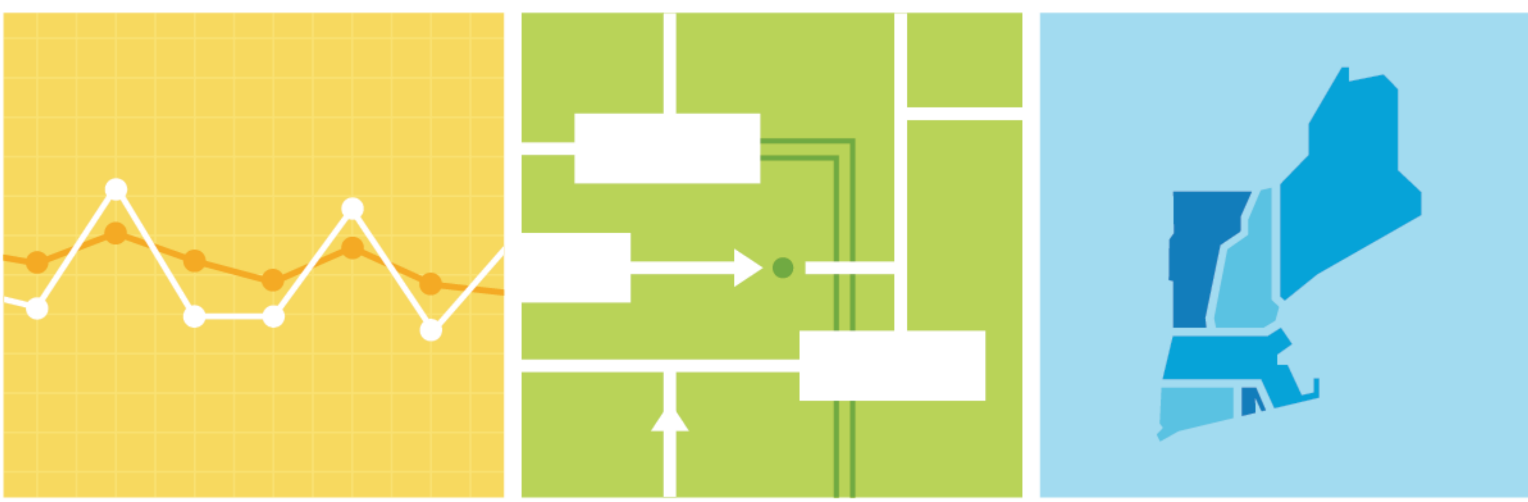
Fall 2022
Quarterly Markets Report

By ISO New England's Internal Market Monitor

JANUARY 31, 2023



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Preface

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

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

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

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

Underlying natural gas data furnished by:

ice Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Fall 2022 (September 1, 2022 through November 30, 2022).

Wholesale Costs: The total estimated wholesale market cost of electricity was $2.39 billion, up 9% from $2.19 billion in Fall 2021. The small increase was driven by higher energy costs.

Energy costs totaled $1.85 billion; up 13% (or $211 million) from Fall 2021 costs. Increased energy costs were a result of higher natural gas prices. In Fall 2022, gas prices increased by 18% compared to Fall 2021.

Capacity costs totaled $501 million, down 6% (by $31 million) from last fall. 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. Last year, 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. Additionally, beginning in Summer 2022, the capacity figure includes supplemental payments to the Mystic 8 and 9 generators. These payments totaled $77.6 million in Fall 2022.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $60.58 and $60.28 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were both 12% higher than Fall 2021 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $6.00/MMBtu in Fall 2022, 18% higher than the Fall 2021 price of $5.07/MMBtu.
- There were fewer nuclear generator outages in Fall 2022 than in Fall 2021. Additionally, average and peak loads were lower compared to the previous fall, by 428 and 2,294 MW, respectively. These factors lessened the impact of higher natural gas prices on LMPs.
- Energy market prices did not differ significantly among load zones.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $8.6 million, an increase of 10% or $0.8 million compared to Fall 2021. NCPC remained relatively low and comprised just 0.5% of total energy payments in Fall 2022, slighlty less than the historical average over the reporting horizon of 0.7%.

The majority of NCPC (90%) was for first contingency protection, also known as “economic” NCPC. Fall 2022 economic NCPC payments increased by 27% or $1.6 million compared to Fall 2021 payments, consistent with the increase in energy payments. Most economic payments (71%) occurred in the real-time market. Out-of-merit payments continue to make up the majority of economic uplift, and increased from $4.0 million to $5.0 million between Fall 2021 and Fall 2022.

Real-time Reserves: Real-time reserve payments totaled $1.3 million, a $0.3 million decrease from $1.6 million in Fall 2021. Most payments (82%) were for ten-minute spinning reserve (TMSR).

The frequency of non-zero spinning reserve prices decreased from 351 hours to 206 hours due to lower spinning reserve requirements. However, the average non-zero spinning reserve price increased relative to Fall 2021, from $7.35 to $9.58/MWh. While the average TMNSR and TMOR prices in Fall 2022 were high ($158.74/MWh and $239.63/MWh, respectively), the occurrence of non-zero pricing for both products was less than one hour.

Regulation: Regulation market payments totaled $7.2 million, up 13% from $6.4 million in Fall 2021. This increase primarily reflected higher capacity prices and associated payments for regulation resources. The increase in capacity prices resulted from higher energy market opportunity costs (reflecting increased LMPs in Fall 2022). An increase in service prices and payments for Fall 2022 also contributed to the rise in regulation payments.

Financial Transmission Rights (FTRs): The two main drivers of congestion in Fall 2022 were: 1) transmission work in southwestern Connecticut; and 2) wind generation competing to export power over the limited local transmission network in eastern Maine. FTRs in September, October, and November 2022 were fully funded. Positive target allocations totaled $8.2 million in Fall 2022, down 63% from Fall 2021 ($22.1 million). Day-ahead congestion revenue also decreased in Fall 2022, totaling $7.5 million compared to $17.3 million in Fall 2021. Negative target allocations (-$1.4 million) were 68% lower than their Fall 2021 level (-$4.4 million). Real-time congestion revenue in Fall 2022 ($0.9 million) remained relatively modest and was generally in-line with recent historical levels. At the end of November, the 2022 congestion revenue fund surplus was $9.7 million, meaning more than sufficient revenue was generated to pay FTR holders.

Energy Market Competitiveness: The residual supply index for the real-time market in Fall 2022 was 104, indicating that, on average, the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier. There was at least one pivotal supplier present in the real-time market for 28% of five-minute pricing intervals in Fall 2022. This was slightly higher than the frequency of pivotal suppliers during the previous fall (24%). The increase was due to lower total 30-minute reserve margins, which decreased due to planned pumped-storage generator outages during Fall 2022.

Mitigation continued to occur very infrequently in the quarter. During Fall 2022, mitigation asset-hours represented a small fraction (0.08%) of total-asset hours. Very few reliability commitment mitigations occurred in Fall 2022, with just 10 asset-hours in the day-ahead market. Maine and Southeastern Massachusetts Rhode Island (SEMA-RI) have had the highest frequency of reliability commitment mitigations throughout the reporting period. This is consistent with transmission work that occurred in SEMA-RI and the frequency of localized transmission issues in Maine over the past two years. General threshold (pivotal supplier) mitigation and constrained area mitigation have had the lowest mitigation frequency at close to 0% over the review period.

Section 2
Overall Market Conditions

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

Table 2-1: High-level Market Statistics

Market Statistics	Fall 2022	Summer 2022	Fall 2022 vs Summer 2022 (% Change)	Fall 2021	Fall 2022 vs Fall 2021 (% Change)
Real-Time Load (GWh)	26,747	33,905	-21%	27,682	-3%
Peak Real-Time Load (MW)	17,741	24,787	-28%	20,035	-11%
Average Day-Ahead Hub LMP ($/MWh)	$60.58	$86.13	-30%	$54.18	12%
Average Real-Time Hub LMP ($/MWh)	$60.28	$86.28	-30%	$53.87	12%
Average Natural Gas Price ($/MMBtu)	$6.00	$7.81	-23%	$5.07	18%
Average No. 6 Oil Price ($/MMBtu)	$19.33	$23.53	-18%	$14.81	30%

To summarize the table above:

- Day-ahead LMPs averaged $60.58/MWh in Fall 2022, up 12% from Fall 2021 ($54.18/MWh). Higher gas prices in Fall 2022 ($6.00/MMBtu) compared to Fall 2021 ($5.07/MMBtu) put upward pressure on LMPs.
- The year-over-year increase in gas prices (18%) exceeded the increase in energy prices (12%) because Fall 2022 saw fewer baseload generator outages and lower loads than Fall 2021. The 23% decline in natural gas prices compared to Summer 2022 was driven by a decrease in natural gas demand.
- Total load in Fall 2022 (26,747 GWh, or an average of 12,247 MW per hour) was 3% lower than in Fall 2021 (27,682 GWh).

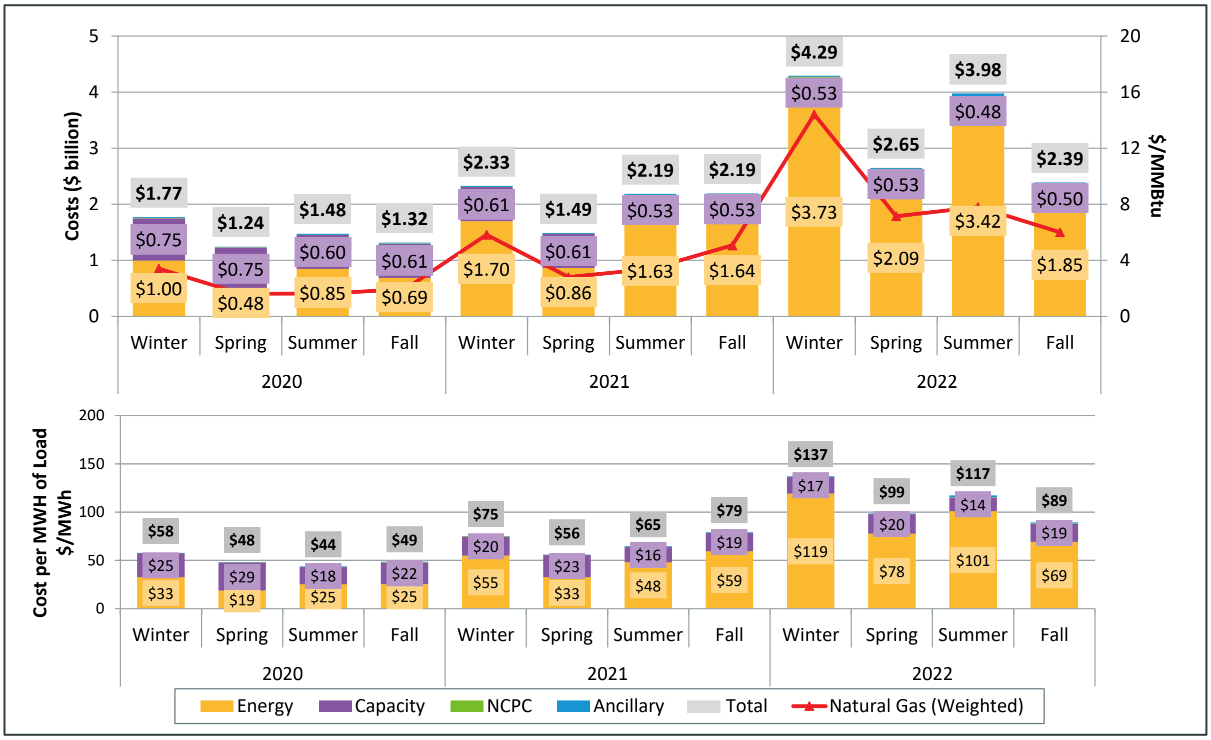
2.1 Wholesale Cost of Electricity

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.[3] The upper panel also shows the average price of natural gas price (in $/MMBtu) as energy market payments in New

