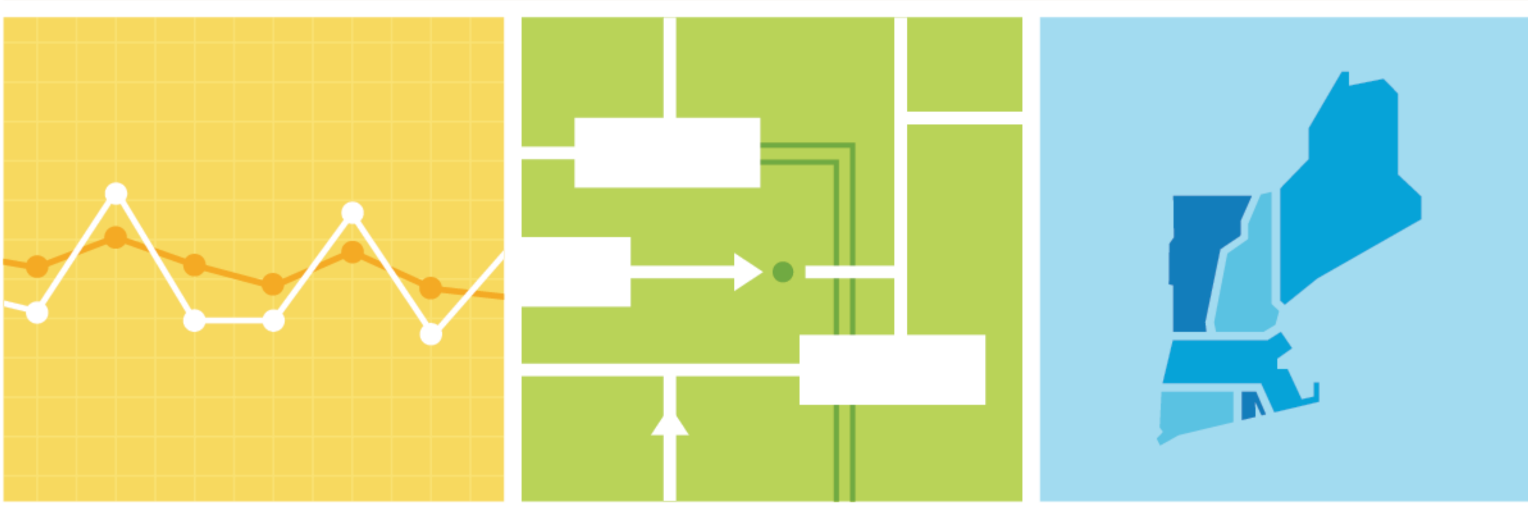
Fall 2021
Quarterly Markets Report

By ISO New England's Internal Market Monitor

JANUARY 25, 2022



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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 2021 (September 1, 2021 through November 30, 2021).

Wholesale Costs: The total estimated wholesale market cost of electricity was $2.20 billion, up 67% from $1.32 billion in Fall 2020. Energy and Net Commitment Period Compensation (NCPC) costs both increased, while capacity market and ancillary services costs decreased.

Energy costs totaled $1.65 billion; a substantial increase of 137% ($952 million) compared to Fall 2020 costs. Higher energy costs were a result of increased natural gas prices (up 163% or $3.14/MMBtu).

Capacity costs totaled $532 million, down 12% ($73 million) from last fall. Beginning in Summer 2021, lower capacity clearing prices from the twelfth Forward Capacity Auction (FCA 12) contributed to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate for all new and existing resources was $5.30/kW-month. This year, the payment rate for new and existing resources was lower, at $4.63/kW-month.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $54.18 and $53.87 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were about 130% higher than Fall 2020 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $5.07/MMBtu in Fall 2021, an increase of 163% compared to $1.93/MMBtu in the prior fall.
- The spread between energy prices and natural gas generation costs was higher compared to the previous fall, which saw historically low natural gas prices. The average implied heat rate for Fall 2021 was within a normal range and similar to that of Fall 2019, but lower than the Fall 2020 average.
- Despite an increase in planned nuclear generator outages and a decrease in net imports, fixed-price supply on the system was about the same during both Fall 2021 and Fall 2020 due to an increase in both self-scheduled generation and output from generators while ramping to their economic minimum level.
- There was limited price separation among the load zones. Day-ahead and real-time average prices in Connecticut, Vermont, and Maine ranged within 3% of the average Hub price due to binding constraints primarily caused by planned transmission outages.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $7.8 million, an increase of 10% ($0.7 million) compared to Fall 2020. NCPC remained relatively low when expressed as a percentage of total energy payments, at 0.5%. The majority of NCPC (78%) was for first contingency protection (also known as “economic” NCPC). At $6.1 million, Fall 2021 economic payments were 21% higher than Fall 2020 payments ($5.0 million). Most of these payments occurred in the real-time market.

At $0.9 million, local second-contingency protection reliability (LSCPR) payments accounted for 12% of total NCPC payments. These payments decreased by $0.2 million relative to Fall 2020 payments. Day-ahead reliability commitments were necessary in Fall 2021 due to planned transmission upgrades in the Boston area and in northern New England.

Real-time Reserves: Real-time reserve payments totaled $1.6 million, a 41% decrease from $2.6 million in Fall 2020. All reserve payments were for ten-minute spinning reserve (TMSR).

The primary drivers of the decrease in reserve payments compared to the previous fall were lower average TMSR prices, fewer instances of very low TMSR margins, and the absence of non-spinning reserve pricing. Though Fall 2021 energy prices were substantially higher than in Fall 2020, the average TMSR price decreased slightly. In Fall 2021, there was an average of 650 MW less supply from net imports and 230 MW less nuclear generation. This reduction in fixed supply was offset by an increase in supply from flexible gas generating resources which, as a consequence of their dispatchability, augmented the available reserves on the system.

Regulation: Total regulation market payments were $6.4 million, up 19% from $5.4 million in Fall 2020. The increase in payments compared to the previous fall primarily reflects an increase in regulation capacity prices and payments for regulation resources. The increase in capacity prices resulted from an increase in both energy market opportunity costs (LMPs increased in Fall 2021) and incremental cost savings. Committed regulation capacity did not change substantially between the two periods. A reduction in service prices and payments for Fall 2021 partially offset the increase in capacity payments.

Financial Transmission Rights: Fall 2021 experienced the most transmission-related congestion of any quarter covered in the reporting period. Increased congestion was driven by planned transmission outages. Day-ahead congestion revenue ($17.3 million), positive target allocations ($22.1 million), and negative target allocations (-$4.4 million) all reached the most extreme values of the last 12 quarters. Meanwhile, real-time congestion revenue in Fall 2021 (-$0.4 million) remained relatively modest and was similar to that of the previous fall.

While FTRs were fully funded in September 2021, they were not fully funded in October or November 2021. In total, there was an underfunding of $0.9 million for the months comprising Fall 2021. One of the major drivers for the underfunding was transmission work that limited the Keene Road Export interface. However, at the end of November 2021, there was a congestion revenue fund surplus of $3.4 million for 2021. Surpluses carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations.

Energy Market Competitiveness: The residual supply index for the real-time market in Fall 2021 was 105, 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 24% of five-minute pricing intervals in Fall 2021. This represents a relatively low frequency, and was similar to the frequency of pivotal suppliers during the previous fall. Fall 2021 saw higher loads and increased baseload outages compared to Fall 2020, but there was more dispatchable generation online in Fall 2021, leading to higher supply margins and fewer instances of tight system conditions. These effects counteracted one another, resulting in similar pivotal supplier frequency values during both Fall periods.

Mitigation continued to occur very infrequently. During Fall 2021, mitigation asset-hours represented a very small fraction of potential asset hours subject to mitigation. Reliability mitigations declined significantly between Fall 2020 (185 asset-hours) and Fall 2021 (44 asset-hours) due to a decline in reliability commitment asset-hours and fewer mitigated offers in Maine and Southeastern Massachusetts Rhode Island (SEMA-RI). Maine and SEMA-RI have had the highest frequency of reliability commitment mitigations throughout the reporting period. This is consistent with transmission upgrades that occurred in SEMA-RI and the frequency of localized transmission issues in Maine over the past two years.

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 2021	Summer 2021	Fall 2021 vs Summer 2021 (% Change)	Fall 2020	Fall 2021 vs Fall 2020 (% Change)
Real-Time Load (GWh)	27,603	33,859	-18%	27,096	2%
Peak Real-Time Load (MW)	20,007	25,807	-22%	19,261	4%
Average Day-Ahead Hub LMP ($/MWh)	$54.18	$41.29	31%	$23.46	131%
Average Real-Time Hub LMP ($/MWh)	$53.87	$40.22	34%	$23.82	126%
Average Natural Gas Price ($/MMBtu)	$5.07	$3.39	50%	$1.93	163%
Average Oil Price ($/MMBtu)	$14.81	$13.03	14%	$8.61	72%

