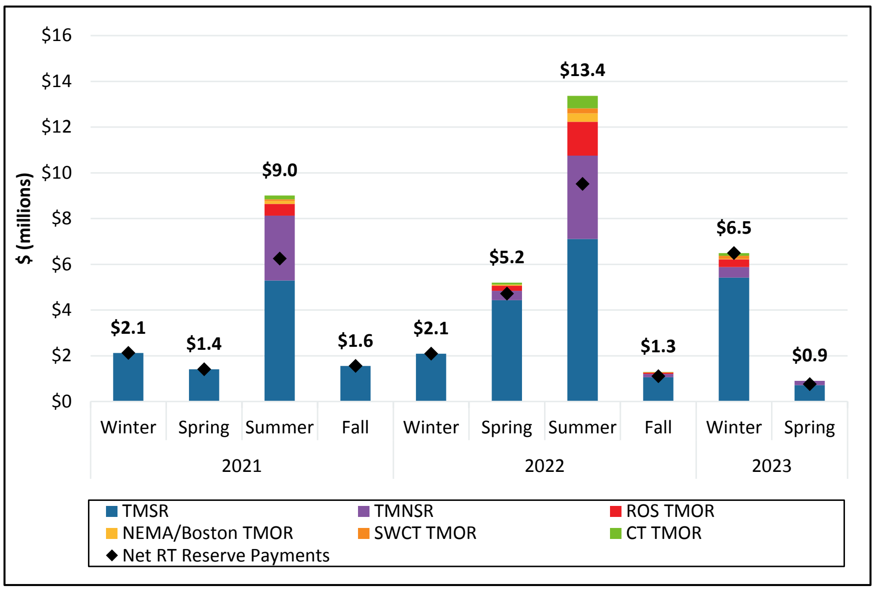
[26] The operational decision to change this percentage stemmed partly from an enhancement of the Energy Management System (EMS) that led to more accurate accounting of reserves.

from 484 MW in Spring 2022 to 382 MW in Spring 2023. The average price during intervals with non-zero TMSR pricing in Spring 2023 ($9.16/MWh), Spring 2022 ($16.98/MWh) and Spring 2021 ($7.85/MWh) generally moved in line with energy prices. Meanwhile, non-zero TMNSR and TMOR prices continued to occur very infrequently in Spring 2023.

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 3-7 below.[27] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Resources providing real-time reserves).[28]

Figure 3-7: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Spring 2023 ($0.9 million) were down considerably from Winter 2023 ($6.5 million) and from Spring 2022 ($5.2 million). One of the major reasons for the decrease relative to Winter 2023 was the large volume of reserve payments that were made on December 24, 2022, as a result of tight system conditions.[29] Net real-time reserve payments in Spring 2023 ($0.8 million) were only slightly reduced from their gross levels. The vast majority of reserve payments in Spring 2023 went to resources providing TMSR ($0.7 million), while a relatively small amount went to resources providing TMNSR ($0.2 million) and none went to resources providing TMOR.

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

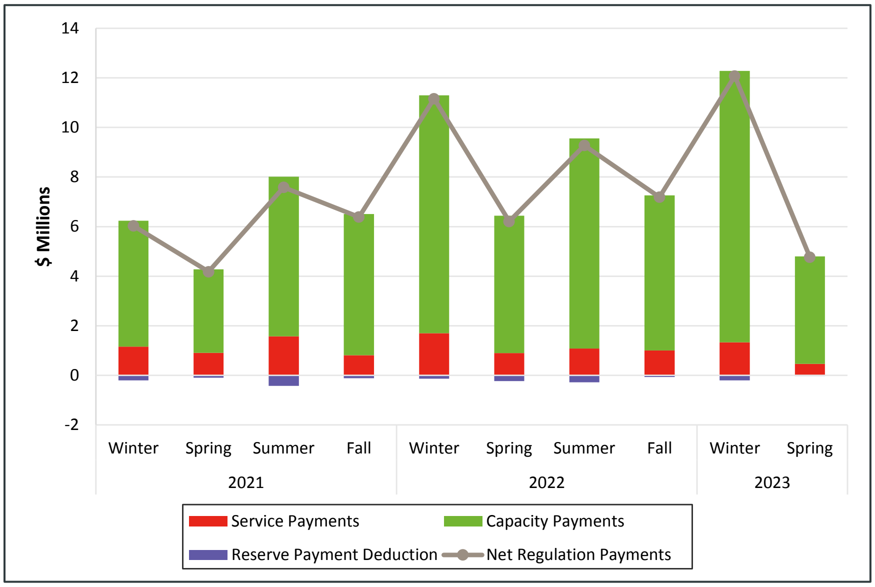
[28] The FRM is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a resource is not paid twice for the same service. For more information about forward reserve obligation charges, see Section III.10.4 of Market Rule 1.

[29] On this day alone, gross real-time reserve payments totaled $5.2 million. For more information about the market outcomes from this day, see the 2023 Winter Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2023/05/2023-winter-quarterly-markets-report.pdf.

3.6 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 3-8 below.

Figure 3-8: Regulation Payments



Total regulation market payments were $4.8 million during the reporting period, down approximately 61% from $12.1 million in Winter 2023 and down by 23% from $6.2 million in Spring 2022. The decrease in payments compared to the Winter period resulted predominately from significantly lower regulation capacity prices (49% decrease) and reduced regulation requirements (14% decrease) in Spring 2023. The decrease in capacity prices reflected declines in both lost opportunity costs (i.e., energy market prices) and incremental cost savings; the decline in regulation requirements reflected typical seasonal variation in those requirements. The decrease in regulation payments between Spring 2022 and Spring 2023 primarily reflected a decrease in capacity prices; the reduced capacity prices resulted from reduced energy market opportunity costs compared to the earlier period.

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. Section 4.1 evaluates energy market competitiveness at the quarterly level. First, this section presents two metrics on system-wide structural market power. Next, the section provides statistics on system and local market power flagged by the automated mitigation system. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the Real-Time Energy Market using two metrics: 1) the pivotal supplier test (PST) and 2) the residual supply index (RSI). Both of these metrics identify instances when the largest supplier has market power.[30] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand, and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[31] to the sum of each participant's total supply that is available within 30 minutes.[32] When a participant's available supply exceeds the supply margin, they are pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each quarter to obtain the percentage of intervals with pivotal suppliers.

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

[30] 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.

[31] 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*] -$Demand$ - [$Reserve\ Requirement$]

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

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

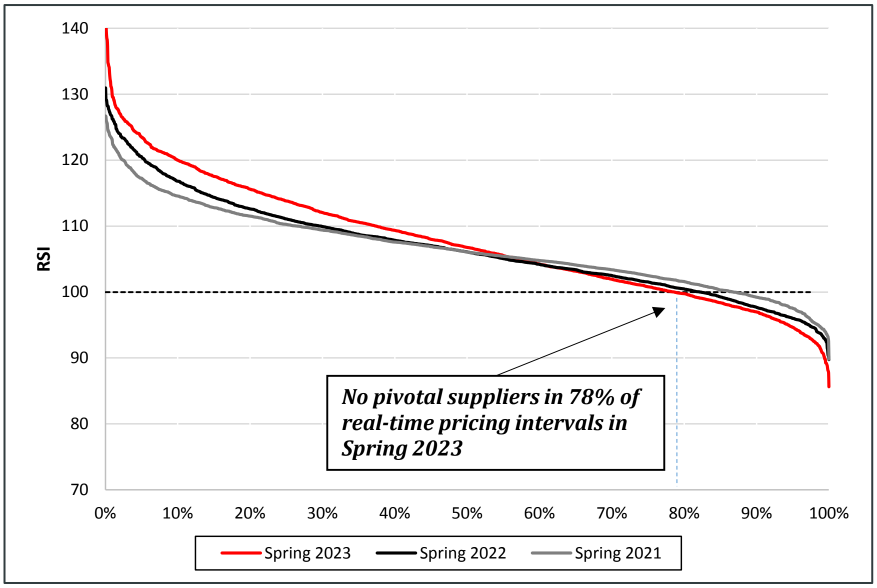
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%

The RSI was above 100 in every quarter of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The percentage of intervals with pivotal suppliers was relatively low most in quarters, indicating that there were typically limited opportunities for any one supplier to exercise market power.