[3] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

England tend to be correlated with the price of natural gas in the region.[4] 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



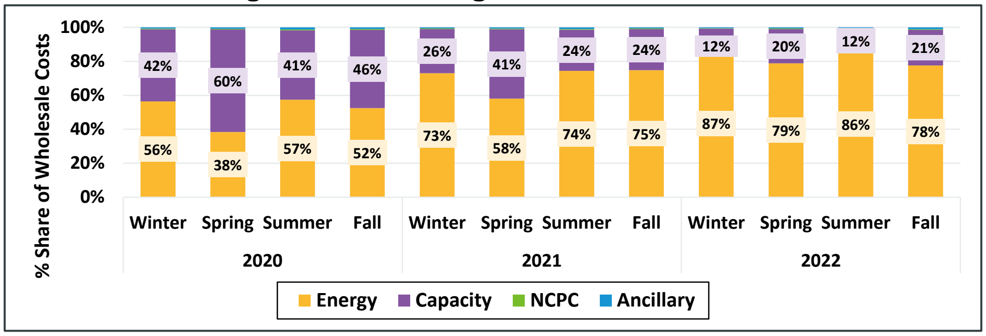
In Fall 2022, the total estimated wholesale cost of electricity was $2.39 billion (or $89/MWh of load), a 9% increase compared to $2.19 billion in Fall 2021 and a 40% decrease compared to the $3.98 billion in Summer 2022. The increase from Fall 2021 was driven by an increase in energy costs. The share of each wholesale cost component is shown in Figure 2-2 below.

Energy costs, which comprised 78% of the total wholesale cost, were $1.85 billion ($69/MWh) in Fall 2022, 13% higher than Fall 2021 costs, driven by a 18% increase in natural gas prices. Natural gas prices, which saw record lows in 2020 and record highs in 2021 and 2022, continued to be a key driver of energy prices. The Fall 2020 natural gas price ($1.93/MMBtu) was the lowest fall price since 2001, while the Fall 2022 natural gas price ($6.00/MMbtu) was the highest fall price since Fall 2008.

[4] 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 11 on D+2.

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 13), and totaled $501 million ($19/MWh), representing 21% of total wholesale energy costs. The current capacity commitment period (CCP13, 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. Additionally, beginning in Summer 2022, the capacity figure includes supplemental payments to the Mystic 8 and 9 generators.[5] These payments totaled $77.6 million in Fall 2022. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

Figure 2-2: Percentage Share of Wholesale Cost



At $8.6 million ($0.32/MWh), Fall 2022 Net Commitment Period Compensation (NCPC) costs represented 0.5% of total energy costs, slightly less than the historical average over the reporting horizon of 0.7%. In dollar terms, NCPC costs were $0.8 million (or 10%) higher than in Fall 2021, driven by an increase in first contingency payments.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $26.5 million ($0.99/MWh) in Fall 2022, representing 1% of total wholesale costs. Driven by higher forward reserve payments, ancillary service costs increased by 113% compared to Fall 2021 costs.[6] Compared to Summer 2022, Ancillary service costs were down by 51%.

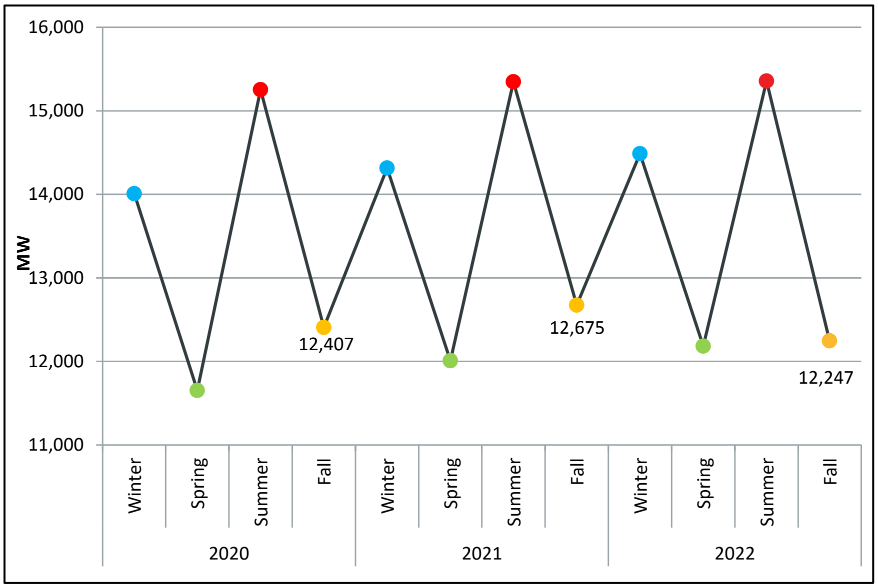
[5] Please note that the Wholesale Costs metric was updated in this report to include the supplemental capacity payments to the Mystic generators. Therefore, the Summer 2022 capacity payments presented in this report ($458m) differ from the figure in the Summer 2022 QMR ($423m).

[6] The IMM reviewed the 2022 Summer and Winter Forward Reserve Auctions in the 2022 Spring QMR and 2022 Summer QMR, respectively.

2.2 Load

In Fall 2022, average loads decreased 3.4% compared to Fall 2021 due to cooler weather during September. Additionally, growing behind-the-meter photovoltaic generation and energy efficiency continued to contribute to lower loads in every month.[7] 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



In Fall 2022, loads averaged 12,247 MW, a 3.4% (or 428 MW) decrease compared to Fall 2021 (12,675 MW) and a 1.3% (or 160 MW) decrease compared to Fall 2020 (12,407 MW). Average load fell year-over-year due to fewer Cooling Degree Days (CDDs), especially during the month of September.[8] Additionally, behind-the-meter photovoltaic generation increased by 58 MW (374 vs. 316 MW), contributing to lower wholesale load.

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). The top panel compares average monthly load

[7] 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).

[8] 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.

to monthly total CDDs. The bottom panel compares average monthly load to monthly total heating degree days (HDDs).[9]

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

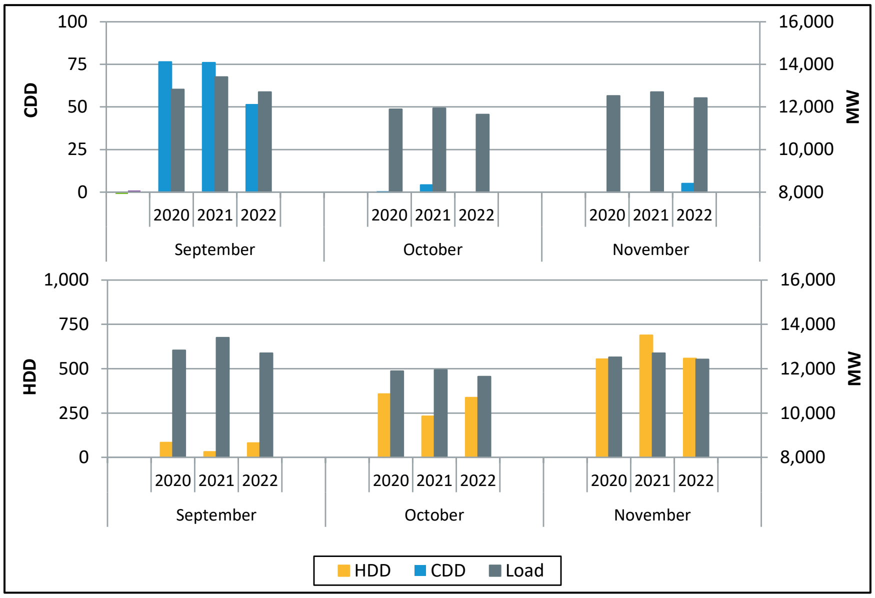


Figure 2-4 shows that average monthly load was lower year-over-year for all three months in Fall 2022. The largest monthly decrease in average load occurred in September 2022 (12,701 MW), when loads decreased by 705 MW compared to September 2021 (13,406 MW). Temperatures averaged 64°F in September 2022, a 3°F decrease from September 2021 (67°F), which led to fewer CDDs (51 vs. 76) and lower electricity demand for air-conditioning.[10] In October 2022 (11,644 MW) and November 2022 (12,415 MW), average loads decreased by 299 MW and 285 MW, respectively. During these two months, the total CDDs and HDDs were similar year-over-year, so weather likely had a small impact on differences in load. These decreases in average load are in line with growing energy efficiency and behind-the-meter photovoltaic generation in New England.

Peak Load and Load Duration Curves

New England's system load over the past three fall seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher. Fall 2022 is shown in red, while Fall 2021 is shown in black and Fall 2020 is shown in gray.

[9] 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] Changes in CDDs have a greater impact on load than changes in HDDs. Electricity demand responds more to changes air-conditioning demand than heating demand in New England.