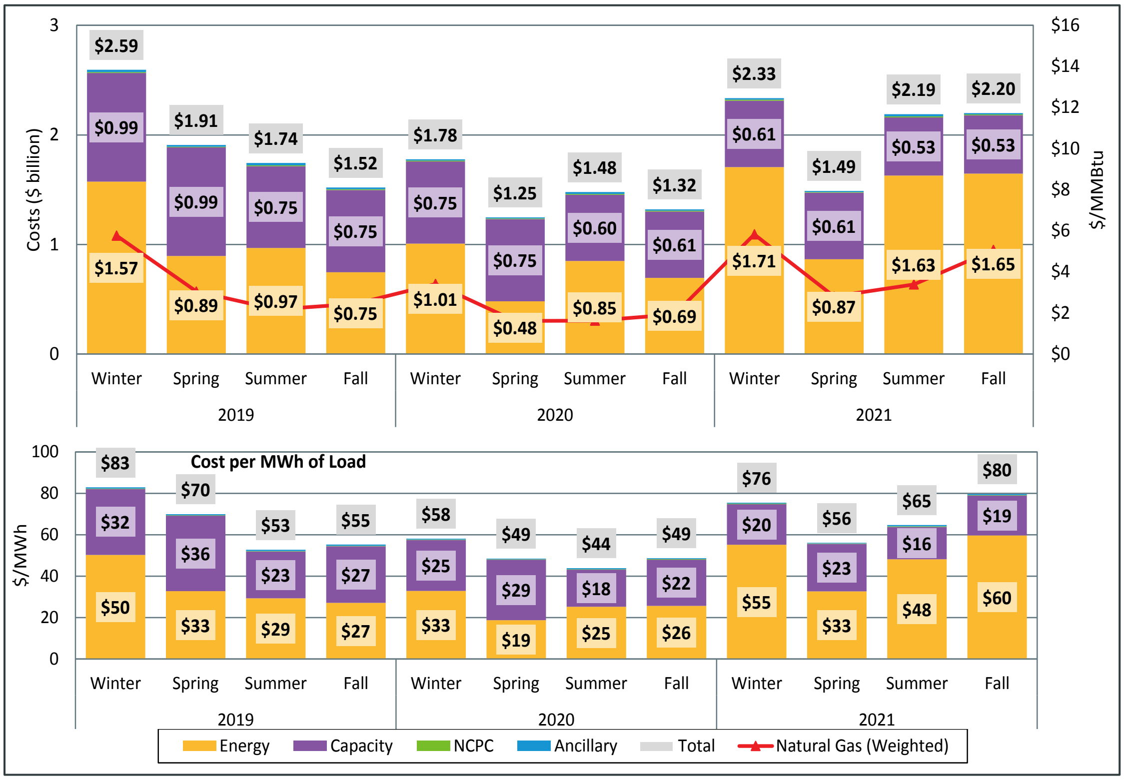
To summarize the table above:

- Day-ahead LMPs averaged $54.18/MWh in Fall 2021, up 131% from Fall 2020 ($23.46/MWh). Higher gas prices in Fall 2021 ($5.07/MMBtu) compared to Fall 2020 ($1.93/MMBtu) put upward pressure on LMPs.
- The increase in gas prices (163%) exceeded the increase in energy prices (126%) because 2020 saw record low gas prices. Fall 2020 gas prices were the lowest since 2000, while Fall 2021 gas prices were the highest since 2008. The high variation in gas prices is not fully reflected in energy prices due to other non-gas price factors such as changes in the supply mix due to planned outages.
- Total load in Fall 2021 (27,603 GWh, or an average of 12,639 MW per hour) was 2% higher than in Fall 2020 (27,096 GWh).

2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [3,4]

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



In Fall 2021, the total estimated wholesale cost of electricity was $2.20 billion (or $80/MWh of load), a 67% increase compared to $1.32 billion in Fall 2020. This increase was driven by an increase in energy costs. Total costs were similar to the previous quarter (Summer 2021), which is notable because shoulder season (Spring and Fall) costs are typically lower than Summer costs. The share of each wholesale cost component is shown in Figure 2-2 below.

Energy costs, which comprised 75% of the total wholesale cost, were $1.65 billion ($60/MWh) in Fall 2021, 137% higher than Fall 2020 costs, driven by a 163% increase in natural gas prices. Natural gas prices, which saw record lows in 2020 and record highs in 2021, continued to be a

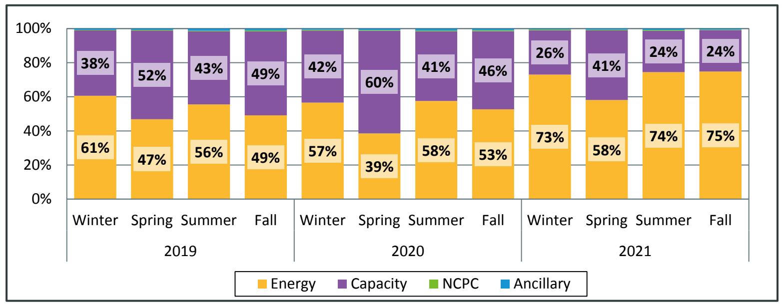
[3] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified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

[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.

key driver of energy prices. The Fall 2020 natural gas price ($1.93/MMBtu) was the lowest Fall price since 2001, while the Fall 2021 natural gas price was the highest since Fall 2008.

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 12), and totaled $532 million ($19/MWh), representing 24% of total wholesale energy costs. Beginning in Summer 2021, capacity market costs decreased relative to previous quarters due to lower forward capacity auction payments. In the prior capacity commitment period (CCP 11, June 2020 – May 2021), the clearing price for all new and existing resources was $5.30/kW-month. In the current capacity commitment period (CCP12, June 2021 – May 2022), the clearing price for all new and existing resources was $4.63/kW-month. The lower clearing prices resulted in decreased capacity costs.

Figure 2-2: Percentage Share of Wholesale Cost



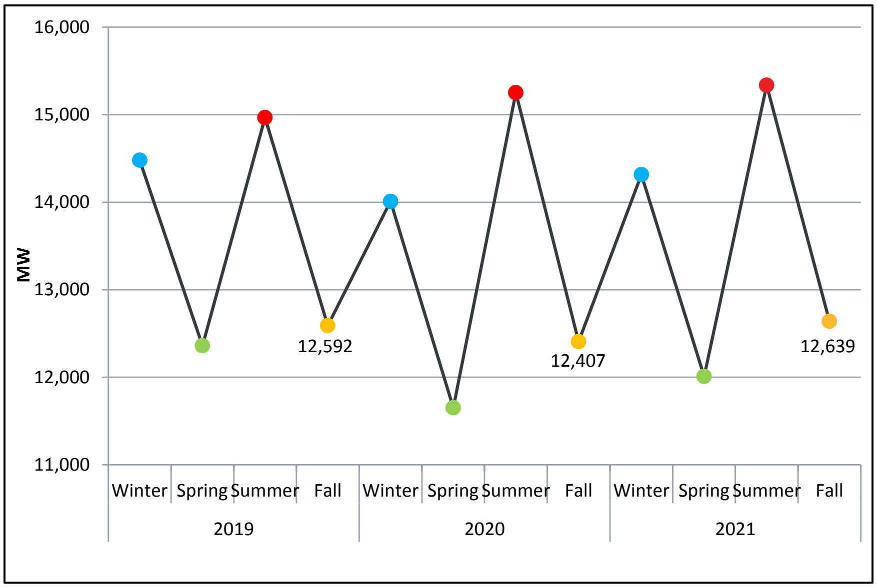
At $7.8 million ($0.28/MWh), Fall 2021 Net Commitment Period Compensation (NCPC) costs represented 0.5% of total energy costs, a slightly lower share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $0.7 million (or 10%) higher than in Fall 2020, driven by an increase in first contingency payments.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $12.5 million ($0.45/MWh) in Fall 2021, representing less than 1% of total wholesale costs. Ancillary service costs decreased by 4% compared to Fall 2020 costs, and decreased by 38% compared to Summer 2021 costs.

2.2 Load

In Fall 2021, average loads increased 1.9% compared to Fall 2020 as more cloud coverage led to less behind-the-meter photovoltaic generation and impacts from the COVID-19 Pandemic continued to push loads higher, particularly during September, which experienced more humid conditions.[5] 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 2021, loads averaged 12,639 MW, a 1.9% (or 232 MW) increase compared to Fall 2020 (12,407 MW) and a 0.4% (or 47 MW) increase compared to Fall 2019 (12,592 MW). Average load increased year over year despite similar levels of Heating Degree Days (HDD) and Cooling Degree Days (CDD).[6] Higher loads occurred due to less cloud cover, which caused an estimated 60 MW decrease (226 MW vs. 285 MW) in behind-the-meter solar generation compared to Fall

[5] 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).

[6] 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. Cooling degree day (HDD) 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.

2020.[7] Also, ISO-NE's backcast model shows that the COVID-19 Pandemic is likely causing higher than expected loads under prior economic conditions.[8]

Load and Temperature

While less behind-the-meter solar generation and the COVID-19 Pandemic led to higher loads, weather still had varying impacts on monthly loads during Fall 2021. 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 to monthly total cooling degree days (CDDs). The bottom panel compares average monthly average load to monthly total heating degree days (HDDs).

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

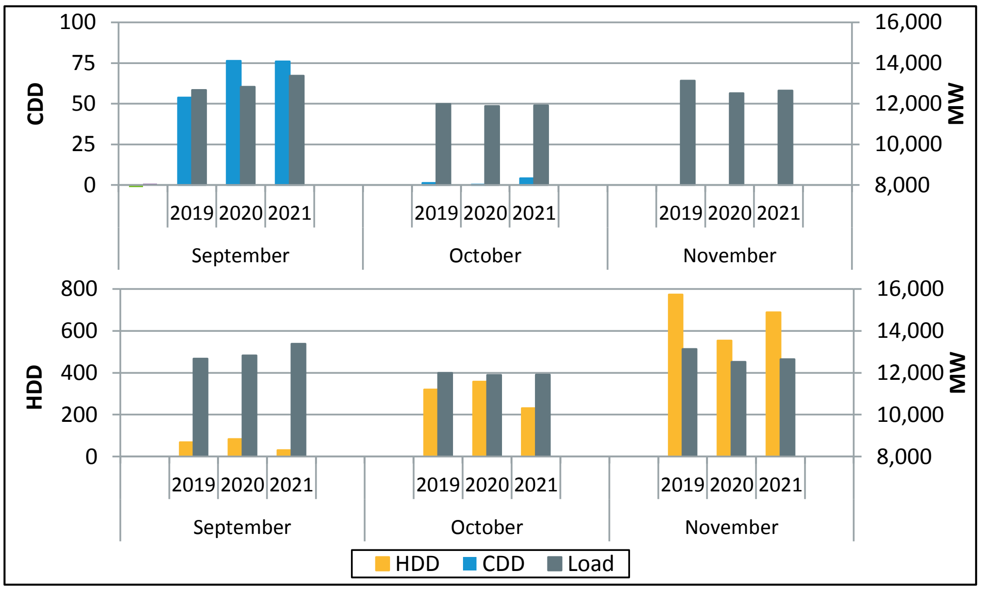


Figure 2-4 shows that loads were higher in every month compared to the prior year. This includes September 2021 and October 2021, which had milder weather and fewer total degree days than September 2020 and October 2020, respectively. While loads still increased year over year, the number of degree days prevented loads from further increasing. In September 2021, loads averaged 13,378 MW, a 551 MW increase compared to September 2020 (12,827 MW) despite the same number of CDDs (76) and a decreased number of HDDs (31 vs. 84). While CDDs did not increase, more humid weather contributed to higher loads in September 2021. In October 2021, loads increased by 21 MW (11,913 MW vs. 11,892 MW) despite warmer average

[7] Typically, behind-the-meter solar installed capacity and generation see significant increases each year. However, estimates show that behind-the-meter solar generation decreased and installed increased by only 2.6% (~2,600 MW vs. ~2,540 MW). In addition to increased cloud cover, another reason for the decrease in behind-the-meter solar generation may have been due to increased registration of these assets with ISO-NE. Previously unregistered solar generation (i.e. behind-the-meter) likely registered as settlement-only generators. These newly registered assets switch from counting towards behind-the-meter solar generation (i.e. reducing load) to counting towards net energy for load. In Fall 2021, the installed capacity of settlement-only solar generation increased by 28%, or 362 MW (1,651 MW vs. 1,289 MW) year over year.