The frequency of pivotal suppliers in Spring 2023 was 22%, which was just slightly higher than that of Spring 2022 (19%). The Spring 2023 reserve margin increased by about 300 MW on average compared to Spring 2022, but the average available supply from the largest supplier increased as well (by about 240 MW), resulting in a similar pivotal supplier frequency. There was more gas generation on the system in Spring 2023 than in Spring 2022 due to nuclear generator outages and decreases in net imports. This led to a participant supplying more gas generation compared to the previous spring.

Duration curves that rank the average hourly RSI over each spring quarter in descending order are illustrated in Figure 4-1 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 4-1: System-Wide Residual Supply Index Duration Curves



In Spring 2023, the RSI was higher than in the previous two springs across about half of the ranked observations. The lowest Spring 2023 value was 85.6, and occurred on April 19, when actual loads were 1,015-1,710 MW or 9-17% greater than the forecast for six hours during midday.

4.2 Energy Market Supply Offer Mitigation

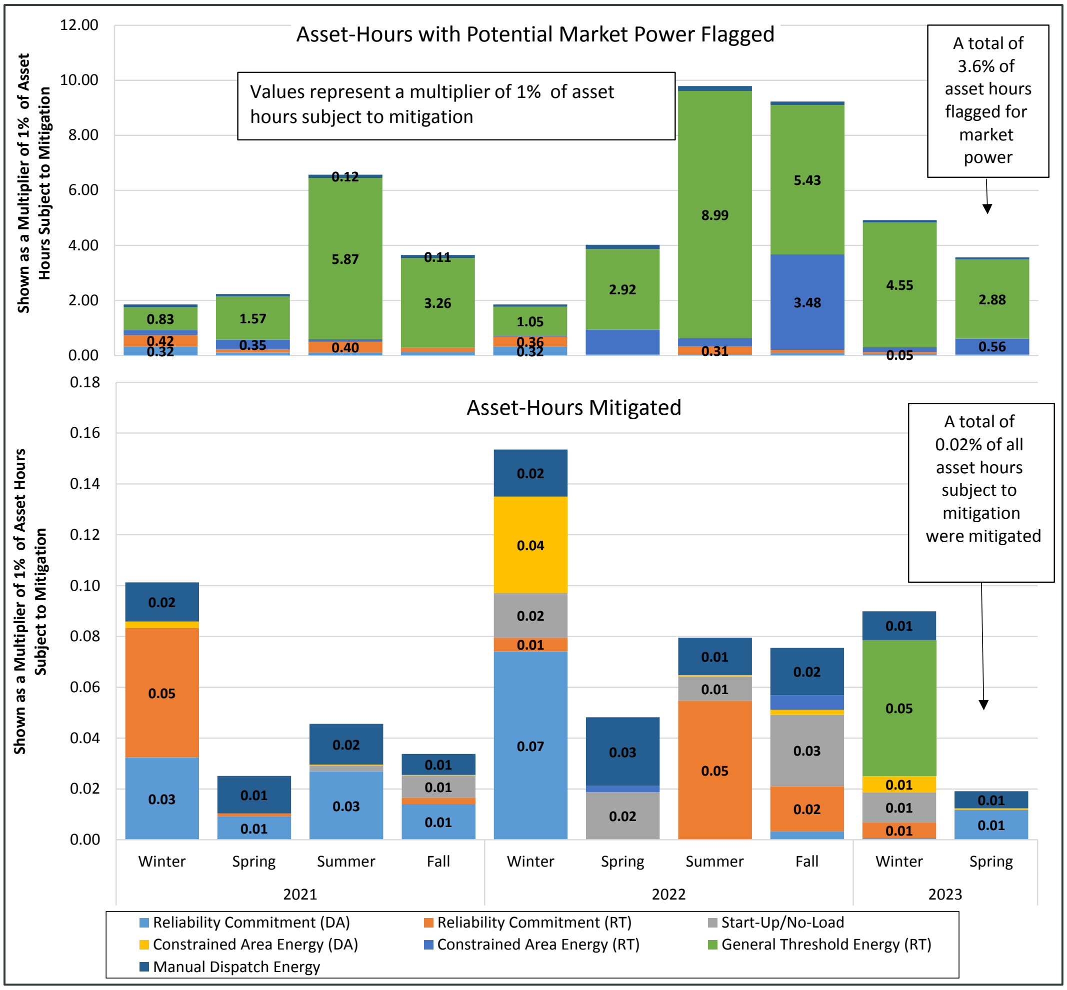
As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Spring 2023.

Energy Market Mitigation Frequency

This section summarizes three types of mitigation data: structural test failures, generator commitment or dispatch hours, and mitigation occurrences. An indication of mitigation frequency relative to opportunities to mitigate generators is illustrated in Figure 4-2 below.[33] It compares asset hours of structural test failures for dispatch and commitment (depending on mitigation type) to asset hours of mitigations. To provide additional context, the values in the figure have been scaled relative to one percent of total asset hours subject to potential mitigation.

[33] For example, a generator (asset) committed for reliability for a 12-hour period would represent 12 asset hours of commitment. If that asset were mitigated upon commitment, then 12 asset hours of mitigation would occur. For constrained areas, if 10 assets were located in an import-constrained area for two hours, then 20 asset hours of structural test failures would have occurred. If a pivotal supplier has seven assets and is pivotal for a single hour, then seven hours of structural test failures would have occurred for that supplier; however, more than one supplier may be pivotal during the same period (especially during tighter system conditions), leading to larger numbers of structural test failures than for other mitigation types. Manual dispatch energy commitment data indicate asset hours of manual dispatch (i.e., the asset hours when these generators are subject to commitment). Finally, SUNL commitment hours are not shown because mitigation hours equal commitment hours.

Figure 4-2: Energy Market Mitigation



In general, the data in Figure 4-2 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation: ISO commitment and operation of a generator and energy market mitigation thresholds (i.e., structural test failures, commitment or dispatch).[34] The highest frequency of mitigation occurs for reliability commitments (46% of all mitigations, light blue or orange shading in the figure); this results from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue, and yellow shading) have had the lowest mitigation frequency, with each accounting for 8 to 9% of mitigations over the review period.

The decrease in mitigations in Spring 2023, compared to the prior spring, resulted from a decline in manual dispatch energy and start-up and no-load mitigation, which was partially offset by an increase in reliability commitment mitigation. Comparing mitigations for Spring 2023 and Winter

[34] Because the general threshold commitment and constrained area commitment conduct tests did not result in any mitigations during the review period, those mitigation types have been omitted from the figure. The structural test failures associated with each mitigation type are the same as for the respective general threshold energy and constrained area energy structural test failures.

2023, mitigation decreased in Spring 2023 principally from a decline in general threshold energy mitigations. Overall, there were just 65 asset hours of mitigation in Spring 2023, while 340 thousand asset hours were potentially subject to mitigation.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[35] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, SEMA-RI and Maine had the highest frequency of reliability commitment asset hours, 43% and 35% respectively in the Day-Ahead Energy Market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past several years, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred frequently in SEMA-RI and Maine: 47% of mitigations occurred in SEMA-RI and 19% occurred in Maine in the day-ahead market.[36] Overall, reliability mitigations increased between Spring 2022 (0 asset hours) and Spring 2023 (40 asset hours); mitigations also increased in Spring 2023 relative to Winter 2023, going from 22 asset hours to 40. These mitigation levels are consistent with reduced reliability commitments in Spring 2022, Winter 2023 and Spring 2023. The three quarters combined had just 292 asset hours of reliability commitments.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[37] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. There were 0 asset hours of start-up and no-load mitigation in Spring 2023, compared to 64 asset hours of mitigation in Spring 2022 and 39 asset hours of mitigation in Winter 2023.

Constrained area energy (CAE) mitigation:[38] This mitigation type applies three tests prior to mitigation: structural, conduct and market impact. With relatively tolerant conduct and market impact test thresholds, the frequency of mitigation is low relative to the frequency of structural test failures. The frequency of mitigation given a structural test failure (i.e., generator located in an import-constrained area) in the Real-Time Energy Market has been approximately 0% (of structural test failure asset hours) over the review period, as only 25 asset hours of CAE mitigation have occurred in the Real-Time Energy Market and only 168 asset hours of mitigation have occurred in the Day-Ahead Energy Market. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within New England. In Spring

[35] 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. Market Rule 1, Appendix A, Section III.A.5.5.6.1.