Figure 2-5: Load Duration Curve

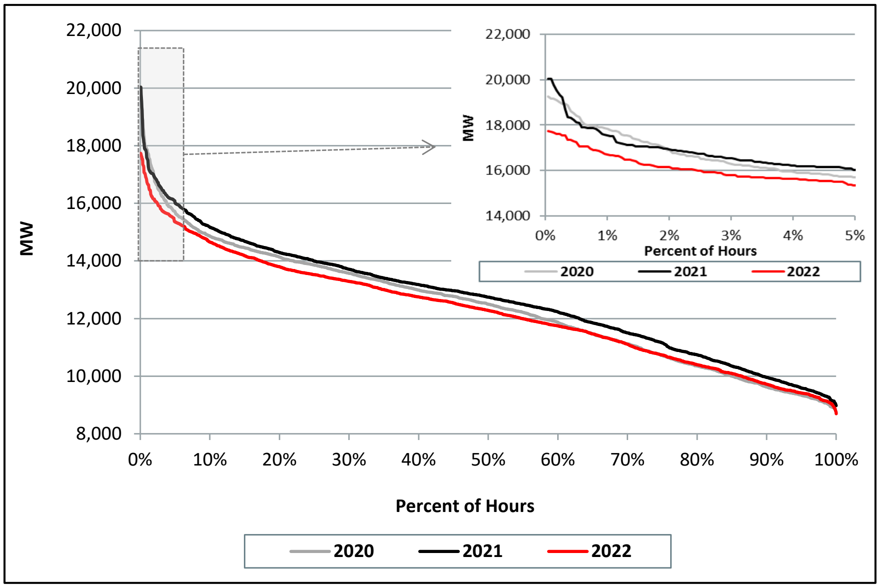


Figure 2-5 shows that loads in Fall 2022 were lower across all observations when compared to Fall 2021 and lower across more than 59% of observations when compared to Fall 2020. In Fall 2022, loads were higher than 14,000 MW in 17% of all hours compared to 25% and 22% in Fall 2021 and 2020, respectively. During the top 5% of hours (inset graph), Fall 2022 loads were below loads in Fall 2021 and Fall 2020, respectively. In Fall 2022, the load in the top 5% of all hours averaged 16,151 MW, which was 804 MW lower than the Fall 2021 average (16,954 MW) and 706 MW lower than the Fall 2020 average (16,857 MW). During the fall, peak loads are driven by warm days when air-conditioning demand causes higher wholesale load. Of the 20 warmest days over the prior three Septembers, only three occurred during September 2022. This compares to ten days and seven days in Fall 2021 and Fall 2020, respectively.

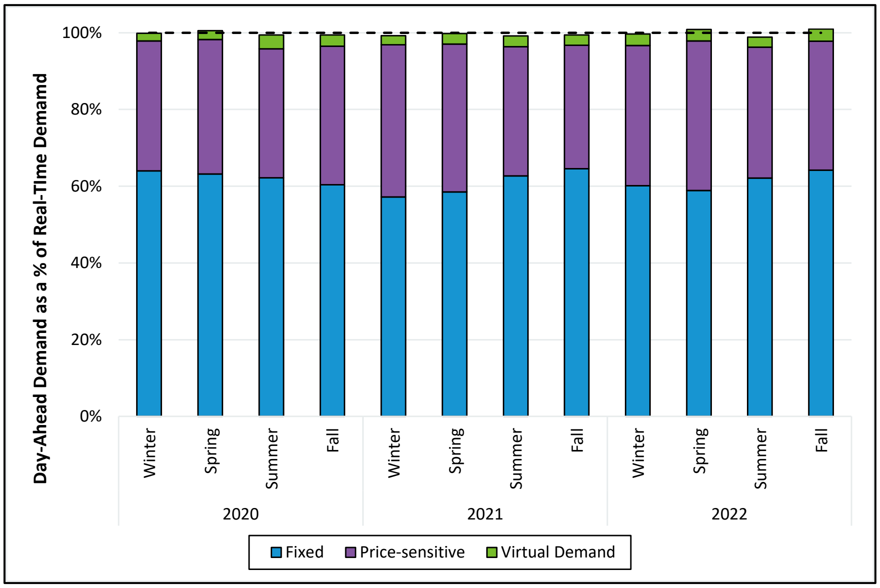
Load Clearing in the Day-Ahead Market

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.[11] 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 when additional commitments are needed subsequent to the day-ahead process. The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below. Day-ahead

[11] 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.

demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[12]

Figure 2-6: Day-Ahead Cleared Demand as a Percent of Real-Time Demand



In Fall 2022, participants cleared 101.0% of their real-time demand in the day-ahead market, which was up from 99.4% in both Fall 2021 and Fall 2020. The over-clearing of demand likely contributed to the slight premium in day-ahead LMPs compared to real-time LMPs ($60.58/MWh vs. $60.28/MWh). Participants also cleared lower levels of fixed demand (64.2% vs. 64.5%) compared to Fall 2021. However, levels of price-sensitive demand and virtual demand more than offset the decrease in fixed demand. In Fall 2022, price-sensitive demand accounted for 33.6% of real-time demand compared to 32.2% in Fall 2021. Virtual demand's contribution increased from 2.7% to 3.2% year-over-year. 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.

[12] 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.

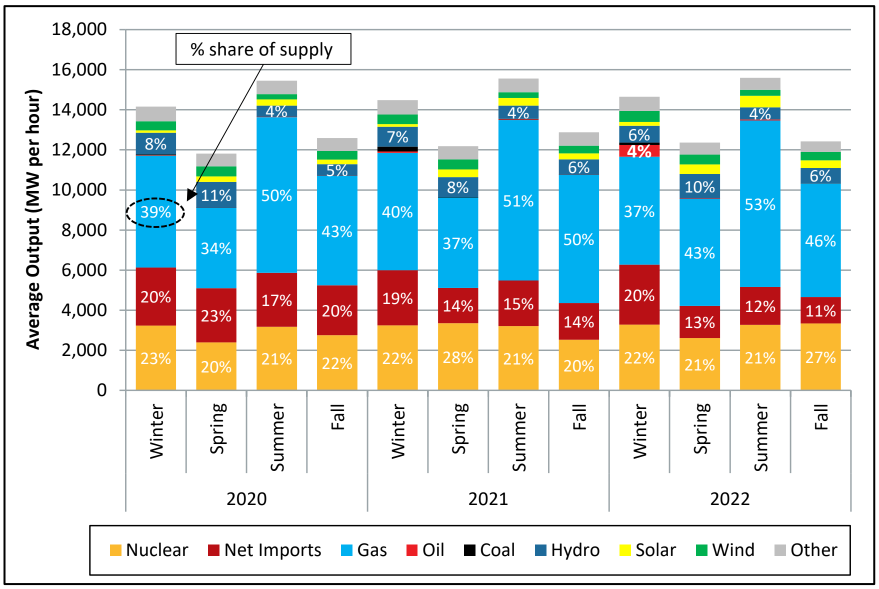
2.3 Supply

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 2020 through Fall 2022 are illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the share of generation from each fuel type.[13]

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



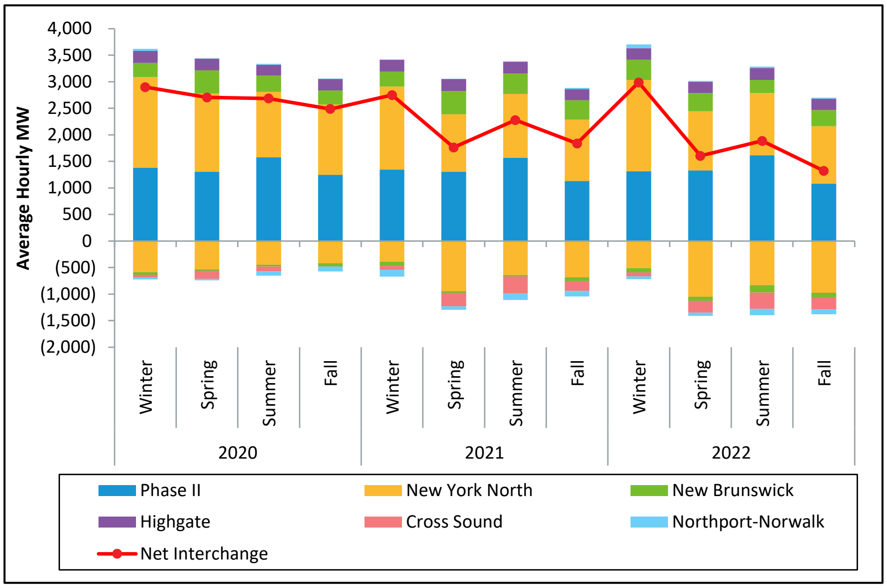
The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (imports netted for exports). Together, these categories accounted for 83% of total energy production in Fall 2022. Average nuclear generation was about 811 MW per hour higher in Fall 2022 (3,338 MW) than in Fall 2021 (2,527 MW), when two nuclear generators went out of service for planned refueling outages. This increase in nuclear power displaced some gas-fired generation, which fell by an average of 720 MW per hour between Fall 2021 (6,389 MW) and Fall 2022 (5,670 MW). Meanwhile, average net imports also decreased between Fall 2021 (1,837 MW) and Fall 2022 (1,323 MW). The majority of this decrease in net imports occurred at the New York North interface, partly as a result of a smaller price premium in New England in Fall 2022 than in Fall 2021.

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

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 Fall 2022.[14] On average, the net flow of energy into New England was 1,323 MW per hour. Total net imports represented 11% of load (NEL), which was lower than the prior 11 seasons. Overall, net imports decreased by 28% (or 515 MW). The reduced net interchange results in more expensive generation being dispatched within New England. Therefore, the reduced net interchange contributed to higher average LMPs. The average hourly import, export, and net interchange power volumes by external interface for the last 12 quarters are shown in Figure 2-8 below.

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



Hourly net interchange averaged 1,323 MW, down 30% (or 564 MW) from Summer 2022 (1,886 MW) and down 28% (or 515 MW) from Fall 2021(1,837 MW). Net interchange typically decreases from summer to fall due lower energy demand and LMPs, and increased planned transmission outages between New England and the other control areas. Compared to Summer 2022, net interchange decreased across New York North, Phase II, and Highgate, but increased at Cross Sound Cable, Northport-Norwalk and New Brunswick. At the New Brunswick interface, net imports increased following the completion of a nuclear power plant outage in New Brunswick at the end of Summer 2022.[15]

Compared to Fall 2021, total net interchange fell due to decreased flows over the New York North Interface. Average net imports decreased by 357 MW over the interface due to increased price spreads between New York and New England. At this interface, flows are scheduled based on the price difference, or spread, between New York and New England. While both New York

[14] 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.

[15] The nuclear power plant accounts for 46% of New Brunswick's native generation. For more information on the outage, see this link.

and New England saw increased prices at this interface, New York prices increased by more than New England. This caused an increased price spread, and participants imported less power from New York into New England.

Below, we provide a more detailed explanation of trends and drivers in flows across the two largest external interfaces – Phase II and New York North – which together accounted for 90% of total net imports.

Phase II Interface

The Phase II interface continues to account for the largest share of net interchange (82%) into New England. Phase II's share of total net interchange has risen, on average, over the last 11 seasons as total net interchange at other interfaces has trended down, especially at the New York interfaces. In Fall 2022, net interchange at Phase II averaged 1,083 MW, the lowest net interchange over the reporting period. Average net interchange at Phase II represented a 50 MW (or 4%) decrease compared to Fall 2021 (1,133 MW), and a 531 MW (or 33%) decrease compared to Summer 2022 (1,614 MW). Compared to Summer 2022, volumes largely decreased due to reduced total transfer capabilities associated with transmission work.

New York North Interface

The reduction in net interchange over New York North (NYN) was the main contributor to the overall decrease in net interchange in Fall 2022 compared to Fall 2021. Indeed, there has been a noticeable decline in flows across NYN since Spring 2021. These declines are related to the retirement of a New York nuclear power generator and increased transmission work in New York.