[8] For information on the impact of the COVID-19 Pandemic on demand, see the [Estimated Impact of COVID-19 on ISO New England Demand](https://www.iso-ne.com).

temperature (57°F vs. 53°F). November 2021 also saw higher loads compared to November 2020 (12,650 MW vs. 12,517 MW). Higher loads occurred due to colder temperatures (42°F vs. 46°F), which led to more HDDs (688 vs. 554).

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 2021 is shown in red, while Fall 2020 is shown in black and Fall 2019 is shown in gray.

Figure 2-5: Load Duration Curve

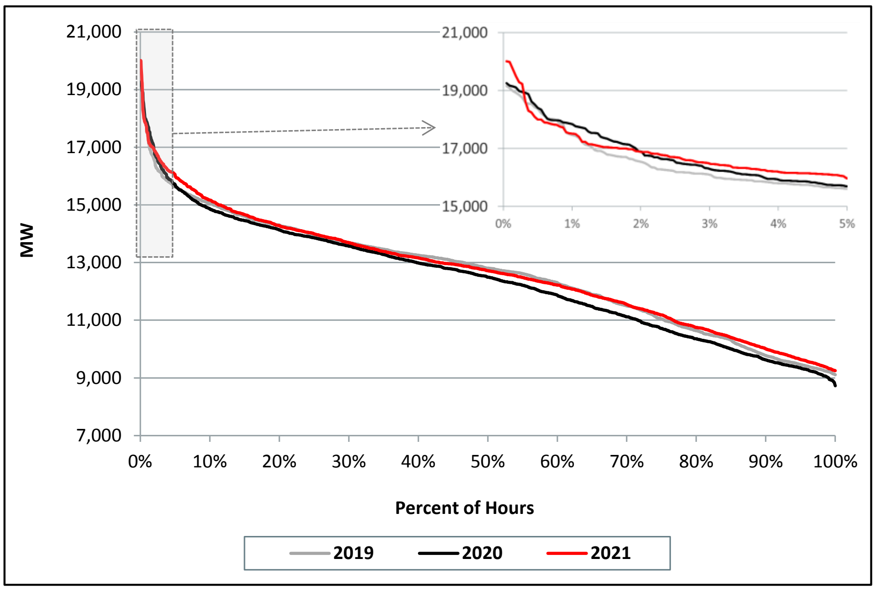
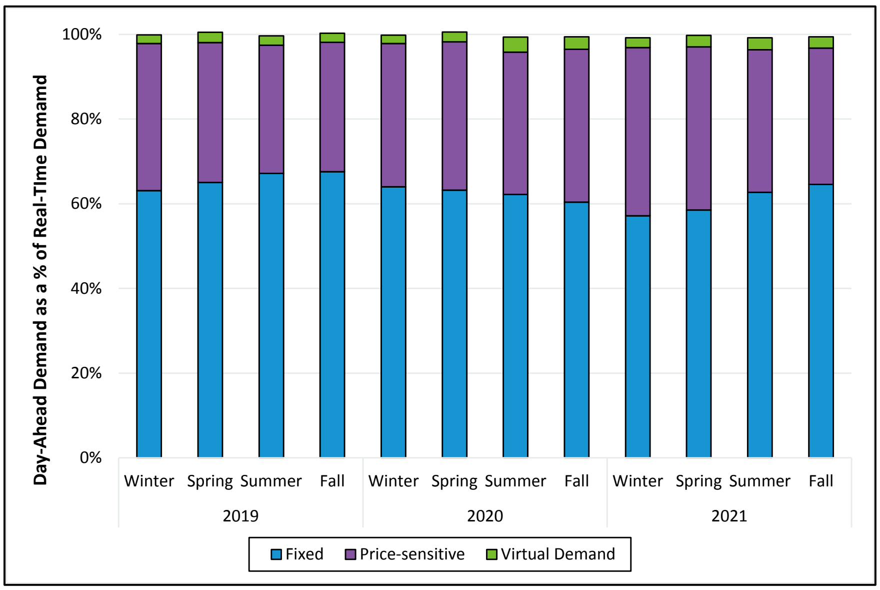


Figure 2-5 highlights that loads in Fall 2021 were higher across more than 98% of observations when compared to Fall 2020 and higher across more than 59% of observations when compared to Fall 2019. In Fall 2021, loads were higher than 14,000 MW in 24.7% of all hours compared to 22.0% and 24.2% in Fall 2020 and 2019, respectively. During the top 5% of hours, Fall 2021 loads increased slightly from Fall 2020 and Fall 2019, respectively. In Fall 2021, the load in the top 5% of all hours averaged 16,922 MW, which was 65 MW higher than the Fall 2020 average (16,857 MW) and 310 MW higher than the Fall 2019 average (16,612MW). The inset graph also shows that loads were higher than prior years during the top 0.3% of all hours. These higher load levels occurred on September 15, 2021 between HE 14 to HE 20. On this day the average New England temperature reached a peak of 83°F, the hottest day of Fall 2021.

Load Clearing in the Day-Ahead Market

For the past several years, day-ahead cleared demand as a percentage of actual real-time demand has increased, on average. The amount of demand that clears in the day-ahead market is important because along with the ISO's Reserve Adequacy Analysis, it influences the generator commitment decision for the operating day.[9] For example, when low levels of demand clear in the day-ahead market, additional generators may be committed to meet real-time demand. This can lead to higher real-time prices. 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.[10]

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



In Fall 2021, participants cleared 99.4% of their real-time demand in the day-ahead market, which was unchanged from Fall 2020 (99.4%) but lower than in Fall 2019 (100.3%). While overall day-ahead cleared demand as a percentage of real-time demand remained unchanged, cleared levels of the individual bid types did fluctuate. Participants cleared more fixed demand in the day-ahead market during Fall 2021 (64.6%) compared to Fall 2020 (60.4%). However, participants cleared lower levels of price-sensitive demand (32.2% vs. 36.1%) and virtual demand (2.7% vs. 2.9%) compared to Fall 2020, offsetting the increase in fixed demand.

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

[10] 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.

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.

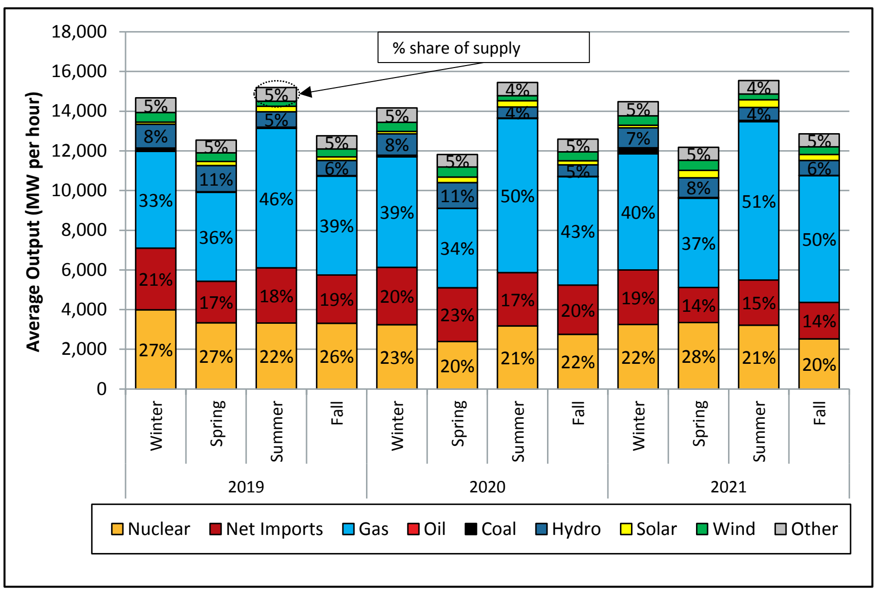
2.3 Supply

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 2019 through Fall 2021 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.[11]

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 84% of total energy production in Fall 2021. Average nuclear generation was about 226 MW lower in Fall 2021 (2,526 MW), compared to Fall 2020 (2,753 MW). The decrease was driven by planned refueling outages of two nuclear generators. Average net imports were 649 MW lower in Fall 2021 (1,837 MW), compared to Fall 2020 (2,487 MW). Transmission work across the New York North and Phase II interfaces led to lower total transfer capability, which reduced the amount of imports that could safely flow into New England. An increase in gas generation (by 927 MW in Fall 2021) offset the decline in imports and nuclear generation. To make up for lost net

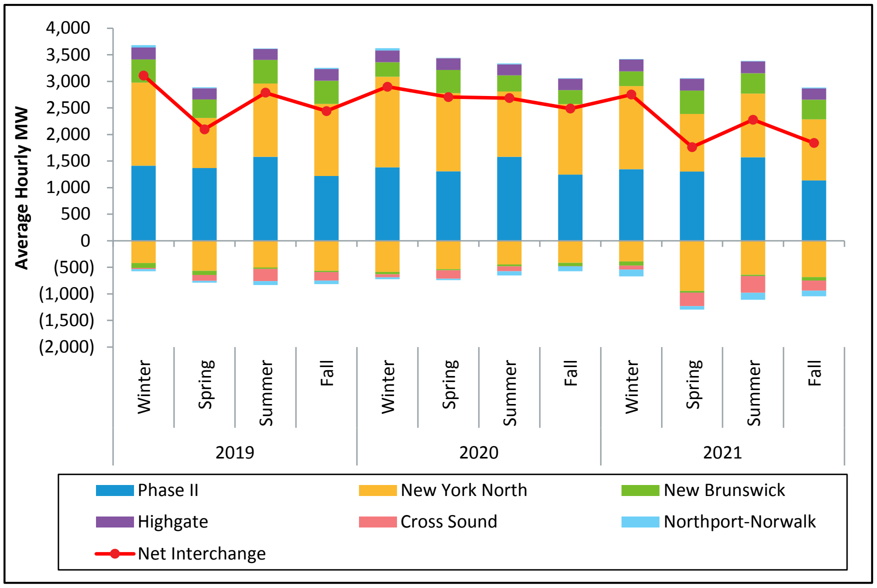
[11] Electricity generation in Section 2.3.1 equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood.

interchange and nuclear generation, natural gas generation increased by 927 MW, on average, in Fall 2021 (6,388 MW) compared to Fall 2020 (5,461 MW).