[36] Reliability commitments are typically made in the day-ahead energy market and carry over to the real-time energy market. Hence, day-ahead reliability commitments account for approximately 69% of the reliability commitment asset hours in the real-time energy market.

[37] 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 reference values for those same parameters.

[38] Day-ahead energy market structural test failures are not being reported at this time. This results from questions about some of the source data for these failures. We expect to report on these structural test failures in future reporting.

2023, there were very few hours of structural test failures (1,904 asset hours) in the real-time market, and there were no asset hours of constrained area energy mitigation. In the day-ahead market for Spring 2023, there were just 2 asset hours of mitigation. Mitigations in Spring 2023 declined modestly compared to Spring 2022 (8 asset hours of mitigation) and Winter 2023 (21 asset hours).

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type typically has the lowest mitigation frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. This occurs in spite of this mitigation type having the highest frequency of structural test failures (i.e., pivotal supplier asset hours) for any mitigation type. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators. Two participants accounted for 69% of the structural test failures and five participants accounted for 84% of structural test failures over the review period.[39] Prior to Winter 2023, general threshold energy mitigation did not occur over the review period. During Winter 2023, however, there were 175 asset hours of general threshold energy mitigation. There were no general threshold energy mitigations in Spring 2023.

Manual dispatch energy mitigation: Manual dispatch energy mitigation occurs when a generator is manually dispatched by the ISO. Behind reliability commitment mitigation, this mitigation type occurs with the second highest frequency of any mitigation type (accounting for 23% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). Manual dispatch is relatively infrequent in the Real-Time Energy Market, with just a few hundred asset hours occurring each quarter. Combined-cycle generators have the highest frequency of manual dispatch; this is consistent with manual dispatch frequently occurring in the context of (1) regulation service provided to the Real-Time Energy Market and (2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address short-term issues on the transmission grid. In Spring 2023, there were 254 asset hours of manual dispatch and 23 asset hours of mitigation. These levels are roughly comparable to Winter 2023 (262 asset hours of manual dispatch and 37 asset hours of mitigation). The Spring 2023 values declined relative to Spring 2022, which had 536 asset hours of manual dispatch and 92 asset hours of mitigation.

[39] As noted in section 4.1 (Pivotal Supplier and Residual Supply Indices), the mitigation software's pivotal supplier test is different from the pivotal supplier metric presented in section 4.1 We have an outstanding recommendation that the ISO update the mitigation software's pivotal supplier test. (For example, see the recommendations section of the 2020 Annual Markets Report.)

Section 5
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2023 Forward Reserve Auction.

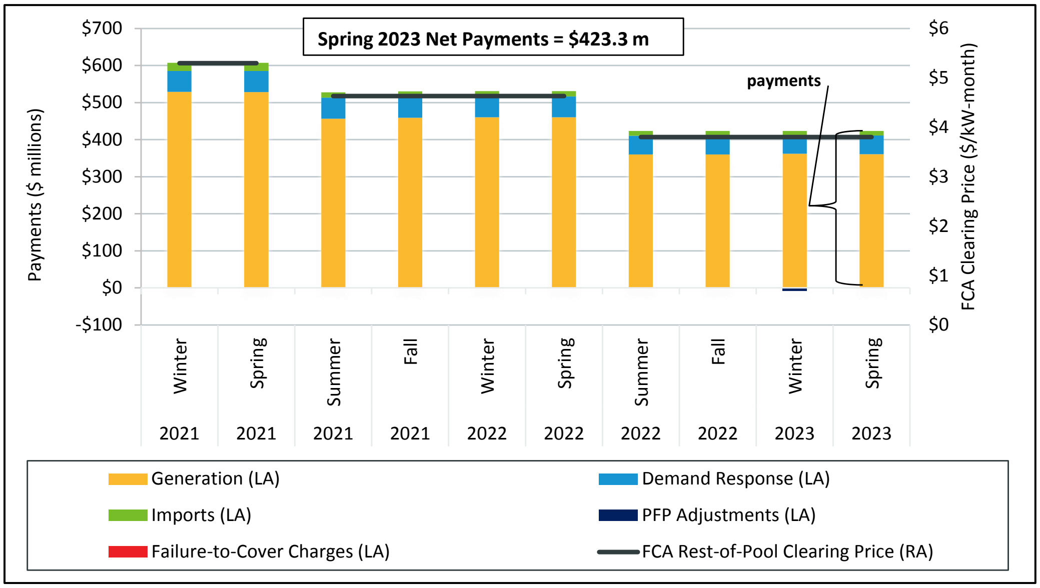
5.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Spring 2023 started on June 1, 2022 and will end on May 31, 2023. The corresponding Forward Capacity Auction (FCA 13) resulted in a lower clearing price than the previous auction while still obtaining sufficient resources needed to meet forecasted demand. The auction procured 34,839 megawatts (MW) of capacity, which exceeded the 33,750 MW Net Installed Capacity Requirement (Net ICR). During FCA 13, Killingly Energy Center added 632 MW of new gas/oil generation and Mystic 8 and 9 (~1,400 MW total) were retained by the ISO for winter fuel security.[40] The auction cleared at a price of $3.80/kW-month, 18% lower than the previous year's $4.63/kW-month. The $3.80/kW-month clearing price was applied to all capacity zones within New England. Price separation occurred at only one import interface; New Brunswick cleared capacity at a price of $2.68/kW month. The results of FCA 13 led to a total annual cost of $1.69 billion in capacity payments, $0.44 billion lower than capacity payments incurred in FCA 12.

Total FCM payments, as well as the clearing prices for Winter 2021 through Spring 2023, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, light blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance adjustments, while the red bar represents Failure-to-Cover charges.

[40] From June 2022 to May 2024, Mystic 8 and 9 will receive supplemental payments per their cost-of-service agreement with the ISO. Since June 2022, the two Mystic units received a total of $524.8 million in cost-of-service payments.

Figure 5-1: Capacity Market Payments



In Spring 2023, capacity payments totaled $423.3 million. Total payments were down 21% from Spring 2022 ($533.2 million), driven by an 18% decrease in the clearing price from FCA 12 ($4.63/kW-month) to FCA 13 ($3.80/kW-month). A large influx of lower-priced, new capacity displaced higher-priced, existing capacity in FCA 13; over 1,500 MW of new generation and demand response capacity offered at or below the auction clearing price while over 2,100 MW of existing generation and demand response capacity de-listed above the clearing price benchmark.

Approximately $39 thousand in Failure-to-Cover (FTC) charges were administered in Spring 2023. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover its CSO.

Following the primary auction, 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 Spring 2023 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

Table 5-1: Primary and Secondary Market Outcomes

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW**	Capacity Zone/Interface Prices ($/kW-mo)			
					Maine	Phase I/II	Highgate	New Brunswick
FCA 13 (2022 - 2023)	Primary	12-month	3.80	34,839				2.68
	Monthly Reconfiguration	May-23	1.00	1,136				
	Monthly Bilateral	May-23	1.58	90				
FCA 14 (2023 - 2024)	Primary	12-month	2.00	33,956				
	Annual Reconfiguration (3)	12-month	1.35	355, -614				
	Monthly Reconfiguration	Jun-23	2.01	925				
	Monthly Bilateral	Jun-23	2.00	5				
	Monthly Reconfiguration	Jul-23	2.00	985				
	Monthly Bilateral	Jul-23	0.82	13				

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

One annual reconfiguration auction took place in Spring 2023: the third annual reconfiguration auction for CCP 2023-2024. The auction cleared at $1.35/kW-month, below the primary auction clearing price of $2.00/kW-month for CCP 14 (2023-2024). In total, 335 MW of supply cleared against 614 MW of cleared demand. The over-clearing of demand led to 259 MW of capacity leaving the system for CCP 14, driven by an 800 MW (2%) decrease in Net ICR from FCA 14 to ARA 3.[41]

Three monthly reconfiguration auctions (MRAs) took place in Spring 2023: the May 2023 auction in March, the June 2023 auction in April, and the July 2023 auction in May. While auction clearing prices in the May 2023 auction remained below the associated primary auction clearing price, the latter two MRA auctions saw clearing prices much closer to their associated primary auction clearing price. Driven by high-priced demand participation, the June 2023 and July 2023 auctions cleared around the same price as FCA 14 at $2.00/kW-month. Cleared volumes remained relatively steady month-to-month, with the May 2023 auction clearing the largest volume at 1,136 MW.