At the New York North interface, hourly average net interchange decreased by 357 MW (or 77%) compared to Fall 2021 (109 MW vs. 466 MW). The main driver behind this difference was the change in the forecasted price spread at the New York North interface. New England forecasted prices were $5.41/MWh lower than New York forecasted prices in Fall 2022 compared to just $1.26 /MWh in Fall 2021, on average. The increase in forecasted price spreads occurred as congestion costs increased in the New York zones bordering New England, especially in New York's Capital Zone. Between Fall 2021 and Fall 2022, the congestion component of the real-time LBMP increased from $13.65/MWh to $33.60/MWh in New York's Capital Zone.[16]

Despite generally higher prices in New York, participants still import power from New York to New England on a net basis. This behavior is likely due to contracts outside of the ISO New England market. Participants may import power across interfaces to fulfill bilateral contracts, such as power purchase agreements, or to meet clean energy standards by purchasing renewable energy certificates (REC). For example, a participant may be willing to take a loss on an import transaction over the New York North interface, because they would receive a lower priced REC from New York compared to one in New England.

[16] LBMP is the New York ISO's Locational Based Marginal Price.

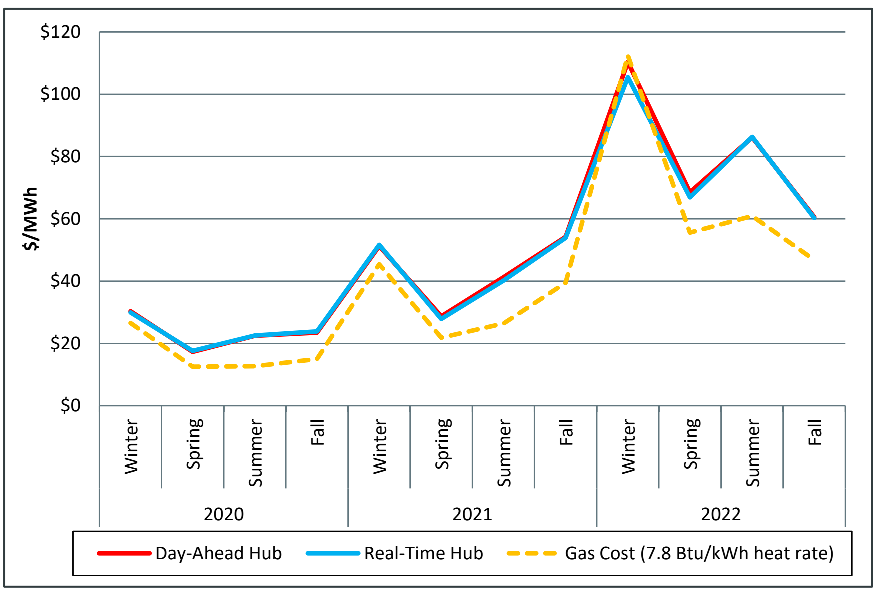
Section 3
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, outcomes in the energy and ancillary services markets. The ancillary services category includes operating reserves and regulation.

3.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. These trends can be seen in Figure 3-1, which shows the average day-ahead and real-time energy prices, along with the estimated cost of generating electricity using natural gas in New England.[17]

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



The average real-time and day-ahead Hub prices for Fall 2022 were $60.28 and $60.58/MWh, respectively. Gas costs averaged $47/MWh in Fall 2022.

The spread between the average day-ahead electricity price and average estimated gas cost was $14/MWh in Fall 2022, similar to the $15/MWh spread in Fall 2021. Spreads were larger during the two most recent fall quarters than in Fall 2020, when the spread was $8/MWh. The increase from Fall 2020 was driven by a substantial rise in natural gas prices (from $1.93/MMBtu in Fall 2020 to $6.00/MMBtu in Fall 2022), which led to an increase in generator

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

costs and LMPs. All else equal, when gas prices and generation costs increase, spark spreads also increase.

Average day-ahead and real-time prices in Fall 2022 were higher than Fall 2021 prices by about $6.40/MWh or 12% in both markets. This increase is consistent with higher natural gas prices in Fall 2022, which rose by 18% compared to Fall 2021. Additional nuclear generation in Fall 2022 muted the impact of higher natural gas prices on LMPs. Two nuclear generators were out of service for refueling during Fall 2021, but there were no notable nuclear generator outages in Fall 2022.

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

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

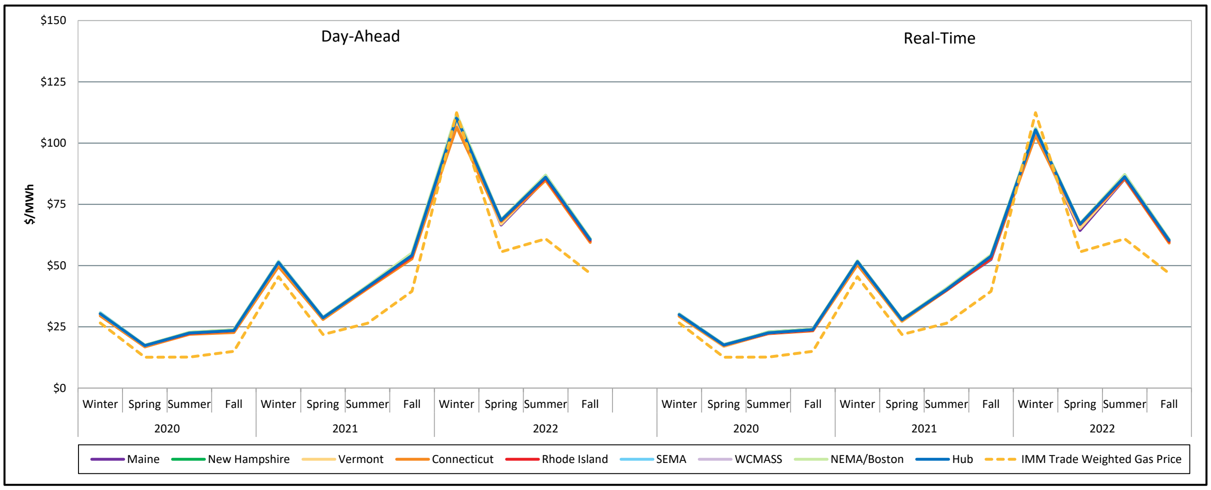


Figure 3-2 illustrates that prices did not differ significantly among the load zones in either market in Fall 2022, indicating that there was relatively little transmission congestion on the system at the zonal level.

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

3.2 Marginal Resources and Transactions

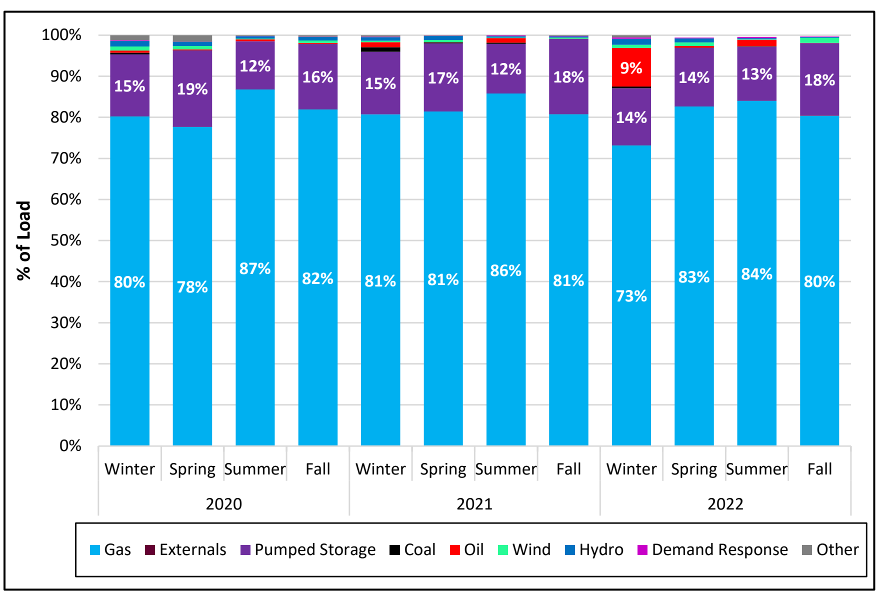
The locational marginal price (LMP) at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is "marginal." Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

This section reports marginal units by transaction and fuel type on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. For example, resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. Consequently, the impact of these resources on the system LMP is muted.

In the day-ahead market, a greater number of transaction types can be marginal; these include virtual bids and offers, fixed and priced-demand, generator supply offers and external transactions. By contrast, only physical supply, pumped-storage demand, and external transactions can set price in the real-time market. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand.

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

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



Despite modest changes in the supply mix that occurred between Fall 2021 and Fall 2022, gas generators continued to set price for a similar percentage of load for the region.[20] Natural gas-

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

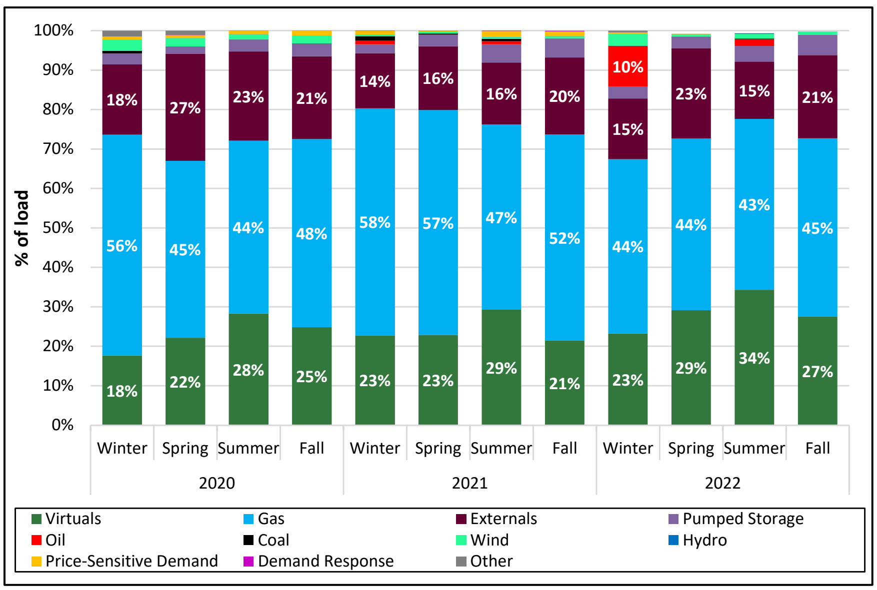
[20] See Section 2.3.1 for more information about changes in generation between Fall 2021 and Fall 2022.

fired generators set price for about 80% of total load in Fall 2022 compared to 81% in Fall 2021. Gas-fired generators are often the most expensive generators operating, and therefore set price frequently. More expensive coal- and oil-fired generators are not typically required to operate to meet system demand during shoulder seasons like the fall, and therefore set price infrequently during these periods.