2.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York in Fall 2021.[12] On average, the net flow of energy into New England was about 1,838 MW per hour, or about 15% of average load. This is slightly lower than the average of the prior 11 seasons (19%). Figure 2-8 shows the average hourly import, export and net interchange power volumes by external interface for the last 12 quarters.

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



The figure shows that average net interchange in Fall 2021 was lower than in both Summer 2021 (decrease of 440 MW an hour) and Fall 2020 (decrease of 650 MW an hour). Compared to Fall 2020, New England's average net interchange decreased from both New York and Canada by 630 MW per hour (77%) and 20 MW per hour (1%) respectively. When compared to Summer 2021, New England's average net interchange increased from New York by 66 MW per hour (53%) and decreased from Canada by 506 MW per hour (24%).

Phase II Interface

The Phase II interface contributed the largest share of net interchange (62%) into New England in Fall 2021. This interface contributed an hourly net interchange average of 1,133 MW in Fall 2021, 9% lower than the hourly average of 1,245 MW in Fall 2020. This fall, the transfer capability over the interface was reduced because of: 1) planned annual maintenance during the second half of September, and 2) transmission outages over the New York North interface that constrained Phase II for reliability. New England generally imports below the 2,000 MW

[12] 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.

maximum transfer capability of the Phase II interface. In Fall 2021, the transfer capability fell below the historic average day-ahead import level of 1,320 MW for 23% of hours. For comparison, the transfer capability fell below this level for only 13% of hours in Fall 2020.

New York North Interface

The New York North interface provided the second largest share of net interchange (25%) into New England in Fall 2021. New England imported an hourly net interchange average of 466 MW over this interface in Fall 2021, 49% lower than the hourly net interchange average of 911 MW in Fall 2020.

The decrease in net interchange over the New York North interface relative to Fall 2020 was primarily the result of: 1) an increase in exports which was driven by a change in planned transmission outages that lowered the total transfer capability of the interface and 2) higher New York energy prices. In the day-ahead market, the average price at the Sandy Pond node was $3.01 higher than the Roseton node and, in the real-time market, the average price at the Sandy Pond node was $1.80 higher than the Roseton node.

Hourly exports over the New York North interface increased by an average of 267 MW (64%) between Fall 2020 and Fall 2021. In addition, fewer cleared imports meant that the net interchange over the New York North interface declined compared to Fall 2020. Hourly imports over the New York North interface decreased by an average of 178 MW (13%) between Fall 2020 and Fall 2021.

This decrease in net interchange was driven by constrained transfer capability. In 2020, the import capability was constrained below the maximum transfer capability of 1,400 MW during 26% of hours. This reduction resulted from an outage that ran from the middle of October through the middle of November 2020 when the interface was reduced to an 800 MW import and 700 MW export capacity. In 2021, the import capability was constrained below 1,400 MW for 56% of hours. These planned outages were spread out across Fall 2021 but each reduction lowered the import capability and constrained imports to 800 MW.

Cross Sound Cable Interface

An increase in exports over the Cross Sound Cable interface also contributed to the average net interchange decrease between New England and New York in Fall 2021. With the exception of 10 days at the end of October to the beginning of November 2020, the Cross Sound Cable was out of service due to maintenance. Average hourly exports over this tie line decreased from 160 MW in Fall 2019 to 7 MW in Fall 2020, on average. In Fall 2021 the average hourly exports increased to 188 MW.

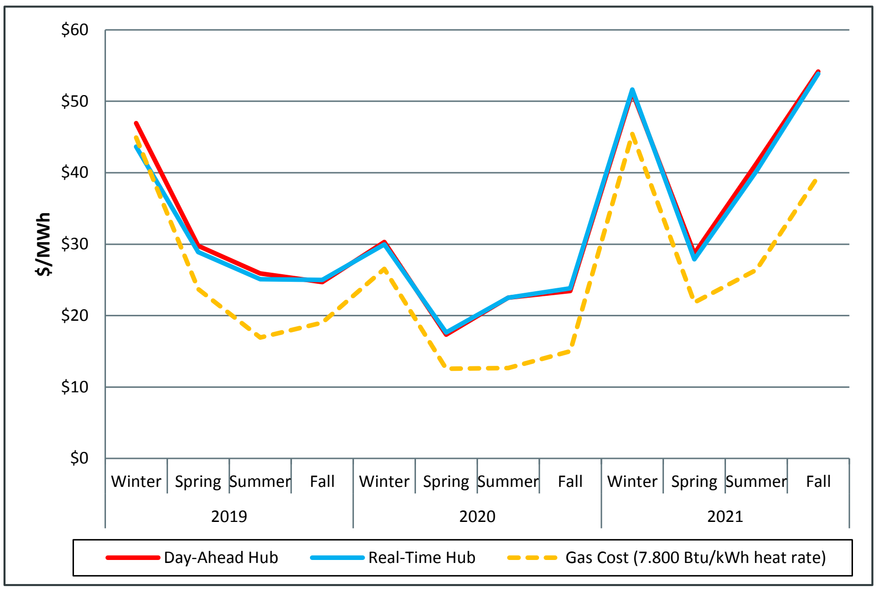
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time and day-ahead Hub prices for Fall 2021 were $53.87 and $54.18/MWh, respectively. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 3-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[13]

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



As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. Gas costs averaged $40/MWh in Fall 2021.

The spread between the average day-ahead electricity price and average estimated gas cost was $15/MWh in Fall 2021. This was significantly higher than the $8/MWh spread in Fall 2020. The larger spread was driven by a substantial rise in natural gas prices, which led to an increase in generator costs and LMPs. All else equal, when gas prices and generation costs increase, spreads also increase. To normalize for fuel prices, we can compare the average implied heat rate for each time period. This rate was 10.7 MMBtu/MWh in Fall 2021, within a typical range

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

and similar to the Fall 2019 value. However, it was slightly lower than the 12.2 MMBtu/MWh rate in Fall 2020, an outlier quarter that saw historically low gas prices. We might expect the Fall 2021 implied heat rate to be higher than the Fall 2020 rate given the higher share of gas generation. However, although there were fewer net imports and additional nuclear generator outages in Fall 2021, the proportion of fixed-price supply on the system was about the same during both periods. Additional self-scheduled generation and up-to-economic minimum supply from dispatchable generators made up for the decrease in fixed supply from imports and nuclear generators.[14]

Average day-ahead and real-time prices in Fall 2021 were higher than Fall 2020 prices by $30.71 and $30.05/MWh, respectively. This is consistent with higher natural gas prices in Fall 2021, which increased by 163% compared to the historically low prices of Fall 2020.

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.

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

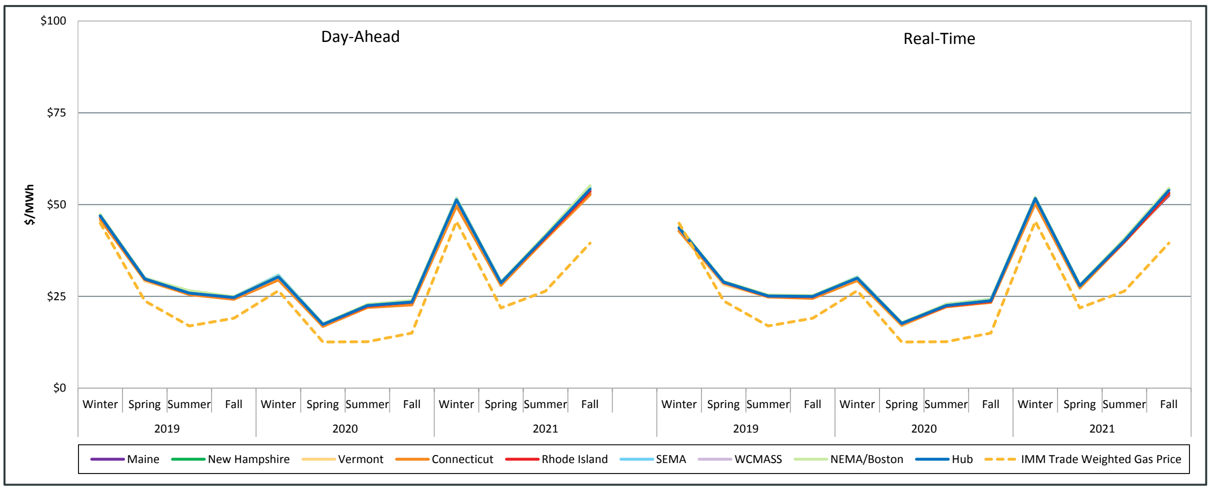


Figure 3-2 illustrates that Fall 2021 prices differed very slightly among the load zones in both markets, indicating that there was a small amount of congestion on the system at the zonal level.[15] In the day-ahead market, average prices in Connecticut, Vermont, and Maine were 2-3% lower than the average Hub price, while average prices in NEMA/Boston were 2% higher. In the real-time market, average Connecticut and Maine prices were 2% lower than the Hub price. These differences were primarily due to binding constraints caused by planned transmission outages.