5.2 Financial Transmission Rights

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

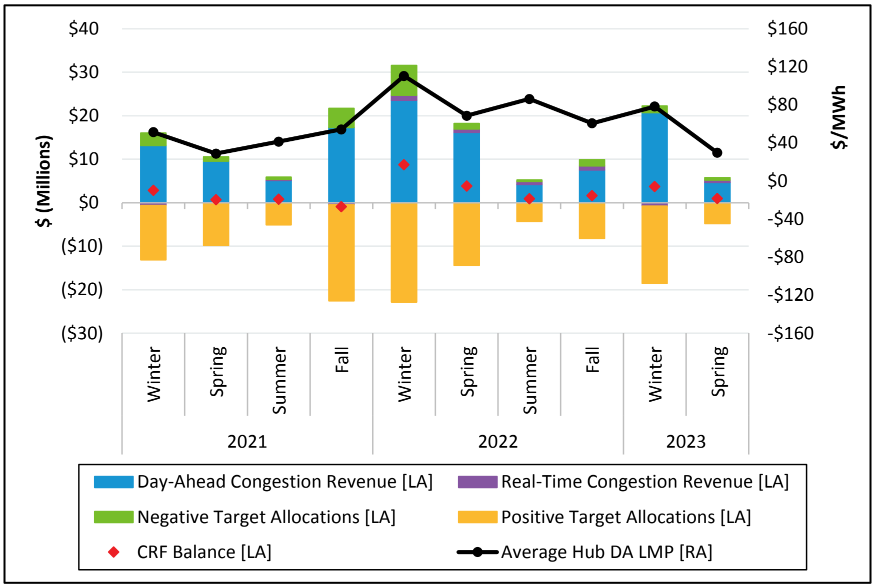
1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
3) the revenue associated with transmission congestion in the real-time market.

Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and Real-Time Energy Markets, the amount of positive and negative target allocations, and the

[41] The Net ICR is recalculated with the most up-to-date data for each annual reconfiguration auction leading up to the start of the capacity commitment period. All historical Net ICR values can be found here: https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx

congestion revenue fund (CRF) balance.[42] This figure also depicts the quarterly average day-ahead Hub LMP.[43]

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



Lower day-ahead prices contributed to lower day-ahead congestion revenue and target allocation values in Spring 2023.[44] Day-ahead congestion revenue amounted to $4.7 million in Spring 2023. This represents a decrease of 77% relative to Winter 2023 ($20.7 million) and a decrease of 71% relative to Spring 2022 ($16.2 million). Positive target allocations in Spring 2023 ($4.8 million) followed a similar pattern, decreasing by 73% relative to Winter 2023 ($17.7 million) and decreasing by 67% from Spring 2022 ($14.4 million). Negative target allocations in Spring 2023 (-$0.6 million) also decreased; by 63% from their Winter 2023 level (-$1.5 million) and by 55% from their Spring 2022 level (-$1.3 million). Meanwhile, real-time congestion revenue in Spring 2023 ($0.5 million) remained relatively modest and was generally in line with recent historical levels.

FTRs were fully funded in March 2023, April 2023, and May 2023.[45] At the end of May 2023, the congestion revenue fund had a surplus of $3.8 million.

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

[43] The average annual day-ahead Hub LMP is measured on the right axis ("RA"), while all the other values are measured on the left axis ("LA").

[44] 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.

[45] FTRs are said to be "fully funded" when there is 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.

5.3 Forward Reserve Market

In this section, we review the Summer 2023 Forward Reserve Auction (FRA) and present a recommendation that the offer cap for the FRA should be reduced to reflect current market and system conditions.

Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the Real-Time Energy Market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2023, the ISO held the forward reserve auction for the Summer 2023 delivery period (i.e., June 1, 2023 to September 30, 2023).[46]

5.3.1 Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability in the Real-Time Energy Market, based on possible system and local reserve zone contingencies (i.e., unexpected events, such as the forced outage of a large generator or loss of a large transmission line).

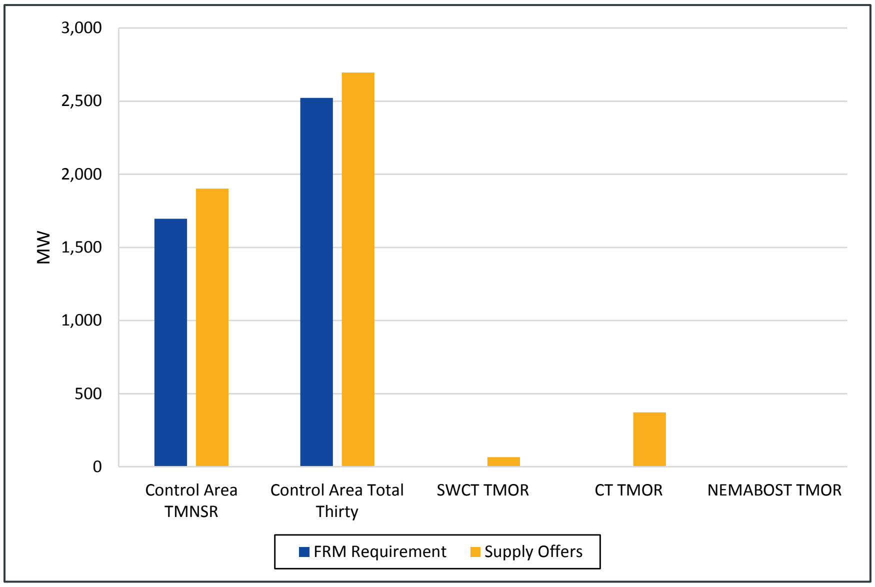
The requirements for the Summer 2023 auction are illustrated in Figure 5-3 below. These requirements were specified for the ISO New England system and three local reserve zones.[47] The figure also illustrates the total quantity of supply offers available to satisfy the reserve needs in the auction.[48]

[46] The Forward Reserve Market has two delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

[47] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[48] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. The system-level total thirty reserve data show all FRM supply offers in the auction, relative to the combined ten-minute non-spinning reserve (TMNSR) and TMOR system requirements. Finally, because TMNSR supply can contribute to TMOR supply, all TMOR totals in the graph show TMNSR in addition to TMOR supply.

Figure 5-3: Forward Reserve Requirements and Supply Offer Quantities



Two reserve products had system requirements in the auction: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,696 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Mystic 8 and 9 generators, and was estimated as an 826 MW TMOR need.[49] The total thirty-minute requirement (depicted in the figure) is the sum of the TMNSR and incremental TMOR requirements (i.e., 1,696 MW + 826 MW).[50] Offered reserve supply was adequate to satisfy requirements for both system-level products.

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which can also effectively supply reserves to the local area).[51] After adjustments, all local reserve zones – Connecticut, Southwest Connecticut and NEMA/Boston – were found to need no local reserve requirement, as "external reserve support" (i.e., available transmission capacity) exceeded the local second contingency requirements.