Pumped-storage units (generators and demand) set price for about 18% of total load in Fall 2022, identical to the percentage in Fall 2021. Pumped-storage units generally offer energy at a price that is close to the margin. Pumped-storage generation is often called upon when conditions are tight due to their ability to start up quickly and their relatively low commitment costs when compared with fossil fuel-fired generators. Pumped-storage demand frequently sets price when energy prices are lower in off-peak hours and they need to replenish their ponds to generate in future hours. Because they are online relatively often and priced close to the margin, they can set price frequently.

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2020 is illustrated in Figure 3-4 below.

Figure 3-4: Day-Ahead Marginal Units by Transaction and Fuel Type

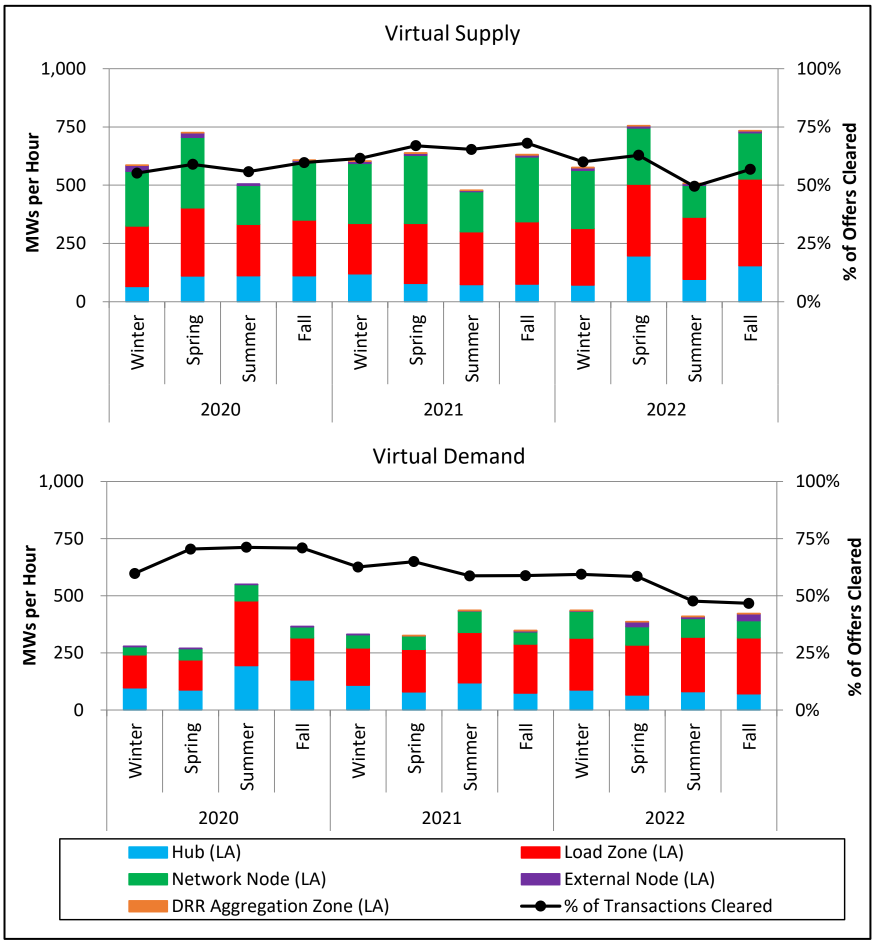


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 45% of total day-ahead load in Fall 2022. This represents a slight reduction from their Fall 2021 value (52%). However, in Fall 2022 gas-fired generators, virtual transactions, and external transactions set price for 94% of load, which is almost identical to their sum in Fall 2021 (93%).

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 3-5 below. Cleared transactions are divided into groups based on the location type where they cleared: Hub (blue), load zone (red), network node (green), external node (purple) and Demand Response Resource (DRR) aggregation zone (orange). The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-5: Cleared Virtual Transactions by Location Type



In Fall 2022, total cleared virtual transactions averaged approximately 1,154 MW per hour, an 18% increase compared to Fall 2021 (979 MW per hour) and a 26% increase compared to Summer 2022 (916 MW per hour).

Total cleared virtual supply averaged 733 MW per hour in Fall 2022, up 45% from Summer 2022 (507 MW per hour) and up 16% from Fall 2021 (631 MW per hour). Virtual supply often 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

Fall 2022, solar SOGs reached an installed capacity of over 1,900 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. 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.[21] In Fall 2022, participants cleared 51% (or 373 MW) of cleared virtual supply offers at load zones, 27% (or 196 MW) at network nodes, 21% (or 154 MW) at the Hub and 1% (or 8 MW) at external nodes.[22]

Cleared virtual demand averaged 421 MW per hour in Fall 2022, up 21% from Fall 2021 (347 MW per hour) and up 3% from Summer 2022 (409 MW per hour). In Fall 2022, participants cleared 58% (or 245 MW) of virtual demand bids at load zones, 18% (or 76 MW) at network nodes, 17% (or 71 MW) at the Hub, and 7% (or 30 MW) at external nodes. DRR aggregation zones accounted for less than 0.1% of cleared virtual demand. For most location types, percentages of cleared virtual demand by location type aligned with the prior season. However, cleared virtual demand at external nodes increased by 24 MW (30 MW vs. 6 MW) compared to Fall 2021, on average. This was due to increased clearing at the Phase II external interface. Participants importing power over the Phase II interface often face the risk of their imports being curtailed in the real-time market. Virtual demand provides these participants with a financial hedge against any curtailments.

3.4 Net Commitment Period Compensation

This section covers quarterly uplift payments and the overall trend in uplift payments over the last three years.

Net Commitment Period Compensation (NCPC), commonly known as uplift, are make-whole payments provided to resources in two circumstances: (1) when energy prices are insufficient to cover production costs; or (2) to account for any foregone profits the resource may have lost by following ISO dispatch instructions. Uplift is paid to resources that provide a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[23]

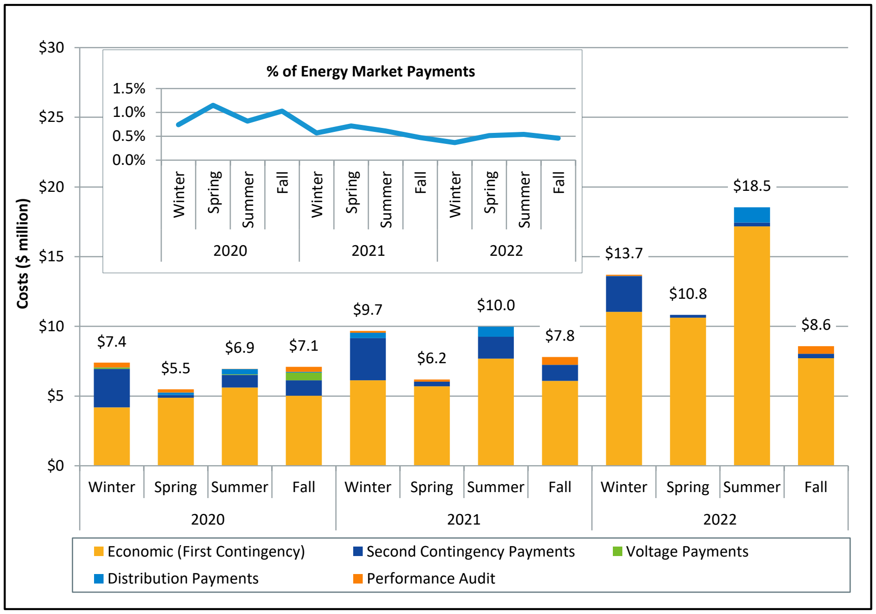
Payments by season and by uplift category are illustrated below in Figure 3-6. The inset graph shows uplift payments as a percentage of total energy payments.

[21] In Fall 2022, real-time wind generation averaged 416 MW.

[22] DRR Aggregation Zones accounted for 0.002% of all cleared virtual supply.

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

Figure 3-6: NCPC Payments by Category



Uplift payments totaled $8.6 million in Fall 2022, an increase of $0.8 million from Fall 2021. This increase was driven by higher first contingency payments due to higher energy prices, and partially offset by low second contingency payments. Uplift represented 0.5% of total energy payments in Fall 2022, slighlty less than the historical average over the reporting horizon of 0.7%.

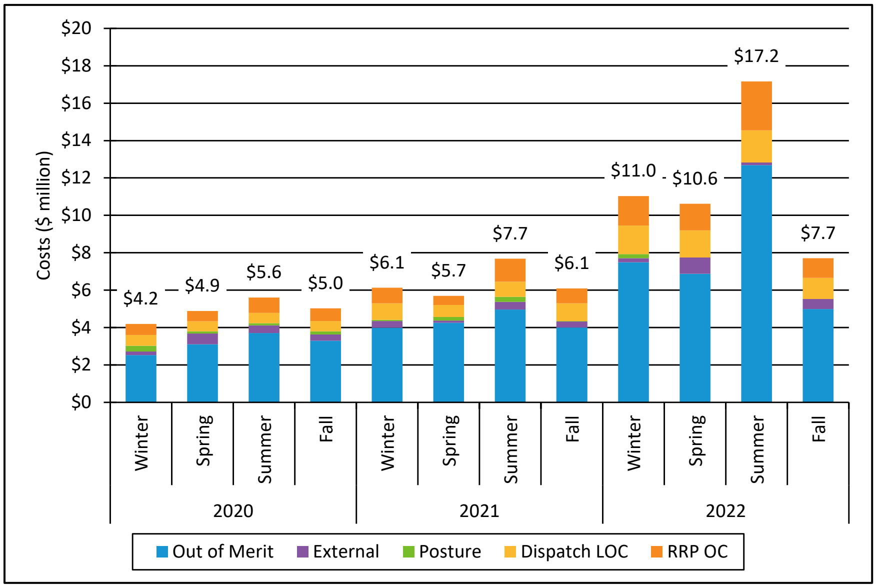
Second contingency payments accounted for 4% ($0.3 million) of uplift payments in Fall 2022, with 98% of payments made in the day-ahead market. Second contingency payments decreased by $0.8 million (72%) compared to Fall 2021. In Fall 2021, planned transmission upgrades in the Boston area and northern New England necessitated day-ahead reliability commitments. The majority (72%) of second contingency payments were paid out in October. Of the October payments, three natural gas-fired generators received a total of 65% or $0.6 million. The Boston import interface was constrained by a high voltage tranmission outage that was in effect the entire month of October and completed in November 2021. Similarly, the Maine – New Hampshire interface was constrained by a high voltage tranmission outage that was in effect for the first half of October.

Economic Uplift

Economic uplift payments comprised the majority of total uplift (90% or $7.7 million) paid in Fall 2022, with 71% of total economic payments made in the real-time market. Economic payments increased by $1.6 million (27%) from Fall 2021 payments.