[14] Generation-up-to economic minimum from economically-committed generators is the portion of output that is equal to or below its economic minimum (EcoMin).

[15] 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

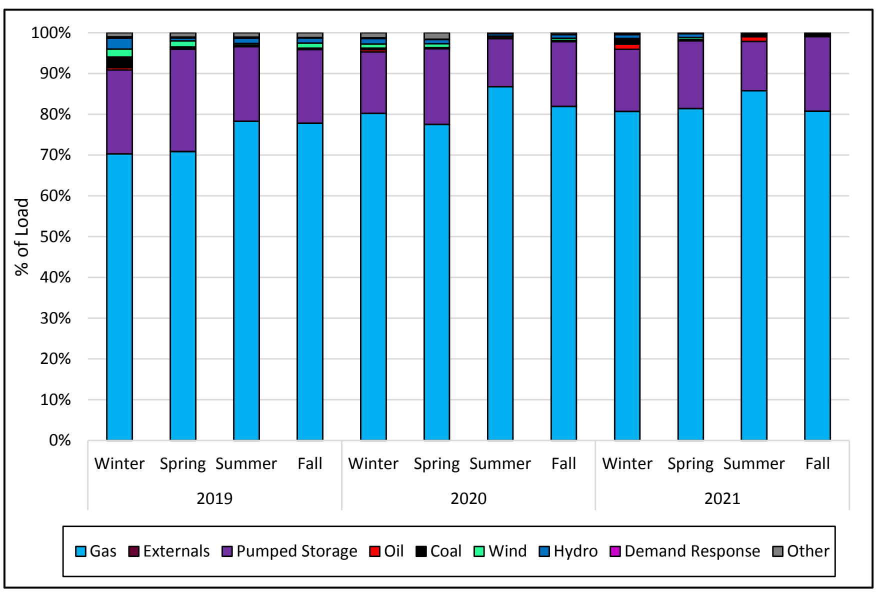
The locational marginal price (LMP) at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is "marginal". Analyzing marginal resources by transaction type can provide additional insight 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.[16]

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



There was little change in price-setting by fuel types between Fall 2020 and Fall 2021. Natural gas-fired generators set price for about 81% of total load in Fall 2021 compared to 82% in Fall 2020. This illustrates that gas generators typically continue to set price for a similar percentage of load for the region despite shifts in the supply curve like we saw between Fall 2021 and Fall

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

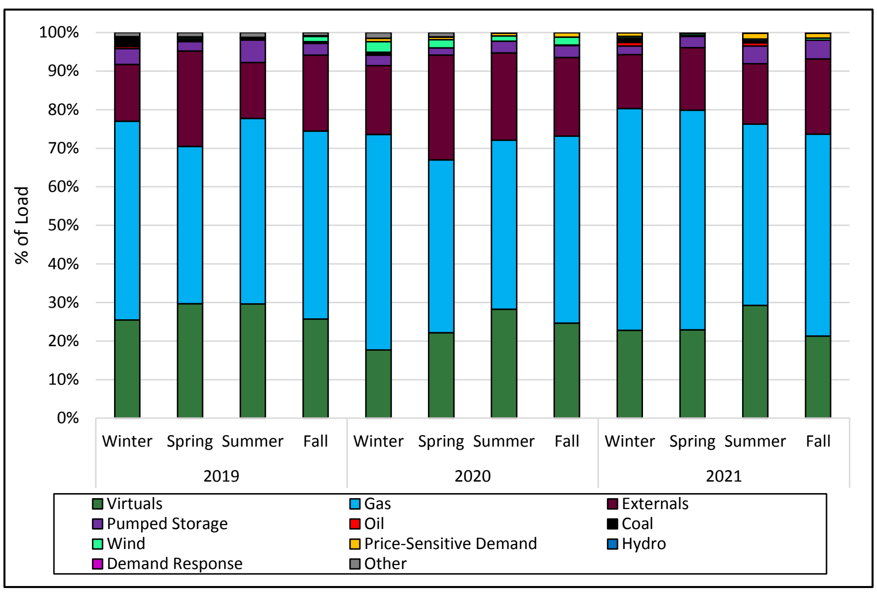
2020 due to reduced import and nuclear generation. Gas-fired generators are often the most expensive generators operating, and therefore set price frequently. More expensive coal- and oil-fired generators are not typically required to operate to meet system demand, and therefore set price less frequently.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchability. By contrast, nuclear generation accounts for one fifth of New England's native generation, but does not set price. Nuclear generators in New England offer at a fixed output, meaning that once they come online they can only produce at one output level. By definition, if load changes by one megawatt they cannot increase or decrease their output to meet the demand, and are therefore ineligible to set price.

Pumped-storage units (generators and demand) set price for about 18% of total load 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 2019 is illustrated in Figure 3-4 below.

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

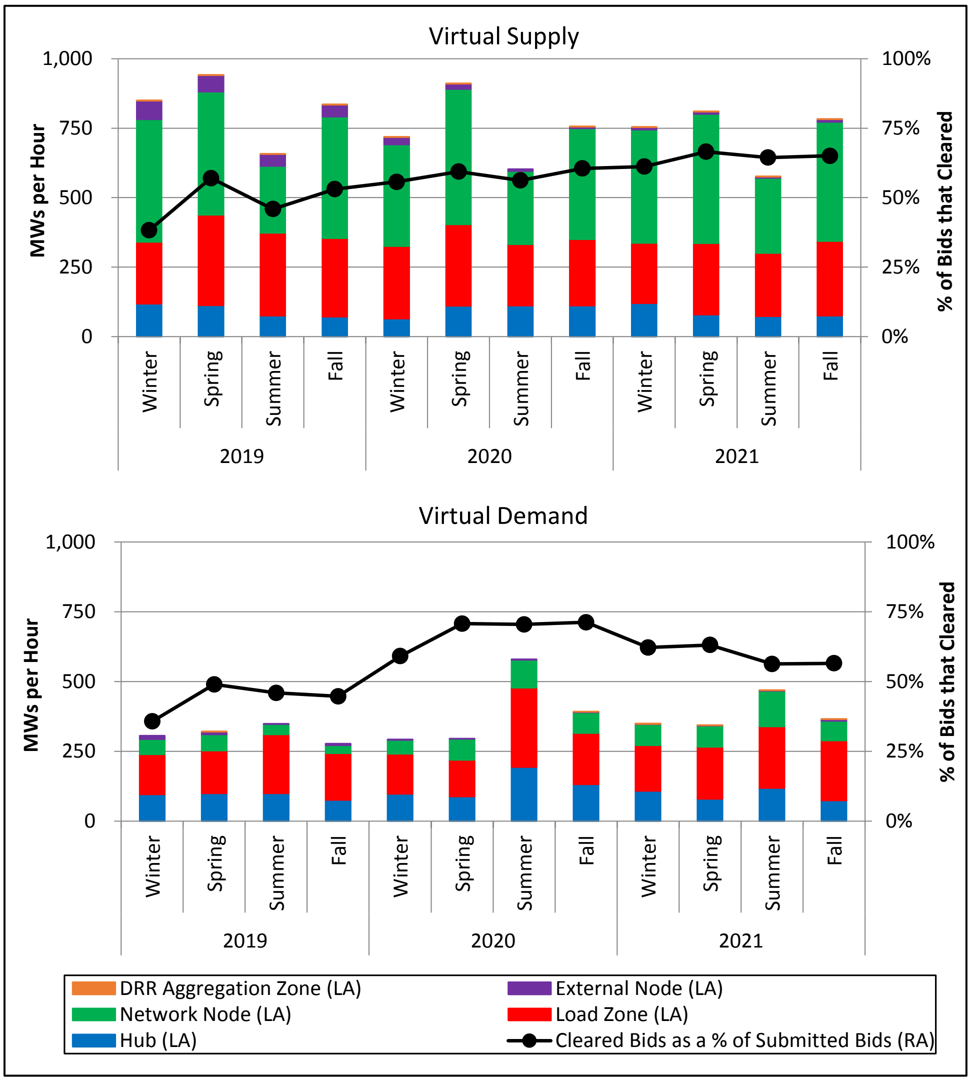


In Fall 2021 gas-fired generators, virtual transactions, and external transactions set price for 93% of load. That is the same amount as Fall 2020. Pumped storage generation set price for more load in Fall 2021 (5%) compared to Fall 2020 (3%), because one of the seven pump storage units returned from a long-term outage. Pumped storage units typically run over the morning and evening peak hours, when their fast-ramping capabilities are most needed.

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. This indicates that the virtual transactions help the day-ahead dispatch model to better reflect real-time conditions. The average volume of cleared virtual supply and virtual demand are shown on the left axis in Figure 3-5 below. Cleared bids are divided into groups, based on the location where they cleared: Hub (blue), load zone (red), network node (green), external node (purple) and DRR aggregation zone. The line graph on the right axis shows cleared bids as a percentage of submitted bids for both virtual supply and virtual demand.

Figure 3-5: Cleared Virtual Transactions by Location Type



In Fall 2021, total *cleared* virtual transactions averaged 1,149 MW per hour, which was 10% higher than the average amount cleared in Summer 2021 (1,046 MW per hour) and just two MW higher than the average amount cleared in Fall 2020 (1,147 MW per hour).

Cleared virtual supply amounted to 783 MW per hour, on average, in Fall 2021, up 36% from Summer 2021 (577 MW per hour) and up 4% from Fall 2020 (756 MW per hour). Typically, participants clear more virtual supply at network nodes than any other location type. Some of this activity is done to capture differences between day-ahead and real-time prices at wind nodes. Wind generators tend to make high-priced energy offers in the day-ahead market, but will produce energy at low, or even negative prices in the real-time market. Cleared virtual supply can help fill the gap and improve price convergence. In Fall 2021, 55% (or 429 MW) of cleared virtual supply occurred at network nodes compared to 34% (or 268 MW) at load zones and 10% (or 75 MW) at the Hub. External nodes cleared 1% of virtual supply and 0.2% cleared at DRR aggregation zones.