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[49] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2023 Forward Reserve Auction), published March 16, 2023, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement. See: https://www.iso-ne.com/static-assets/documents/2023/03/forward_reserve_auction_assumptions_summer_2023.pdf

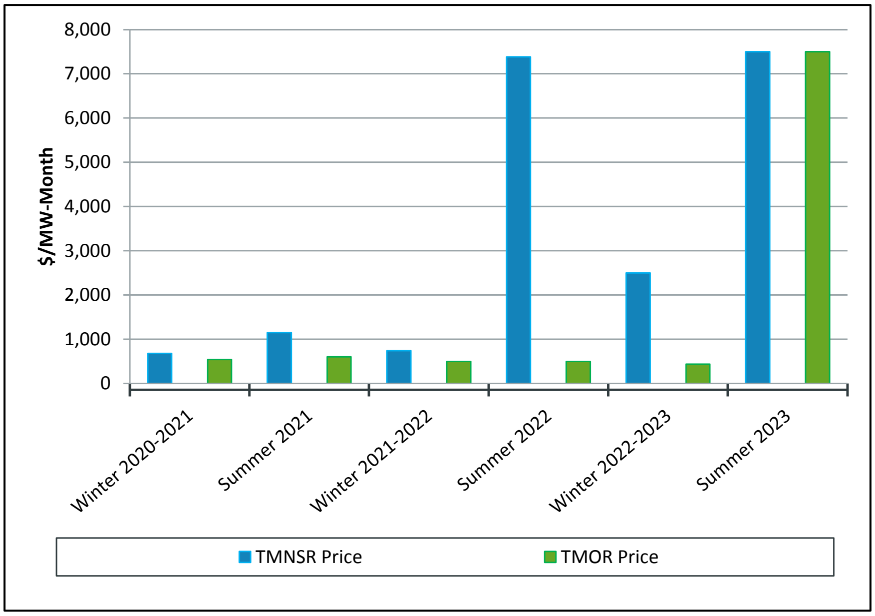
[50] The system TMOR requirement indicated in the ISO's auction assumptions represents an incremental requirement, in excess of the TMNSR requirement. The total thirty minute requirement for the auction is the sum of the TMNSR requirement and the system (incremental) TMOR requirement.

[51] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5).

5.3.2 Auction Results

Forward reserve clearing prices for the system-wide TMNSR and TMOR products for the previous six auctions are shown in Figure 5-4 below.

Figure 5-4: FRM Clearing Prices for System-Wide TMNSR and TMOR



The clearing prices for the Summer 2023 auction were substantially higher than for all of the other auctions in the review period, except for the Summer 2022 auction. TMNSR and TMOR each cleared at a price of $7,499/MW-month in the Summer 2023 auction. This compares with clearing prices of $2,500/MW-month (TMNSR) and $439/MW-month (TMOR) in the Winter 2022-2023 auction and clearing prices of $7,386/MW-month (TMNSR) and $499/MW-month (TMOR) in the Summer 2022 auction.

Several factors contributed to the increase in TMNSR auction clearing prices between the Winter 2022-2023 and the Summer 2023 auctions including:

1. a more than 300 MW increase in the TMNSR requirement,
2. a decrease of approximately 200 MW in TMNSR supply offers, and
3. an increase in participant offer prices in the summer auction. For these auctions, the TMOR clearing price also increased significantly because incremental TMOR supply offers were insufficient to satisfy the incremental TMOR requirement. This meant that relatively high-priced TMNSR supply was needed to satisfy the auction's total thirty reserve requirement; as a result, the total thirty supply cleared the auction at the same price as the TMNSR supply.[52]

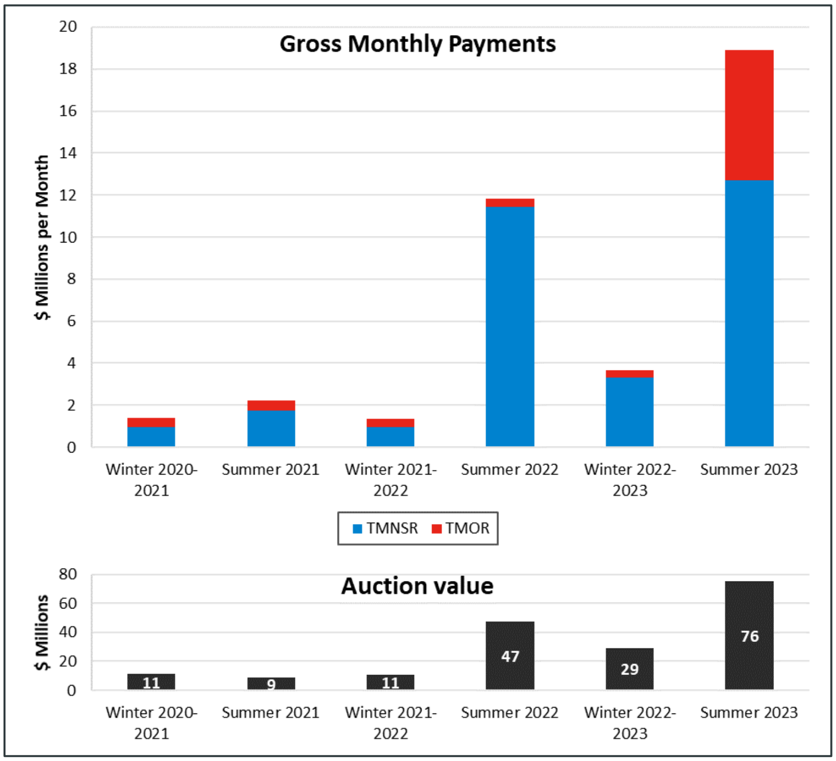
[52] Note that TMNSR supply will be substituted for TMOR supply when available TMNSR supply not needed to satisfy the TMNSR requirement has a lower offer price than available TMOR supply or when TMOR supply is insufficient to satisfy the incremental TMOR constraint. The TMNSR supply that clears to meet the TMNSR requirement effectively reduces the total thirty requirement to the incremental TMOR requirement (i.e., 826 MW).

The Summer 2023 and Summer 2022 auctions resulted in comparable clearing prices for the TMNSR product, with auction pricing of $7,499/MW-month in the Summer 2023 auction and $7,386/MW-month in the Summer 2022 auction. For Summer 2023, the TMNSR requirement and quantity offered each were approximately 100 MW higher than in the Summer 2022 auction; however, the substitution of TMNSR for TMOR supply to satisfy the total thirty reserve constraint resulted in a slightly higher clearing price ($7,499/MW-month) for TMNSR in the Summer 2023 auction.

TMOR prices increased significantly between the Summer 2022 and Summer 2023 auctions. The Summer 2023 auction had slightly less TMOR supply (approximately 130 MW) and a small increase in the incremental TMOR requirement.

The increase in clearing prices for the Summer 2023 auction also raises expected gross FRM payments for the Summer 2023 delivery period. Figure 5-5 indicates the monthly gross payments (i.e., excluding penalties) available to participants with TMNSR and TMOR FRM obligations for the six most recent FRM delivery periods and the value of each auction.

Figure 5-5: Gross Monthly FRM Payments and Auction Value



While gross monthly payments for auctions preceding Summer 2022 ranged from $1.4 to $2.2 million per month, the elevated clearing prices for the Summer 2022 and 2023 auctions significantly increased FRM payments. The Summer 2022 auction had gross payments of approximately $11.8 million per month. Gross payments declined with the reduced TMNSR pricing for the Winter 2022-2023 auction, falling to $3.8 million per month; however, the Summer 2023 auction, with elevated TMNSR and TMOR pricing, resulted in gross payments of approximately $18.9 million per month.[53]

5.3.3 Auction Competitiveness and IMM Recommendations

We are concerned that the forward reserve auctions, which have been structurally uncompetitive in the five most-recent summer auctions, are susceptible to participants exercising market power. Clearing prices for TMNSR in the two most-recent auctions are more than three times the highest clearing price observed for that reserve product during summer auctions between 2017 and 2021.

The results of the just-completed summer auction indicate that participants may have cleared offers in the auction that substantially deviated from cost-based competitive levels. As a result, we surveyed participants to understand how they constructed their offers for this auction. The responses generally failed to provide adequate support that could justify such high offers. We are concerned that the relatively high forward reserve supply offers indicate an awareness that the structurally-uncompetitive auctions provide an opportunity to submit uncompetitive supply offers.

While the ISO expects to terminate the forward reserve market with the implementation of the Day-ahead Ancillary Services Initiative in March 2025, the exercise of market power in the remaining auctions could result in a significant and inappropriate transfer of value from New England consumers to participants with FRM resources.

To limit the potential exercise of market power, the forward reserve auctions utilize a price cap (i.e., an upper bound on reasonably competitive supply offer prices); the ISO last updated the price cap in 2016. Our review suggests that the current price cap substantially overstates a reasonable upper bound on competitive forward reserve supply offers. The current price cap equals $9,000/MW-month; we estimate a more reasonable upper bound value of approximately $6,600/MW-month. Consequently, we recommend that the ISO review and update the forward reserve supply offer cap.