Economic uplift includes payments made to resources that provide first-contingency protection, external transactions, and resources that operate at an ISO-instructed dispatch point below their economic dispatch point (EDP). This deviation from their EDP creates an opportunity cost for which that resource must be "made-whole" to their forgone profit. First-contingency protection resources receive out-of-merit payments, which ensure recovery of as-offered commitment and dispatch production costs that are not recovered through the LMP. Economic payments by subcategory are shown in Figure 3-7 below.

Figure 3-7: Economic Uplift by Season by Subcategory[24]



Out-of-merit payments, make up the majority of economic uplift (65%). These payments, which mostly cover the commitment costs of in-merit generation, rose by $1.0 million (25%) in Fall 2022 compared to Fall 2021.

3.5 Real-Time Operating Reserves

Bulk power systems must be able to respond quickly to system contingencies, such as the unexpected loss of a large generator. To ensure that additional energy is available in real time to recover from a contingency, the real-time energy market is co-optimized to serve load *and* to maintain sufficient levels of capacity in reserve. This way, if a contingency were to occur, the capacity held in reserve could be activated to provide energy, replacing the energy that was lost as a result of the contingency.

ISO-NE procures three types of real-time operating reserve products:

- **Ten-minute spinning reserve (TMSR)**: This type of reserve is provided by online resources that can increase output within 10 minutes.
- **Ten-minute non-spinning reserve (TMNSR)**: This type of reserve is provided by offline resources that can electrically synchronize to the grid and increase output within 10 minutes.

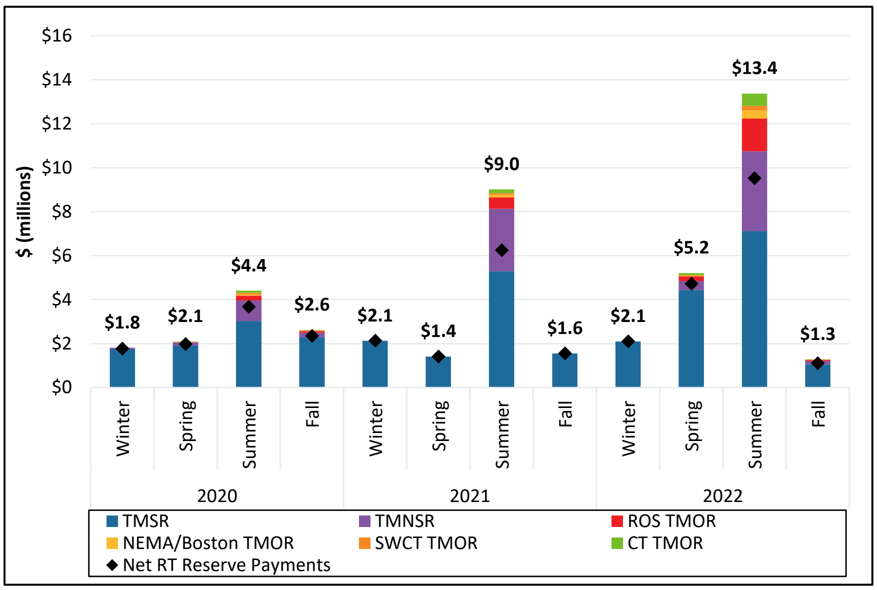
[24] **Out-of-merit NCPC:** Generation is committed in economic merit order to satisfy system-wide load and reserves but fails to recover costs. **External NCPC:** Payments made to external and virtual transactions for relieving congestion at the external interfaces, or to external transactions scheduled out of merit based on actual price. **Dispatch lost opportunity cost NCPC (DLOC):** Payments provided to a resource that is instructed by the ISO to run at levels below its economic dispatch point. **Posturing NCPC:** Payments provided to a resource that follows an ISO manual action that alters the resource's output from its economically-optimal dispatch level in order to create additional reserves. **Rapid-response pricing opportunity costs (RRP OC):** Payments provided to a resource that is instructed by the ISO not to operate at its economic dispatch point when fast-start generators are setting the LMP.

- **Thirty-minute operating reserve (TMOR)**: This type of reserve is provided by online resources that can increase output within 30 minutes or by offline resources that can electrically synchronize to the grid and increase output within 30 minutes.

The ISO's market software determines real-time prices for each reserve product. Non-zero real-time reserve pricing occurs when the software must re-dispatch resources to satisfy a reserve requirement.[25] This happens because resources held in reserve to meet a reserve requirement forgo profit by not producing energy and must be compensated for this lost opportunity so that they are not incented to deviate from ISO dispatch.

Real-time reserve payments by product and by zone are illustrated in Figure 3-8 below.[26] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Market (FRM) units providing real-time reserves).[27]

Figure 3-8: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Fall 2022 ($1.3 million) were down modestly from Fall 2021 ($1.6 million). However, Fall 2022 payments were down significantly from Summer 2022 ($13.4 million), when several periods of extended high temperatures led to tight system conditions with elevated real-time reserve prices. Net real-time reserve payments in Fall 2022 ($1.1 million) were only slightly reduced from their gross levels. The vast majority of reserve

[25] 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.

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

[27] The FRM is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. For more information about the FRM, see Section III.9 of Market Rule 1.

payments in Fall 2022 went to resources providing TMSR ($1.1 million), while relatively small amounts went to resources providing TMNSR ($0.1 million) or TMOR ($0.1 million).

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.

Table 3-1: Hours and Level of Non-Zero Reserve Pricing[28]

Product	Zone	Fall 2022		Fall 2021		Fall 2020	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$9.58	205.7	$7.35	350.5	$7.84	467.2
TMNSR	**System**	$158.74	0.9	$0.00	0.0	$94.68	2.1
TMOR	**System**	$239.63	0.4	$0.00	0.0	$93.19	1.5
	NEMA/Boston	$239.63	0.4	$0.00	0.0	$93.19	1.5
	CT	$239.63	0.4	$0.00	0.0	$93.19	1.5
	SWCT	$239.63	0.4	$0.00	0.0	$93.19	1.5

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 206 hours (9% of total hours) during Fall 2022, which was 145 hours (41%) less than in Fall 2021 and 262 hours (56%) less than in Fall 2020. 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.[29] This operational change contributed to reducing the average ten-minute spinning reserve requirement from 510 MW in Fall 2021 to 393 MW in Fall 2022. However, the average price during the intervals with non-zero pricing in Fall 2022 ($9.58/MWh) was slightly higher than the average prices observed in Fall 2021 ($7.35/MWh) and Fall 2020 ($7.84/MWh). While the average TMNSR and TMOR prices in Fall 2022 were high ($158.74/MWh and $239.63/MWh, respectively), the occurrence of non-zero pricing for both products was less than one hour.

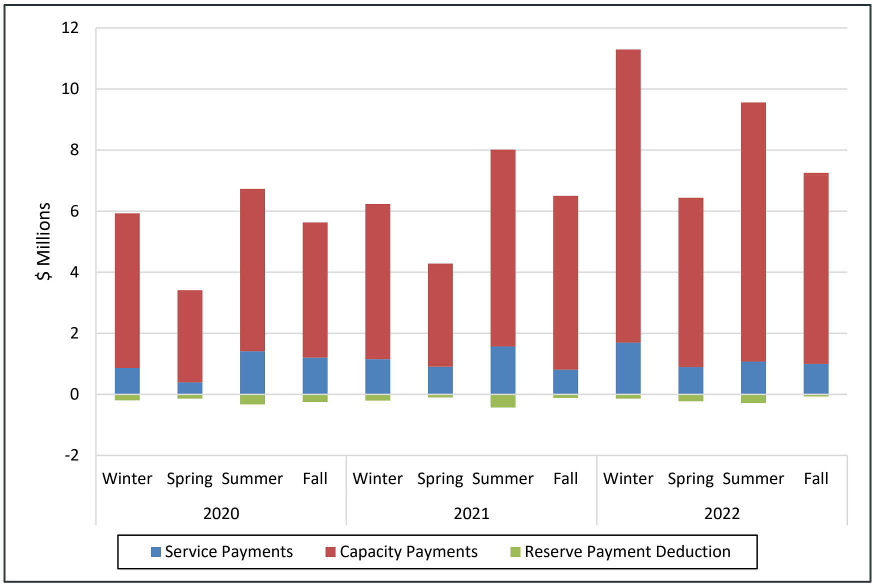
[28] The methodology for this metric has changed. In reports prior to Summer 2019, the sum of payments for each reserve product was averaged over the number of intervals for which *any* reserve price was non-zero, which resulted in low calculations for average non-spinning reserve prices. Now, the table shows the average non-zero price for each respective product and zone. For example, the system TMNSR price was non-zero for 2.1 hours in Fall 2020. Therefore, the table shows the average system TMNSR price ($94.68) during these 2.1 hours.

[29] 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.

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.[30] Quarterly regulation payments are shown in Figure 3-9 below.

Figure 3-9: Regulation Payments



Total regulation market payments were $7.2 million during the reporting period, up approximately 13% from $6.4 million in Fall 2021, and down by 23% from $9.3 million in Summer 2022. The increase in payments compared to the prior fall period primarily reflects an increase in capacity prices and associated payments for regulation resources (up $0.6 million). The increase in capacity prices resulted from an increase in energy market opportunity costs (reflecting increased LMPs in Fall 2022) and incremental cost savings.[31] An increase in service prices and payments for Fall 2022 (up $0.2 million) also contributed to the increase in regulation payments.

Comparing Summer 2022 to Fall 2022, the reduction in total payments resulted from a decline in capacity payments (down $2.2 million). The decline in capacity payments reflects a significant reduction in energy market LMPs and energy market opportunity costs for regulation resources. Energy market LMPs declined by 30%, while regulation capacity costs declined by 26%.

30 Non-generator resources providing regulation service in New England are predominantly energy storage devices.

31 Incremental cost saving represents the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer. This compensation (included in regulation prices) replicates a "Vickery" approach to compensating lumpy "supply," and is intended to provide regulation resources with payments approximating the system opportunity cost of obtaining regulation.

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 by quarter using two structural market power metrics at the system level. Section 4.2 provides statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM's reference level.

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 widely-used metrics identify instances when the largest supplier has market power.[32] 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. This analysis presents the average RSI for all five-minute real-time pricing intervals by quarter.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[33] to the sum of each participant's total supply that is available within 30 minutes.[34] When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each quarter to obtain the percentage of intervals with pivotal suppliers.

[32] 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.

[33] 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*]

[34] 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.