Cleared virtual demand amounted to 366 MW per hour, on average, in Fall 2021, down 22% from Summer 2021 (469 MW per hour) and down 7% from Fall 2020 (392 MW per hour). Compared to cleared virtual supply, participants tend to clear a higher percentage of virtual demand bids at load zones and the hub since the same wind-related profit opportunities do not exist for virtual demand. In Fall 2021, participants cleared 59% (or 214 MW) of virtual demand bids at load zones, 20% (or 74 MW) at the Hub, and 19% (or 71 MW) at network nodes. External nodes and DRR aggregation zones cleared 1.5% and 0.1% of cleared virtual demand, respectively.

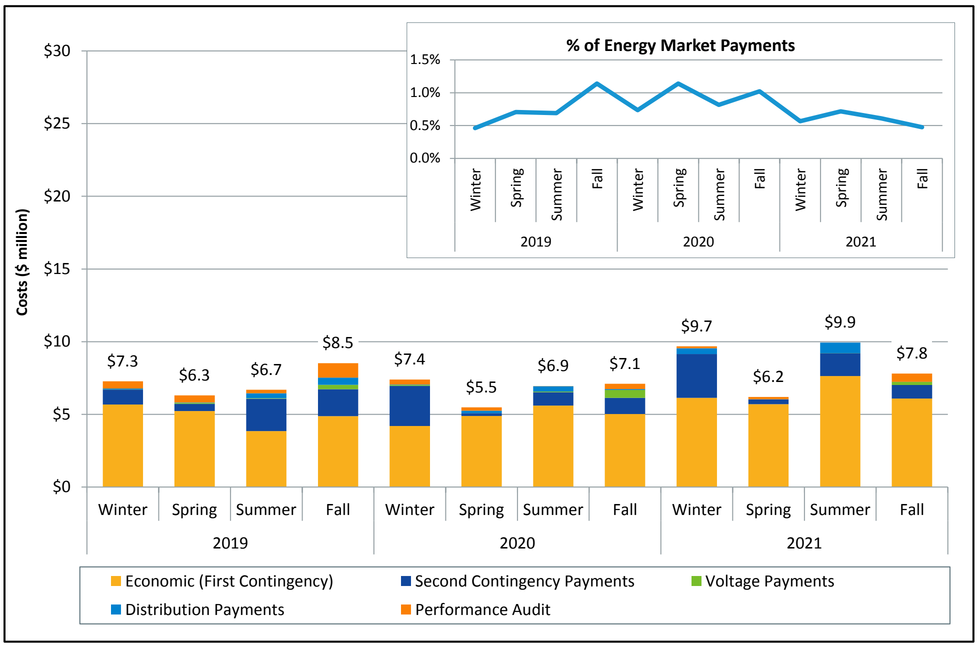
3.4 Net Commitment Period Compensation

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.[17]

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.

Figure 3-6: NCPC Payments by Category



Uplift payments totaled $7.8 million in Fall 2021, a increase of $0.7 million from Fall 2020. This increase was mostly driven by higher first contingency payments due to higher energy prices. Uplift represented 0.5% of total energy payments in Fall 2021, slighlty less than the historical average over the reporting horizon of 0.8%.

Second contingency payments accounted for 12% ($0.9 million) of uplift payments in Fall 2021, with 99% of payments made in the day-ahead market. Second contingency payments decreased by $0.2 million (16%) compared to Fall 2020. In Fall 2021, planned transmission upgrades in

[17] 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).

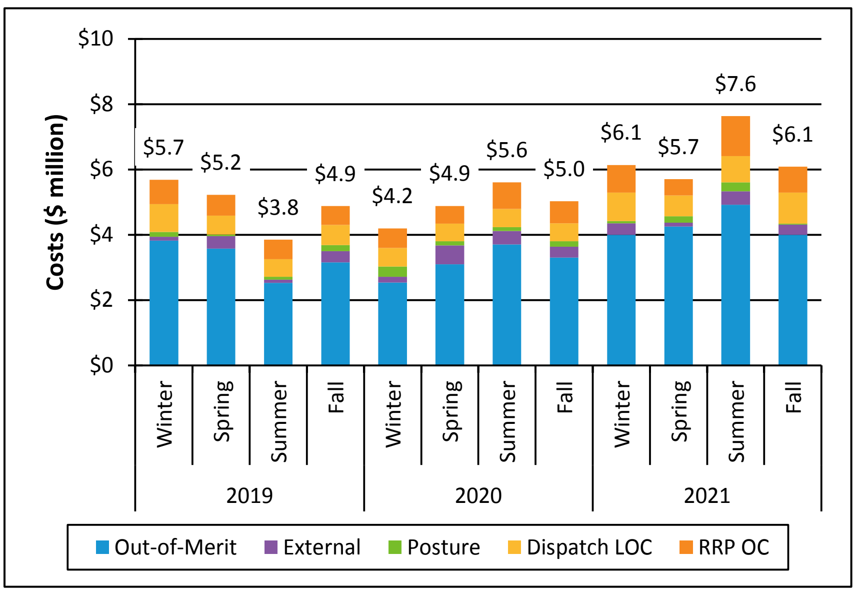
the Boston area and northern New England necessitated day-ahead reliability commitments. The majority (72%) of second contingency payments were paid out in October. Of the October payments, three natural gas-fired generators received a total of 65% or $0.6 million. The Boston import interface was constrained by a high voltage tranmission outage that was in effect the entire month of October. 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 (78% or $6.1 million) paid in Fall 2021, with 68% of total economic payments made in the real-time market. Economic payments increased by $1.1 million (21%) from Fall 2020 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[18]



[18] **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.

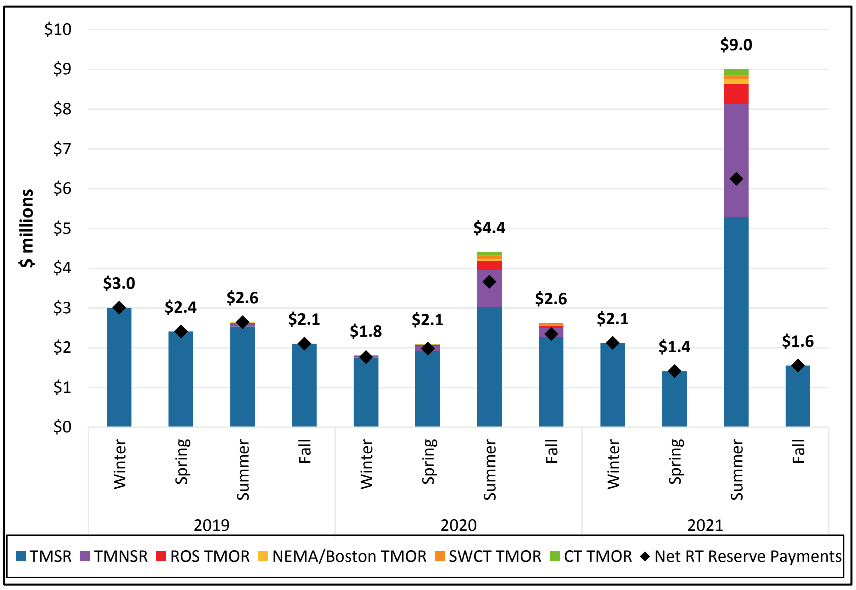
Out-of-merit payments, make up the majority of economic uplift (66%). These payments rose by $0.7 million (21%) in Fall 2021 compared to Fall 2020.

3.5 Real-Time Operating Reserves

Bulk power systems must be able to quickly respond to contingencies, such as the unexpected loss of a large generator. To ensure that adequate backup capacity is available, the ISO procures reserve products through the locational Forward Reserve Market (FRM) and the real-time energy market. 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 the reserve requirement.

Real-time reserve payments by product and by zone are illustrated in Figure 3-8 below. 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. Gross and net real-time reserve payments, which were $1.6 million in Fall 2021, are shown in Figure 3-8. The height of the bars indicate gross reserve payments while the black diamonds show net payments.

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



Fall 2021 reserve payments (gross) were down $1.1 million from Fall 2020. The reduction in payments is primarily due to lower payments for ten-minute spinning (TMSR). Both the average ten-minute spinning reserve (TMSR) price and the frequency of low TMSR margins decreased in Fall 2021 compared to Fall 2020 and 2019.

The absence of any non-spinning reserve pricing in Fall 2021 is another reason for the decline. A pumped-storage generator returned from long-term outage, which increased the total offline reserves (TMNSR and TMOR) provided by all pumped storage generation by 14% (145 MW) compared to Fall 2021. This corresponds with the small increase in offline reserve margins in Fall 2021 compared to Fall 2020.

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.[19]

Table 3-1: Hours and Level of Non-Zero Reserve Pricing[20]

Product	Zone	Fall 2021		Fall 2020		Fall 2019	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$7.35	350.5	$7.84	467.2	$9.60	363.8
TMNSR	System	$0.00	.	$94.68	2.1	$0.00	.
TMOR	System	$0.00	.	$93.19	1.5	$0.00	.
	NEMA/Boston	$0.00	.	$93.19	1.5	$0.00	.
	CT	$0.00	.	$93.19	1.5	$0.00	.
	SWCT	$0.00	.	$93.19	1.5	$0.00	.

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 351 hours (16% of total hours) during Fall 2021, which was 117 hours (25%) fewer than in Fall 2020. Since reserve prices reflect the cost to re-dispatch the system to meet the reserve requirement, reserve price trends typically follow energy prices based on energy market offers.

Due to the increase in gas (163%) and real-time energy prices (126%) in Fall 2021 compared to Fall 2020, slightly lower average TMSR pricing in Fall 2021 ($7.35/MW vs. $7.84/MWh) diverges from the trend of higher prices. Since there was less fixed supply (see Section 2.3 above), the system had more dispatchable generators online, which were able to provide more spinning reserves. This included an increase in gas-fired generation, and the aforementioned pumped-storage unit that returned from a long-term outage.