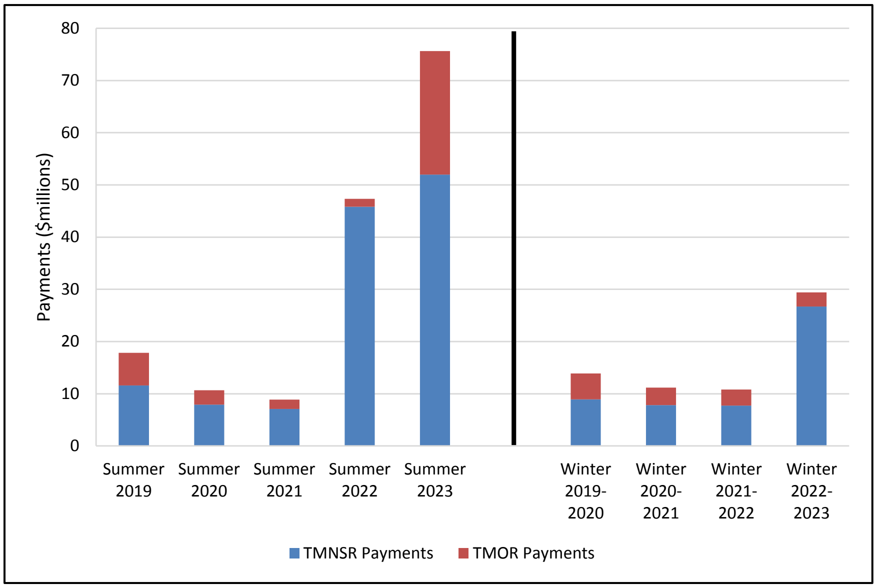
We outline our concerns with the forward reserve auctions in more detail below.

FRM Gross Payments

Figure 5-6 summarizes FRM gross payment data over the past nine auctions. It is clear that there has been a significant jump in TMNSR payments in both the winter and summer auctions since the Summer 2022 auction. This increase is a result of higher auction clearing prices for TMNSR, which were driven by relatively higher participant offers than observed in prior auctions.

[53] The gross payments are a function of both the clearing prices and the quantities cleared for each FRM product (i.e., TMNSR and TMOR) in each auction.

Figure 5-6: FRM Gross Payments



The TMOR clearing price was also elevated in the Summer 2023 auction because of substitution of TMNSR supply for TMOR supply. Relative to the 2019 summer auction, total TMOR payments for the Summer 2023 auction increased by $17 million.

IMM's Review of Forward Reserve Auctions and the Price Cap

The IMM monitors the performance and competitiveness of FRM auctions, but we do not have the authority to perform cost-based offer reviews and to mitigate uncompetitive offers in advance of the auction. A Tariff-specified offer cap for FRM auctions serves as the only constraint on potentially-uncompetitive offers in the auctions. Participants in forward reserve auctions may offer supply at prices up to the offer price cap; the auction determines clearing prices based on participant offers,[54] except when there is insufficient supply to meet the ISO's TMNSR or TMOR requirement. Insufficient supply for a reserve product will result in that product being assigned a clearing price equal to the offer price cap.[55]

The offer cap has a two-fold purpose: to limit the potential exercise of market power in an auction *while* not constraining participants from making cost-based competitive offers. The FRM offer cap is based on an expectation of a reasonable upper-limit on the bid-in cost for a hypothetical forward reserve resource.

FRM Auction Competitiveness and Pricing Trends

The Residual Supply Index's (RSI) measurement of structural competitiveness of the TMNSR and TMOR products with the clearing prices for each in recent forward reserve auctions are summarized in

[54] The ISO selects the least-cost cohort of supply offers to satisfy forward reserve requirements, based on participant offer pricing.

[55] TMNSR supply can be substituted for TMOR supply in the FRM auction, since TMNSR is a higher-quality reserve product.

Table 5-2 below. It utilizes a heat map to indicate auctions that were structurally uncompetitive (i.e., red shading for RSI < 100, indicating the existence of one or more pivotal suppliers).[56]

Table 5-2: FRM Auctions, RSI and Clearing Prices for TMNSR

Procurement Period	Offer RSI TMNSR	TMNSR Auction Clearing Price	Offer RSI Total Thirty	TMOR Auction Clearing Price
Summer 2018	112	$1,780	108	$1,780
Summer 2019	90	$1,899	97	$1,899
Summer 2020	84	$1,249	97	$900
Summer 2021	92	$1,150	108	$600
Summer 2022	78	$7,386	90	$499
Summer 2023	81	$7,499	86	$7,499
Winter 2018-19	127	$800	127	$750
Winter 2019-20	120	$799	118	$799
Winter 2020-21	102	$678	115	$540
Winter 2021-22	110	$740	116	$499
Winter 2022-23	109	$2,500	112	$439

For the TMOR (total thirty) forward reserve product, structurally-uncompetitive summer auctions have occurred during four of the prior six summer auctions. However, except for Summer 2023, the TMOR clearing prices have been relatively stable or declining. In the Summer 2023 auction, TMOR supply was inadequate to meet the incremental TMOR requirement, and TMNSR supply had to be substituted to meet that requirement.

For TMNSR, all but one of the recent summer-period forward reserve auctions for the TMNSR product have been structurally uncompetitive. Up to the Summer 2022 and Summer 2023 auctions, we observed relatively stable, or declining prices, for the TMNSR product in the summer auctions. That result suggested a reduced risk of the potential exercise of market power, despite the lack of structural competitiveness. The Summer 2022 auction, however, resulted in a pricing outcome for TMNSR that was significantly higher than in the preceding auctions.

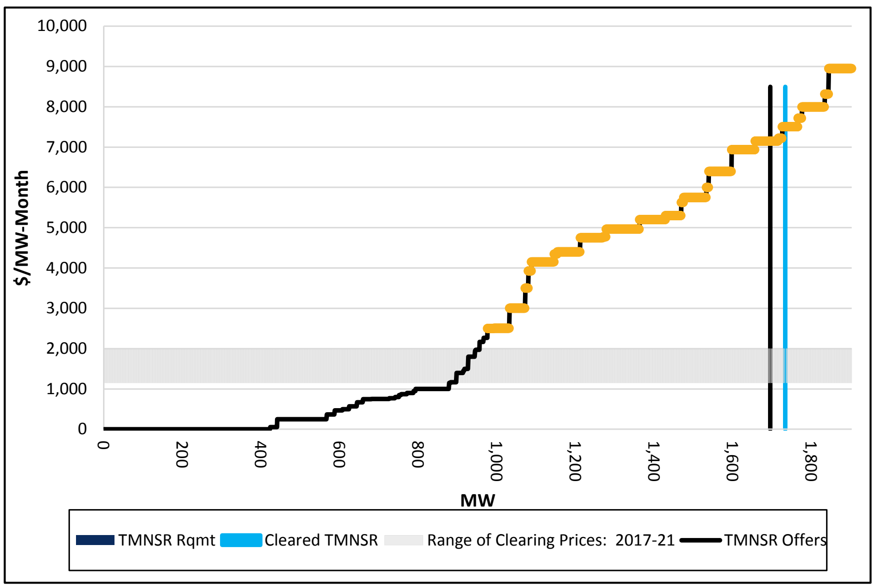
The Summer 2022 auction had elevated TMNSR offer pricing compared to earlier auctions; some of the offers were considerably higher than in earlier auctions. We requested participant documentation for increased offer pricing. The documentation indicated certain risks and costs that provided an adequate justification for the increase in offer prices. Given the documentation and the relatively high offer price cap for forward reserve auctions, we could not conclude that the participant's offers were unreasonable.

[56] The RSI values indicate the supply that is available to meet the FRM TMNSR requirement, when the supply of the largest supplier is not available. The RSI is stated as a percent of the requirement: for example in Summer 2023, supply – after excluding the largest supplier – could meet only 81% of the TMNSR requirement. When the RSI is less than 100, it suggests that the largest supplier, and potentially other suppliers with strategic information, may be able to exercise market power in the auction.