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

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

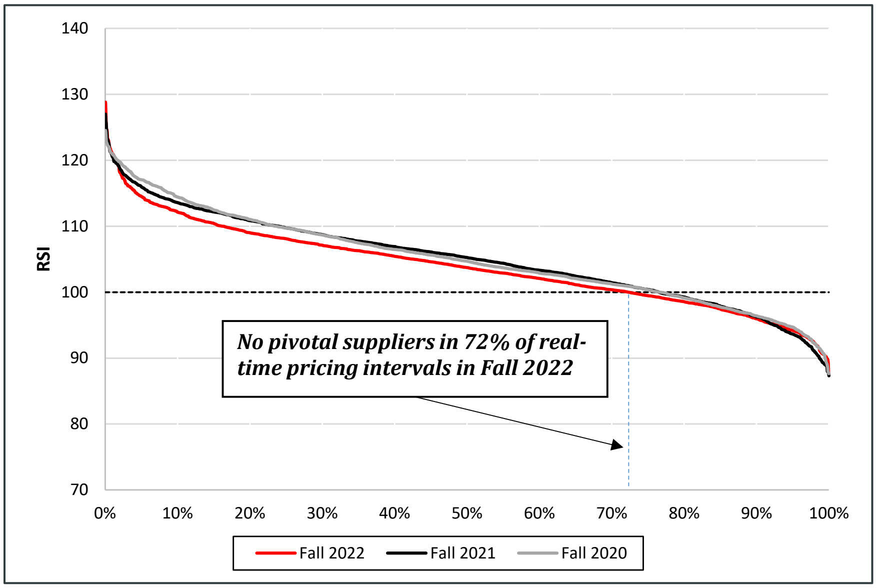
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%

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 Fall 2022 was 28%, which was slightly higher than that of the previous two falls (both 24%), and lower than that of Summer 2022 (34%). The increase was due to lower total 30-minute reserve margins, which decreased by an average of 163 MW compared to Fall 2021. The lower margins were primarily due to a decrease in pumped-storage generator availability. During Fall 2022, pumped-storage generator capacity out-of-service averaged about 390 MW, compared to about 240 MW during Fall 2021. Most of the pumped-storage generator outages for both fall periods were for planned maintenance activities. Pumped-storage generators typically provide a significant portion of non-spinning reserves because they have large capacities and can synchronize to the grid quickly.

Duration curves that rank the average hourly RSI over each fall quarter in descending order are illustrated in Figure 4-1 below. The figure shows the 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 Fall 2022, the RSI was lower than in the previous two falls across most ranked observations due to the lower reserve margins discussed above. The Fall 2021 and 2020 duration curves were similar.

4.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[35] Under certain conditions, the IMM will mitigate generator offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values. The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs.

Appendix A of the ISO's Market Rule 1 outlines the circumstances under which we may mitigate energy market supply offers.[36] These circumstances are summarized in Table 4-2 below.

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

[36] See Market Rule 1, Appendix A, Section III.A.5.

Table 4-2: Energy Market Mitigation Types

Mitigation type	Structure test	Conduct test threshold	Impact test
General Threshold Energy (real-time only)	Pivotal Supplier	Minimum of $100/MWh and 300%	Minimum of $100/MWh and 200%
General Threshold Commitment (real-time only)		200%	n/a
Constrained Area Energy	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only)		25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

We administer seven types of ex-ante supply offer mitigation, and apply up to three criteria when determining whether to mitigate a supply offer.[37] The criteria are:

- *Structural test:* Represents a determination that market circumstances may confer an advantage to suppliers. This may result from (1) a supplier being "pivotal" (i.e., load cannot be satisfied without that supplier) or (2) a supplier operating within an import-constrained area (with reduced competition).
- *Conduct test:* Represents a determination that the financial parameters of a supply offer appear to be excessively high, relative to a benchmark offer value (a "reference" value).[38] The conduct test applies to all mitigation types.
- *Impact test:* Represents a determination that the original supply offer would have a significant impact on energy market prices (LMPs).[39] This test only applies to general threshold energy and constrained area energy mitigation types.

[37] Ex-ante mitigation refers to mitigation applied prior to the finalization of the day-ahead schedules and real-time commitment/dispatch. There is one additional mitigation type specific to dual-fuel generators not listed in the summary Table. Dual-fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (e.g., if offered as using oil, but the generator actually runs using natural gas). This mitigation will affect the amount of NCPC (uplift) payments the generator is eligible to receive in the market settlements.

[38] See Market Rule 1, Appendix A, Section III.A.7, regarding the determination of reference values.

[39] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

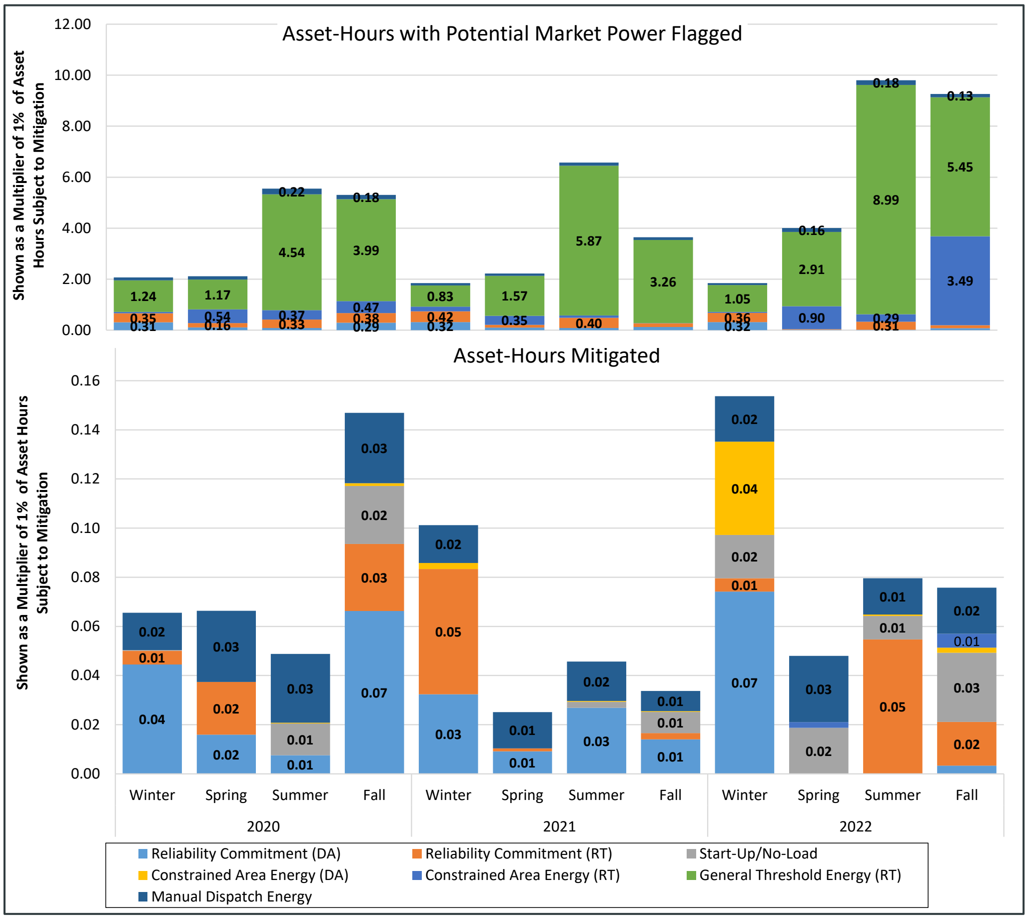
Energy Market Mitigation Frequency

Energy market supply offers are mitigated only when an offer has failed all applicable tests for a particular mitigation type. This section summarizes three types of mitigation data: "structural test" failures, generator commitment or dispatch hours, and mitigation occurrences. The structural test represents an initial condition for applying conduct and market impact mitigation tests for generators in constrained areas or associated with pivotal suppliers (general threshold energy mitigation). For other mitigation types, the commitment or dispatch of a generator triggers the application of the conduct test, when determining whether to mitigate a supply offer.

An indication of mitigation frequency, relative to opportunities to mitigate generators, is illustrated in Figure 4-2 below.[40] 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.

[40] Asset hours refer to the commitment and operation hours of a generator. 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 a 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, commitment hours for Startup and No Load (SUNL) mitigation are not shown because mitigation hours equal commitment hours.

Figure 4-2: Energy Market Mitigation[41]



On average in each quarter, there are approximately 300 thousand asset-hours of ISO-committed generation that are subject to the IMM's mitigation rules; in Fall 2022, 298 thousand asset-hours were subjected to the IMM's mitigation rules, with one percent of those hours equaling 2,980 asset-hours. Structural test failures in the Fall 2022 totaled approximately 28,000 asset-hours, which represents 9% of asset-hours subject to mitigation rules or nine times 1% of total asset hours subject to mitigation. Likewise, mitigation asset-hours represent a very small fraction of potential asset-hours subject to mitigation. For example, in the figure, real-time reliability commitment mitigation totaled just 53 asset-hours for Fall 2022, equaling 0.02 asset-hours scaled to 1% (i.e., 53/2,980).

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 for structural test failures, commitment or dispatch. The highest frequency of mitigation occurred for reliability commitments (light blue and orange shading); this resulted from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM's reference offer value being mitigated. General

[41] 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.

threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue and yellow shading) have had the lowest mitigation frequency at close to 0% over the review period. Both of these mitigation types have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[42] 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, Maine and Southeastern Massachusetts-Rhode Island (SEMA-RI) have had the highest frequency of reliability commitment asset-hours, 47% and 39% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past two years, and with the frequency of localized transmission issues within Maine. Very few reliability commitment mitigations occurred in Fall 2022: just 10 asset-hours in the day-ahead market in SEMA-RI.[43] Overall, reliability mitigations declined significantly between Fall 2021 (44 asset-hours) and Fall 2022 (10 asset-hours). This decrease resulted in part from a decline in reliability commitment asset-hours from 389 to 249. A more significant decline in reliability mitigations occurred between Summer (178 asset hours) and Fall 2022. This decline resulted from no longer needing reliability commitments for local distribution system support on Martha's Vineyard.

Start-up and no-load (SUNL) 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).[44] 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. All generators subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just three participants accounted for 90% of these mitigations. There were just 84 asset-hours of SUNL mitigation in Fall 2022.

Constrained area energy (CAE) mitigation:[45] 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 17 asset-hours of CAE

[42] 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.

[43] 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.

[44] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters.

[45] 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.

mitigation has occurred in the real-time energy market and only 6 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 Fall 2022, a constraint in Connecticut resulted in a large number of structural test failures during the month of November (i.e., 10,000 asset-hours). Both planned and unplanned transmission outages caused this constraint. Although this constraint caused a 10-fold increase in structural test failures (compared to Summer 2022), only a total of 23 asset-hours of mitigation occurred during Fall 2022. Consistent with earlier reporting periods, variation in structural test failures results in very little change in the overall rate of constrained-area energy mitigations, which remains at approximately 0% of structural test failures.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. General Threshold Energy mitigation did not occur over the review period. This happened in spite of 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 67% of the structural test failures and five participants accounted for 84% of structural test failures over the review period. The frequency of pivotal supplier asset-hours increased significantly in Fall 2022 (by 59%), compared to Fall 2021. The increase in Fall 2022 is generally consistent with the IMM's pivotal supplier data included in Figure 4-1.[46]

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 26% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). The dispatch hours for this mitigation type, shown in Figure 4-2, simply refer to asset-hours of manually-dispatched generators in the real-time energy market. As these data indicate, 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 Fall 2022, there were 391 asset-hours of manual dispatch and 56 asset-hours of mitigation. Summer 2022 experienced more asset-hours of manual dispatch (585), but slightly fewer asset-hours of manual dispatch mitigation (48). Compared to Fall 2021, manual dispatch asset-hours increased by 14% in Fall 2022, and mitigation asset-hours increased by 115% (from 26 to 56 asset-hours of mitigation).