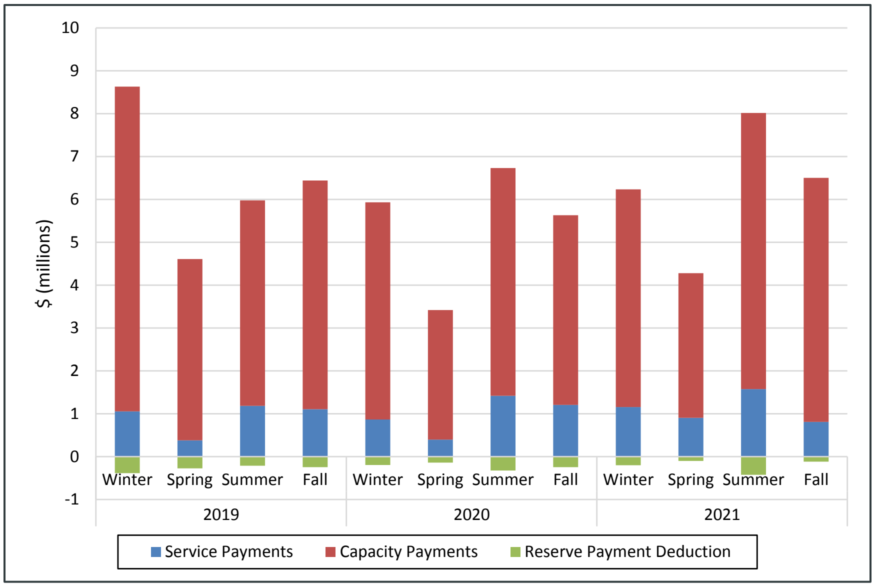
[19] Non-zero reserve pricing occurs when there is an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

[20] 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 125 minutes in Fall 2020. Therefore, the table shows the average system TMNSR price ($94.68) during these 125 minutes.

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

Figure 3-9: Regulation Payments



Total regulation market payments were $6.4 million during the reporting period, up approximately 19% from $5.4 million in Fall 2020, and down by 16% from $7.6 million in Summer 2021. The increase in payments compared to the prior fall period primarily reflects an increase in capacity prices and associated payments for regulation resources. The increase in capacity prices resulted from an increase in both energy market opportunity costs (reflecting increased LMPs in Fall 2021) and incremental cost savings. [22]

Committed regulation capacity did not change materially between the two periods and did not affect capacity payments, while a reduction in service prices and payments for Fall 2021 partially offset the increase in capacity payments.

Comparing Summer 2021 to Fall 2021, the reduction in total payments resulted from declines in both service and capacity payments. Service payments fell primary as result of reduced service prices, leading to an $0.8 million decline in payments. The decline in capacity payments reflects a reduction in manual commitment of regulation resources with high capacity price offers, comparing the two periods.

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

[22] 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
Forward Markets

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

4.1 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.[23] 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.[24] Between the initial auction and the commitment period, there are further opportunities to adjust annual Capacity Supply Obligations (CSOs) through annual and monthly reconfiguration auctions. Formerly, three of the annual auctions were bilateral auctions, where obligations were traded between resources at an agreed upon price and approved by the ISO. The other three were annual reconfiguration auctions run by the ISO, where participants submitted supply offers to take on obligations, or submitted demand bids to shed obligations. After June 1, 2019, the annual bilateral auctions were replaced with the incorporation of Annual Reconfiguration Transactions (ARTs) into the remaining three annual reconfiguration auctions.

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 reconfiguration auctions, participants can acquire or shed obligations. 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 current capacity commitment period (CCP) started on June 1, 2021 and ends on May 31, 2022. The conclusion of the corresponding Forward Capacity Auction (FCA 12) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 34,828 megawatts (MW) of capacity which exceeded the 33,725 MW Net Installed Capacity Requirement (Net ICR), at a clearing price $4.63/kW-month. The clearing price of $4.63/kW-month was 13% lower than the previous capacity period's $5.30/kW-month; two generators were retained for reliability in FCA 12, leading to a negative shift in clearing price as their 1,278 MW of capacity was entered into the auction at $0.00/kW-month. The $4.63/kW-month clearing price was applied to all capacity zones within New England. Price separation occurred at two import interfaces, Phase I/II and

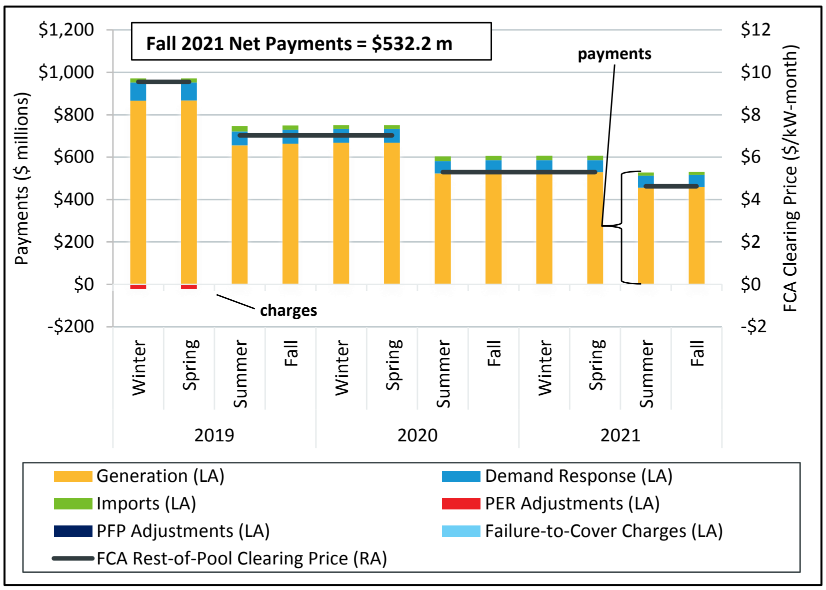
[23] In the capacity market, resource categories include generation, demand response and imports.

[24] 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.

New Brunswick, with final clearing prices of $3.70/kW-month and $3.16/kW-month, respectively. The results of FCA 12 led to an estimated total annual cost of $2.02 billion in capacity payments, $0.40 billion lower than capacity payments incurred in FCA 11.

Total FCM payments, as well as the clearing prices for Winter 2019 through Fall 2021, are shown in Figure 4-1 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[25]. The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 4-1: Capacity Payments



Net FCM payments totaled $532.2 million in Fall 2021, a decrease of $71 million (12%) from Fall 2020 payments (accounting for adjustments to primary auction CSOs).[26] A 13% decrease in the capacity clearing price ($5.30 in Fall 2020 to $4.63 in Fall 2021) is the driver of lower payments.

In Fall 2021, there were just over $0.15 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to offer up to its CSO in the energy market. 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.

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

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

[26] 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.

and bilateral trading activity during Fall 2021 alongside the results of the relevant primary FCA are detailed in Table 4-1 below.

Table 4-1: 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	Phase I/II	Highgate	New Brunswick
FCA 12 (2021-2022)	Primary	12-month	4.63	34,828	3.70		3.16
	Monthly Reconfiguration	Nov-21	1.00	652		0.55	0.55
	Monthly Bilateral	Nov-21	3.89	7			
	Monthly Reconfiguration	Dec-21	1.91	813			
	Monthly Bilateral	Dec-21	2.22	42			
	Monthly Reconfiguration	Jan-22	3.55	728		1.20	1.20
	Monthly Bilateral	Jan-22	3.39	358			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions took place in Fall 2021: the November 2021 auction in September, the December 2021 auction in October, and the January 2022 auction in November. Clearing prices trended upwards over the three auctions; beginning at $1.00/kW-month in November and increasing to $1.91/kW-month in December and $3.55/kW-month in January. Despite rising clearing prices, cleared MW volumes remained relatively constant for all three auctions. The December auction cleared the largest volume at 813 MW, followed by the January auction at 728 MW, and the November auction at 652 MW.

4.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market. 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:[27]

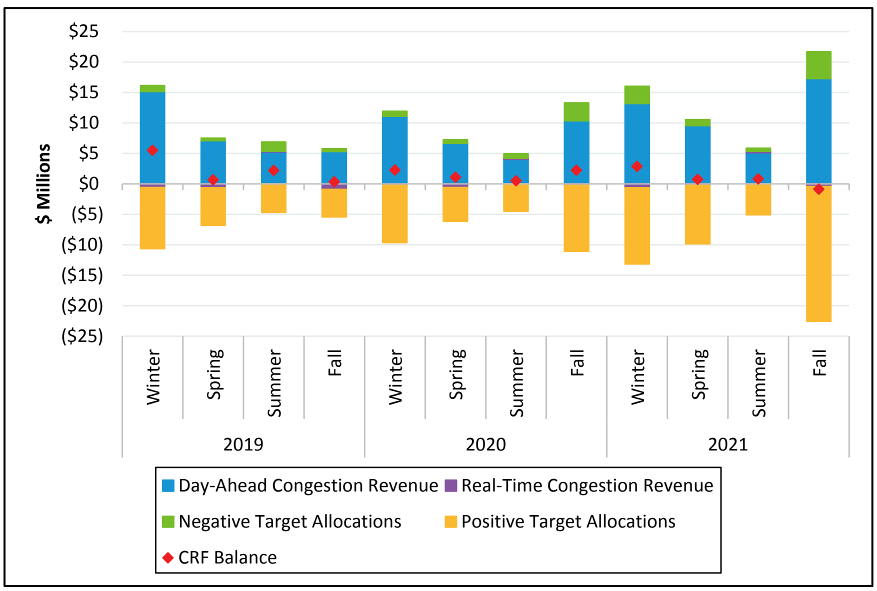
[27] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location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

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 4-2 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.[28] 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.

Figure 4-2: Congestion Revenue and Target Allocations by Quarter



By several measures, Fall 2021 experienced the most transmission-related congestion of any quarter covered in the reporting period. Day-ahead congestion revenue, positive target

[28] The CRF balances depicted in Figure 4-2 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.

allocations, and negative target allocations all reached their most extreme values over the last 12 quarters. Day-ahead congestion revenue amounted to $17.3 million in Fall 2021. This represents an increase of 239% relative to Summer 2021 ($5.1 million) and an increase of 67% relative to Fall 2020 ($10.3 million). Positive target allocations in Fall 2021 ($22.1 million) followed a similar pattern, increasing by 336% relative to Summer 2021 ($5.1 million) and increasing by 104% from Fall 2020 ($10.8 million). Similarly, there were elevated levels of negative target allocations in Fall 2021 (-$4.4 million) compared to both Summer 2021 (-$0.5 million) and to Fall 2020 (-$2.9 million). Meanwhile, real-time congestion revenue in Fall 2021 (-$0.4 million) remained relatively modest and was generally in-line with levels from Summer 2021 ($0.2 million) and Fall 2021 (-$0.2 million).