However, in the Summer 2023 auction, multiple participants offered TMNSR supply at significantly elevated prices, compared to pre-2022 auctions. Coupled with a somewhat higher summer auction TMNSR requirement, the upward shift in the TMNSR supply curve resulted in a high clearing price.[57] After reviewing and assessing the results of the most recent auction the IMM cannot conclude that prices were the result of competitive offers. This assessment was informed by both a top-down assessment of a range of competitive bids as well as an outreach to a number of participants in the auction.

Figure 5-7 provides the TMNSR supply curve for the 2023 auction, with the yellow-colored dots indicating the location of the high-priced participants' offers. (Participants with offers exceeding $2,400/MW-month are highlighted in the figure. These are offers that exceed prior auction clearing prices (2017-2021) by at least 20 percent.) The gray horizontal band indicates the clearing prices for TMNSR in the summer auctions occurring for 2017 to 2021.[58]

Figure 5-7: TMNSR Supply Curve, Summer 2023 Auction



As we stated previously, we are concerned that the increase in the number of participants with relatively high forward reserve supply offers may indicate an awareness that the structurally-uncompetitive auctions provide an opportunity to submit uncompetitive supply offers. Competitive offers in the forward reserve auctions should reflect reasonable expectations about future real-time reserve revenues and performance risks (and costs) associated with carrying a forward reserve obligation. We are unaware of material energy and ancillary service market changes that would result in the elevated forward reserve offers across multiple participants for the 2023 summer auction.

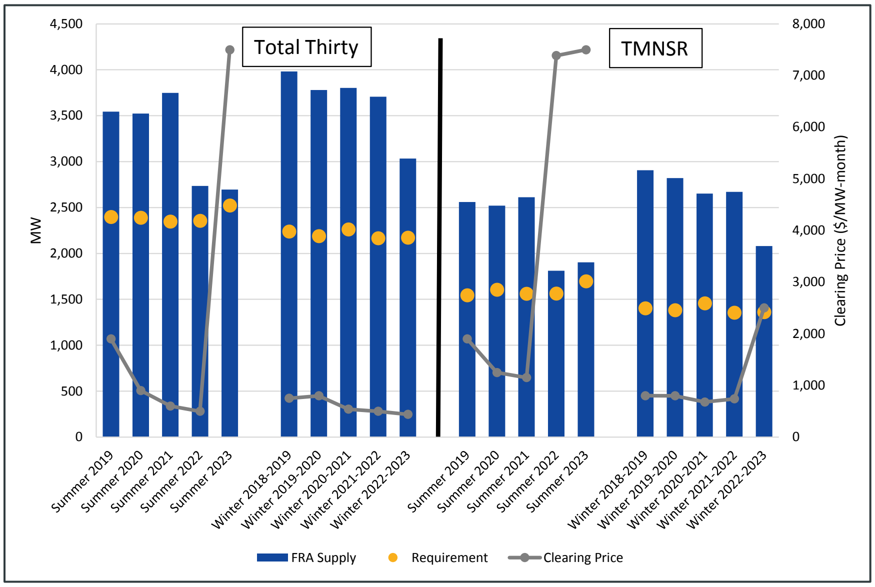
Based on observed participation levels illustrated in Figure 5-8, we have concerns that more supply will not enter the auction in response to high prices and alleviate the market power issues. We have observed declining supply for the total thirty and TMNSR products in the forward reserve auctions.

[57] The TMNSR requirement in the summer auctions has varied between 1,435 and 1,696 MW between 2017 and 2023.

[58] Note that the TMNSR product cleared more supply than its requirement, because it was economic to substitute TMNSR supply for TMOR in clearing the auction's overall reserve requirement.

The exception is a small increase in TMNSR supply for the Summer 2023 auction, a 5% increase compared to the Summer 2022 auction. We remain concerned that TMNSR supply will not return to 2021 levels for future auctions and opportunities to exercise market power in those auctions will persist.

Figure 5-8: Forward Reserve Auction Supply, Requirements, and Clearing Prices



FRM Offer Price Cap Review

As noted earlier, we do not have the authority to perform ex-ante, cost-based reviews of FRM auction supply offers and to mitigate uncompetitive offers. Without the data from such a review, the basis of offer prices is non-transparent. The auctions assign forward reserve obligations to participants and not to individual resources. After a participant obtains an obligation, it is free to assign that obligation to various resources in its portfolio when the obligation is delivered in the Real-Time Energy Market. Additionally, the quantity of forward reserve obligation obtained by a participant may increase its performance risks and costs. These factors both affect offer pricing and potentially complicate an ex-ante or ex-post review of supply offers. However, lacking a detailed pre-auction review of supply offers and limited data from our outreach to participants after the auction, we cannot conclude that an auction's offer pricing is competitive.

Given that limitation, the FRM offer price cap provides an important safeguard for limiting the exercise of market power within forward reserve auctions. We reviewed the current offer cap, which was last updated in 2016[59], and concluded that the current offer cap of $9,000/MW-month significantly overstates a reasonable upper bound on competitive offers. Our analysis indicates that a revised cap of $6,600/MW-month is a more reasonable reflection of the upper bound of competitive offers. The derivation of the offer cap is discussed in detail below.

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59 ISO New England filing to the Federal Energy Regulatory Commission, February 10, 2016 (ER16-921-000). See: https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf

Offer Cap Components

As outlined in the ISO's 2016 filing[60] to revise the FRM offer price cap, the offer cap should be set to limit the potential exercise of market power, while not unduly restricting competitive offers. This requires that the offer price cap represent a reasonable upper bound on a competitive supply offer. Since the offer cap is both fixed and an expectation of a reasonably-competitive offer, a "conservative" estimate is needed to accommodate unexpected energy market conditions that may occur and have a significant impact on operating reserve revenues (such as capacity scarcity conditions). Being conservative in setting the offer price cap likely will result in the cap overstating, to some degree, a reasonably competitive offer. However, a cap that is too restrictive could limit forward reserve auction supply offers, if expected energy market conditions materially change.

The current offer price cap utilized a defined framework for determining an upper bound for a reasonably competitive forward reserve supply offer. Our review and updating of the offer price cap utilizes this framework. The framework consists of several elements:

- expected reserve revenue,
- foregone energy market revenue,[61]
- risk of incurring forward reserve market penalties,[62]
- risk premium for accepting the forward reserve obligation.

Table 5-3 provides a comparison of the current supply offer cap's individual pricing components with our recommended revisions.

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[60] ISO New England filing to the Federal Energy Regulatory Commission, February 10, 2016 (er16-921-000). See: https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf

[61] Energy market supply offers with FRM obligations must offer at or above a specified threshold price. The threshold price is set administratively at a high price, to limit the dispatch of FRM resources in the energy market.

[62] FRM resources may incur two types of penalties: failure to reserve and failure to activate. Failure to reserve penalties apply when a participant fails to assign and deliver its FRM obligation in the energy market. Failure to activate occurs when a resource that has been assigned an FRM obligation fails to come on-line, when committed and dispatched by the ISO.

Table 5-3: FRM Supply Offer Price Cap Components

Line	Reserve Revenue	Current	Proposed
a	Capacity Excess/Shortfall (As of FCA 15 ARA 1)	n/a	2,200
b	75th percentile CSC Hours (approx)	25.12	2.30
c	Transient & Winter Adjustment Hours	n/a	0.27
d	Season %	0.51	1.00
e	CSC Hours (=(b+c)*d)	12.81	2.57
f	Summer Months	4.00	4.00
g	CSC Hours/Month (=e/f)	3.20	0.64
h	Payment Rate	1,075	1,616
i	CSC Hour Reserve Revenue ($/MW-mo) (=g*h)	3,443	1,038
j	Non-CSC Reserve Revenue	1,500	1,142
k	**Total Reserve Revenue ($/MW-mo) (=i+j)**	**4,943**	**2,180**
	Non-Reserve Offer Cap Components		
l	Foregone Energy Market Revenue	700	2,091
m	Failure to Activate Penalty	50	50
n	Failure to Reserve Penalty (=(k+l+m)*0.33)	1,896	1,426
o	Risk Premium (=(k+l+m+n)*0.15)	1,138	862
p	Total ($/MW-mo) (=k+l+m+n+o)	8,727	6,609
q	**Offer Cap ($/MW-mo) (rounded)**	**≈ 9,000**	**≈ 6,600**

Reserve Revenue

Reserve revenue constitutes a significant portion of the offer cap estimates. The reserve revenue reflects an expectation of the Real-Time Energy Market reserve revenue that will be available during the forward reserve delivery period.[63] The reserve revenue has two components: revenue during capacity scarcity condition (CSC) or Pay-for-Performance (PFP) periods and non-scarcity periods.