[46] As noted in Figure 4-1 (Pivotal Supplier and Residual Supply Indices), the mitigation software's pivotal supplier test is different from pivotal supplier metric presented in Section 4.1. The IMM has 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) and in Financial Transmission Rights (FTRs).

5.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[47] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[48] Between the initial auction and the commitment period, there are three discrete opportunities to adjust annual capacity supply obligations (CSOs) called annual reconfiguration auctions. The three auctions are run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their CSO. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and CSOs traded in each commitment period.

The capacity commitment period (CCP) associated with Fall 2022 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 (~1400 MW total) were retained by the ISO for winter fuel security.[49] 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 an estimated total annual cost of $1.65 billion in capacity payments, $0.47 billion lower than capacity payments incurred in FCA 12.

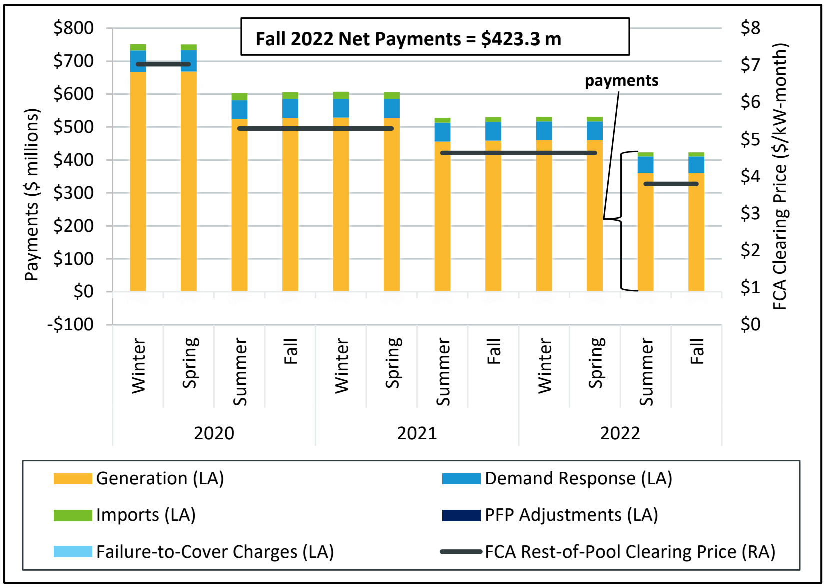
[47] In the capacity market, resource categories include generation, demand response and imports.

[48] Each capacity commitment period is a twelve-month period starting on June 1 of a year and ending on May 31 of the following year

[49] From June 2022 to May 2024, Mystic 8 and 9 will receive supplemental payments per their cost-of-service agreement with the ISO. During Fall 2022, the two Mystic units received a total of $77.6 million in cost-of-service payments.

Total FCM payments, as well as the clearing prices for Winter 2020 through Fall 2022, 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, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The red bar represents reductions in payments due to Peak Energy Rent (PER) adjustment.[50] The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Payments



In Fall 2022, capacity payments totaled over $423 million.[51] Total payments were down 20% from Fall 2021 ($532 million), in line with the 18% decrease in 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 capacity offered at or below the auction clearing price while over 2,100 MW of existing capacity delisted above the clearing price benchmark.

Approximately $20 thousand in Failure-to-Cover (FTC) charges were administered in Fall 2022. 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. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of resources compared to their CSOs. Beginning in Summer 2022, the FTC charge rate calculation changed to better represent the value of undemonstrated capacity. Prior to June 2022, the FTC charge rate was calculated as the maximum clearing price of all primary and reconfiguration auctions associated with a capacity commitment period. As of June 2022, the ISO reruns the third Annual Reconfiguration Auction of each capacity commitment period with all undemonstrated capacity

[50] Peak Energy Rent adjustments were eliminated for Capacity Commitment Periods from June 1, 2019 onward.

[51] Final payments account for adjustments to primary auction CSOs. Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

submitted as mandatory demand bids; the resulting clearing price establishes the FTC charge rate for the capacity commitment period.

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 Fall 2022 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

Table 5-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

					Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	**Auction Type**	**Period**	**Systemwide Price ($/kW-mo)***	**Cleared MW**	**Maine**	**Phase I/II**	**Highgate**	**New Brunswick**
FCA 13 (2022 - 2023)	Primary	12-month	3.80	34,839				
	Monthly Reconfiguration	Nov-22	0.40	920				
	Monthly Bilateral	Nov-22	2.98	7				
	Monthly Reconfiguration	Dec-22	0.55	894				
	Monthly Bilateral	Dec-22	0.77	20				
	Monthly Reconfiguration	Jan-23	3.50	1,089				3.00
	Monthly Bilateral	Jan-23	0.21	132				

**bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions took place in Fall 2022: the November 2022 auction in September, the December 2022 auction in October, and the January 2023 auction in November. Clearing prices trended upwards over the three auctions; beginning at $1.00/kW-month in November and increasing to $0.55/kW-month in December and $3.50/kW-month in January. Despite rising clearing prices, cleared MW volumes remained relatively constant for all three auctions. The January auction cleared the largest volume at 1,089 MW, followed by the November auction at 920 MW, and the December auction at 894 MW.

5.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that settle based on transmission congestion that occurs in the day-ahead energy market. FTRs can be used to manage the risk of transmission congestion for physical supply or demand, or as a completely speculative instrument. FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that helps ensure that the transmission system can support the awarded set of FTRs during the relevant period. FTRs awarded in either of the two annual auctions have a term of one year, while FTRs awarded in a monthly auction have a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[52]

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.

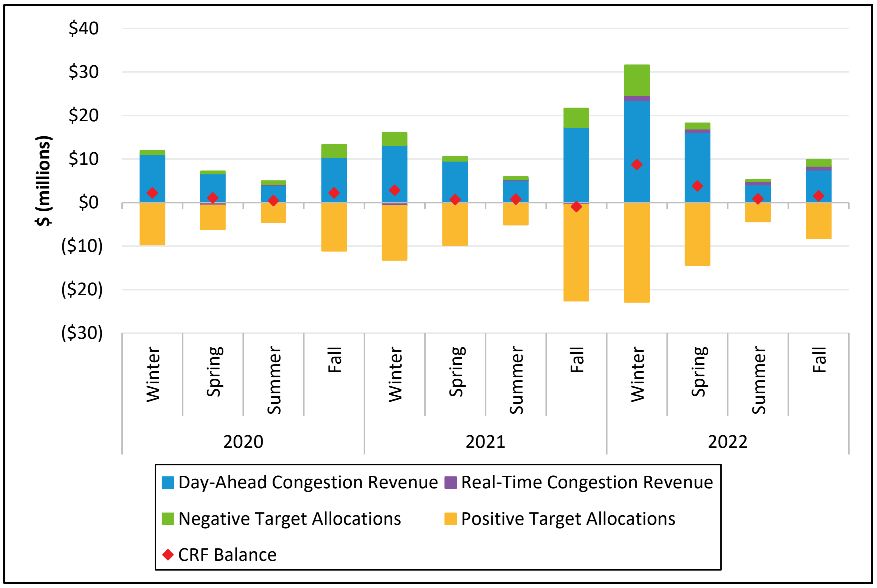
If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected from these three sources to pay the holders of FTRs with positive target allocations in a month. In this case, the payments to holders of FTRs with positive target allocations are prorated. Any excess revenue collected during the year is allocated to these unpaid monthly positive target allocations at the end of the year, to the extent possible.

In general, 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 (i.e., FTRs are usually *fully funded*). This can be seen in Figure 5-2 below, which shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[53] 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.

[52] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location is *greater* than the congestion component of the source location. Negative target allocations (charges) occur when the congestion component of the sink location is *less* than the congestion component of the source location.

[53] The CRF balances depicted in Figure 5-2 are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + |Negative\ Target\ Allocations|) - Positive\ Target\ Allocations$ and do not include any adjustments (e.g., surplus interest, FTR capping). While a positive CRF balance for a quarter indicates that the revenue collected from the three funding sources exceeded the total positive target allocations for the *quarter*, it does not guarantee that this was the case for each *month* within the quarter. As mentioned in the text above, it is important to remember that FTRs settle on a monthly basis.

Figure 5-2: Congestion Revenue and Target Allocations by Quarter



Day-ahead congestion revenue amounted to $7.5 million in Fall 2022. This represents an increase of 82% relative to Summer 2022 ($4.1 million) but a decrease of 56% relative to Fall 2021 ($17.3 million). Positive target allocations in Fall 2022 ($8.2 million) followed a similar pattern, increasing by 90% relative to Summer 2022 ($4.3 million) but decreasing by 63% from Fall 2021 ($22.1 million). Between Fall 2021 and Fall 2022, there were notable decreases in positive target allocations associated with numerous constraints, including the New York - New England interface (NYNE), the Keene Road Export interface (KR-EXP), and the Orrington - South interface (ORR-SO), among others. Similarly, negative target allocations in Fall 2022 (-$1.4 million) rose 296% from their Summer 2022 level (-$0.4 million) but fell 68% from their Fall 2021 (-$4.4 million). Meanwhile, real-time congestion revenue in Fall 2022 ($0.9 million) remained relatively modest and was generally in-line with recent historical levels.

FTRs in September, October, and November 2022 were fully funded, with the CRF balance for the three months (red diamond) totaling $1.6 million. At the end of November 2022, there was a congestion revenue fund surplus of $9.7 million for 2022. As mentioned above, surpluses like this carry over until the end of the year and cover any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid congestion costs.

Transmission work contributed to the congestion that materialized in Fall 2022. Congestion can often result from equipment being taken out of service in order to perform maintenance, repair, or upgrade work. These outages can reduce the transfer capability of the transmission system and alter the flow of power, leading to more congestion. Several of the more impactful transmission constraints in Fall 2022 are listed below. The description attached to each constraint provides some insight into why it experienced congestion in the quarter.

- **South Naugatuck 1580 (S_NAUGTK1580)**: This line is part of the 115kV system in southwestern Connecticut. This constraint bound frequently in both the day-ahead and real-time energy markets during the middle part of November as a result of nearby transmission work and efficient local gas generation behind the constraint.

- **Epping Tap 59BHE-2 (EPPING_T59BHE-2)**: This line is part of the 115 kV system in the eastern part of Maine, a region that has a relatively high concentration of intermittent (predominantly wind) generators. This constraint bound periodically in September, October, and November 2022 in the real-time energy market primarily as the result of wind generation competing to export power over the limited local transmission network. Virtual transactions also led this constraint to bind frequently in the day-ahead energy market as well, as participants actively attempted to profit from the price divergences in this area.