Transmission work contributed to the congestion that materialized in Fall 2021. 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 in the area near the affected transmission element and also change the flow of power in ways the bulk transmission system may not have been designed for. Several of the more impactful transmission constraints in Fall 2021 are listed below. The description attached to each constraint contains a summary of the constraint's function as well as some insight into why it experienced congestion in the quarter.

- **Keene Road Export (KR-EXP)**: This interface is used to manage the power flows from an area in eastern Maine that has a high concentration of intermittent generators. An extended transmission outage reduced the capability of this interface for much of Fall 2021, leading to frequent congestion in both the day-ahead and real-time energy markets.
- **Orrington – South (ORR-SO)**: This interface is used to manage the flow of power from eastern Maine and New Brunswick to the rest of the system. This constraint bound frequently in the day-ahead and real-time energy markets during the middle part of October when a nearby 345-kV line was taken out of service for structure replacement. This outage reduced the transfer capability of this interface, leading it to bind more frequently over the period of the outage.
- **New England West-East (NE_WE)**: This interface is used to manage power flows from western New England to eastern New England. While the two interfaces listed above are relatively localized, this interface essentially splits New England into two halves. Consequently, when this interface is congested, it can meaningfully impact the target allocations for a large volume of FTRs. This interface bound periodically in the day-ahead energy market in Fall 2021, partly as a result of transmission work that reduced the limit of this interface at various points over the three months.

While FTRs were fully funded in September 2021, they were not in October 2021 nor November 2021. In October 2021 only 89.7% of positive target allocations were funded ($8.8 million of the $9.9 million due). Similarly, November 2021 had a 93.6% funding rate (only $7.5 million of the $8.0 million due). One of the major drivers for the underfunding of FTRs during these two months was the above-mentioned transmission work that limited the Keene Road Export (KR-EXP) interface. One way underfunding can occur is when the limit used on a transmission element in an FTR auction exceeds the value used in the day-ahead market, allowing more FTRs to be awarded in an FTR auction than can be supported financially in the day-ahead market. This is what happened with the KR-EXP interface in October and much of November. In total, there was an underfunding of $0.9 million for the months comprising Fall 2021.

However, at the end of November 2021, there was a congestion revenue fund surplus of $3.4 million for 2021. As mentioned above, surpluses like this carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.

Section 5
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. This section 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, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM's reference level.

5.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the real-time market using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI). Both of these widely-used metrics identify instances when the largest supplier has market power[29]. 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 supplier. 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[30] to the sum of each participant's total supply that is available within 30 minutes.[31] When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute pricing intervals with at least one pivotal supplier are divided by the total number of five-minute pricing 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 5-1 below.

[29] 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.

[30] 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*]

[31] 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 5-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2019	106.3	11%
Spring 2019	107.5	8%
Summer 2019	106.7	18%
Fall 2019	104.8	21%
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%

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 in recent quarters, ranging from 8% to 27% in 2021. There were higher frequencies of pivotal suppliers in Summer 2020 and 2021, which saw relatively high loads, and in Fall 2020 and 2021, when several baseload generators had scheduled outages for planned maintenance, inspections, or refueling.

Though Fall 2020 and Fall 2021 both saw similar frequencies of pivotal suppliers, Fall 2021 saw higher loads and even more outages than in Fall 2020. However, as a result of lower amounts of fixed generation from baseload generators and net imports, there was more dispatchable generation online in Fall 2021, leading to higher supply margins and fewer instances of tight system conditions. These effects counteracted one another, resulting in the similar pivotal supplier frequency values during both fall periods. The high RSI values and the low frequency of pivotal suppliers indicate that there were limited opportunities for any one supplier to exercise market power over the last twelve quarters.

5.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[32] 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

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

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.[33] These circumstances are summarized in Table 5-2 below.

Table 5-2: 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.[34] 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).[35] 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).[36] This test only applies to general threshold energy and constrained area energy mitigation types.

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

[34] 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.

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

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

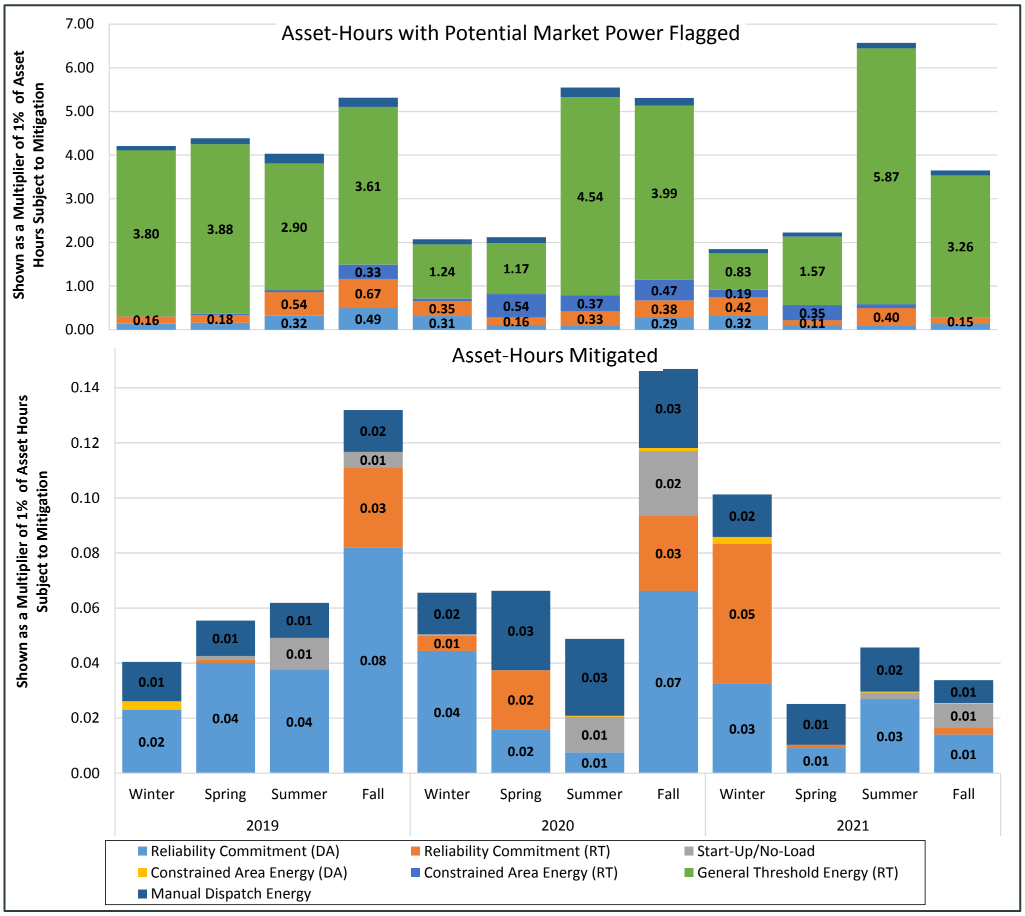
Energy Market Mitigation Frequency

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 5-1 below.[37] 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.

[37] 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, SUNL commitment hours are not shown because mitigation hours equal commitment hours.

Figure 5-1: Energy Market Mitigation[38]



On average, approximately 300,000 asset-hours of ISO-committed generation are subject to the IMM's mitigation rules. In Fall 2021, the total asset-hours reached 314,000, with approximately 11,000 asset-hours (4%) failing structural tests and approximately 3,140 asset-hours (1%) subject to mitigation by the IMM. Mitigation asset-hours represent a very small fraction of potential asset hours subject to mitigation. In the figure, day-ahead reliability commitment mitigation totaled just 44 asset-hours for Fall 2021, equaling 0.01 of asset-hours scaled to 1% (i.e., 44/3140).

In general, the data in Figure 5-1 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). The highest frequency of mitigation occurs for reliability commitments (light blue or orange shading); this results 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 threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue, and yellow

[38] 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.

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).[39] 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, 41% and 38% 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. Reliability commitment mitigations also occurred most frequently in Maine and SEMA-RI: 42% of mitigations occurred in Maine and 40% occurred in SEMA-RI in the day-ahead market.[40] Overall, reliability mitigations declined significantly between Fall 2020 (185 asset-hours) and Fall 2021 (44 asset-hours). This decrease resulted from both a decline in reliability commitment asset-hours (decline from 634 to 262 asset-hours) and of mitigated offers in Maine and SEMA-RI (decline of 129 to 32 asset-hours).

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).[41] 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 two participants accounted for 90% of these mitigations. There were just 27 asset-hours of SUNL mitigation in Fall 2021.

Constrained area energy (CAE) mitigation:[42] 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 no CAE mitigation has occurred in the real-time energy market and only 23 asset-hours of mitigation have occurred in the day-ahead energy market. The frequency of structural test failures follows the incidence of

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[39] 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.

[40] 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.

[41] 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.

[42] 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.

transmission congestion and import-constrained areas within New England. Most of the failures occurred in 2020 (57%); the 2020 failures were spread throughout New England, with 23% in Connecticut, 15% in Western and Central Massachusetts, 9% to 12% frequency occurring in every other load zone. Transmission work in SEMA-RI and Maine contributed to the higher frequency of transmission congestion in 2020. In Fall 2021, there were very few hours of structural test failures (30 asset-hours), and there was only one asset-hour of constrained area energy mitigation. For comparison, there were 293 asset-hours of structural test failures in Summer 2021 and 1 asset-hour of mitigation.

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 60% of the structural test failures and four participants accounted for 72% of structural test failures over the review period. The frequency of pivotal supplier asset-hours decreased slightly in Fall 2021 (by 8%), compared to Fall 2020.

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 5-1, 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 2021, there were 342 asset-hours of manual dispatch and 26 asset-hours of mitigation. Summer 2021 experienced more asset-hours of manual dispatch (405) and more asset-hours of manual dispatch mitigation (52). Compared to Fall 2020, manual dispatch asset-hours declined by 30% in Fall 2021, and mitigation asset-hours declined by 68%.