For the CSC estimates, the ISO previously assumed that there would be 25.12 CSC hours per year; these are periods during which operating reserve pricing is based on a reserve constraint penalty factor for TMNSR or TMOR. In actuality, CSC periods have been very rare, totaling just 4.6 hours since "Pay-for-Performance" was implemented in June 2018.

In the ISO's earlier estimate, it used a summer CSC hour estimate in setting the FRM cap, since the summer was likely to have more CSC hours than the winter.[64] The ISO's estimate for summer CSC hours was 12.8 hours. Our updated estimate yields 2.6 expected CSC hours during the summer period.[65] Converting the summer value into a monthly value (i.e., summer CSC hours / four

[63] In the FRM, a participant collects the forward reserve clearing price in lieu of collecting real-time energy market reserve revenues, during the FRM's delivery period. The delivery period is on-peak hours during non-holiday weekdays.

[64] In the ISO's 2016 estimate, it converted the annual CSC hours to a summer equivalent based on its view that approximately half (i.e., 51%) of the annual hours would occur during the four summer months (June to September).

[65] CSC hours indicate scarcity conditions during high load hours; the ISO expects very few of these hours to occur during the winter and shoulder periods. The transient adjustment hours reflect instances when other types of system conditions may result in scarcity hours, e.g., under-commitment resulting from load forecast errors, loss of critical transmission elements, and

months), we estimate 0.6 hours of CSC conditions per month, compared to the 3.2 CSC hours per month assumed in the current cap estimates.[66] To estimate reserve revenue from the hours, we utilize the average actual revenue per CSC hour, which is $1,616/MWh (i.e., a simple average of the TMNSR prices observed during the 3.2 actual CSC hours during the summer period). The ISO previously assumed that CSC pricing would average $1,075/MWh. Combining the CSC hours and reserve payment rate assumptions results in expected CSC compensation of $1,038/MW-month for the updated estimate. This compares with $3,443/MW-month in the ISO's 2016 offer cap estimates.

For the non-CSC hour operating reserve revenue, we reviewed historical data for the summer months from June 2017 through early-July 2023. We estimated the TMNSR/TMOR revenue available in each month for one MW of operating reserves.[67] TMNSR and TMOR pricing have occurred relatively infrequently in the ISO's energy markets. All but three of the summer months had TMNSR/TMOR revenue less than $1,000/MW-month. Summer reserve revenue from 2017 to 2023 averaged just $422.5/MW-month, with 90% of all observations equal to or less than $1,142/MW-month. The ISO's 2016 estimate was $1,500/MW-month. We propose using the 90th percentile value (i.e.,$1,142/MW-month) for the revised offer cap. We also reviewed reserve pricing for the winter months. There was considerably less reserve revenue in those months for TMNSR and TMOR, with mean monthly revenue of $110/MW-month and 90% of all observations equal to or less than $244/MW-month.

Foregone Energy Market Revenue

To update the estimate of foregone energy market revenue for an FRM resource, we utilized revenue estimates for actual, relatively fuel-efficient, dual-fuel peaking resources in New England.[68] We compared estimates for the generators' energy market LMP revenue, assuming no FRM obligation and an FRM obligation. The reduction in revenue between no-FRM dispatch and FRM dispatch provided our energy market foregone revenue estimate.

Our estimates cover the summer months for the most recent four-year period. The average lost revenue for our estimates is approximately $867/MW-month; 90% of the monthly observations are equal to or less than $2,091/MW-month. The 90th percentile value appears to be a reasonable upper bound on foregone energy market revenue. We note that it represents a conservative estimate that relies on lower-cost peaking resources that are more likely to incur energy market opportunity costs than older resources with higher operating costs and fewer energy market dispatch

other factors. See: https://www.iso-ne.com/static-assets/documents/2020/07/a5_a_presentation_scarcity_hours_balancing_ratio.pptx

[66] The IMM's estimate utilizes the ISO's CSC hour estimates for FCA 15 (capacity commitment period 2024-2025). See: https://www.iso-ne.com/static-assets/documents/2020/12/a00_pspc_2020_12_iso_memo_or_def_fca_15.pdf
The annual CSC hour estimates are based on the expected amount of capacity surplus available to the energy market and the 75th percentile of observations. For example, with an approximately 2,200 MW capacity surplus, 75% of the observations are at 2.3 hours or less. As noted in the ISO's original filing, the 75th percentile was chosen because it appeared to be a conservative, reasonable upper bound. Using the 75th percentile as an upper bound provides reasonable accommodation for varying market conditions and participant expectations.

[67] Because TMNSR is a higher-quality reserve product than TMOR, TMNSR also receives TMOR pricing. Hence, TMNSR pricing incorporates all relevant TMOR pricing data.

[68] The revenue estimates are net of short-run variable costs.

opportunities.[69] Our updated estimate of $2,091/MW-month compares to the ISO's 2016 estimate of $700/MW-month.

Failure to Activate Penalties

An FRM resource incurs failure to activate penalties when it fails to come on-line when requested to do so by the ISO. Failure to activate penalties have represented approximately 0.1% of gross FRM payments over the last five years, and have not exceeded 0.5% during any of those years. We recommend that the 2016 estimate of $50/MW-month be maintained in the updated offer cap. That value represents approximately 0.8% of the proposed offer cap, and provides sufficient accommodation for poor performance by potential FRM resources.

Failure to Reserve Penalties

An FRM resource incurs these penalties when a participant with an FRM obligation fails to assign the obligation to specific resources or fails to offer its FRM resources in the real-time energy at (or above) the FRM strike price. In its 2016 updating of the FRM offer cap, the ISO discussed the difficulty of estimating failure to reserve penalties. This difficulty occurs because the penalty is dependent on the FRM auction clearing prices, since the penalty requires the return of FRM payments. The ISO performed an analysis to derive this value for the 2016 updating; it found that a stable penalty rate for the offer cap equaled an increase in the offer cap of approximately one-third (i.e., the penalty rate = (reserve revenue + energy market revenue + failure to active penalties) x 1/3). We recommend that this failure to reserve penalty rate of 1/3 be maintained in the updated offer cap.

Risk Premium

Finally, the offer cap includes a risk premium adjustment to compensate participants with FRM obligations for the risks associated with holding the forward obligation. These risks result from the uncertainty associated with estimating the needed revenues for acquiring the obligation (i.e., the risk of underestimating real-time reserve revenue, foregone energy market opportunities, generator availability, etc.). The ISO's earlier estimate of a 15% risk adder has been adopted for the recommended offer cap updating.

Overall Offer Cap Update

Based on the ISO's 2016 framework for developing a reasonable offer cap, we find that the FRM offer cap should be substantially reduced. The reduction occurs primarily from updates to the reserve revenue components of the framework. Since both the failure to reserve penalties and risk premium are stated as a percentage of other cap components, those two elements of the offer cap are also reduced by the updated reserve revenue estimates. Overall, the recommended changes in the offer cap would reduce it from approximately $9,000/MW-month to $6,600/MW-month.

[69] Additionally, our estimates overstate the combination of reserve and energy market revenue available to fast-start resources. The reserve revenue estimates assume that reserve resources are off-line and available during every reserve pricing interval within a month. For a fast-start resource operating during intervals with reserve pricing, the energy market LMP will account for (implicitly include) reserve market prices in almost every instance. We have not adjusted energy market revenue to account for dispatch intervals with positive reserve prices, and hence overstate available revenues for FRM resources.

Publication of Offer Data

Given the frequency of structurally-uncompetitive forward reserve auctions and elevated offer pricing in the summer 2023 auction, we are concerned that the publication of auction offer data may provide strategic information to participants in the auctions. We recommend that the ISO cease the publication of auction offer data or delay publication until several auction cycles have passed. While we generally support transparency regarding the ISO's markets, the availability of prior participant offer data (even masked) that shows offer quantities and prices, when combined with current auction information such as the requirements for TMNSR and TMOR, may enable uncompetitive offers in an auction.