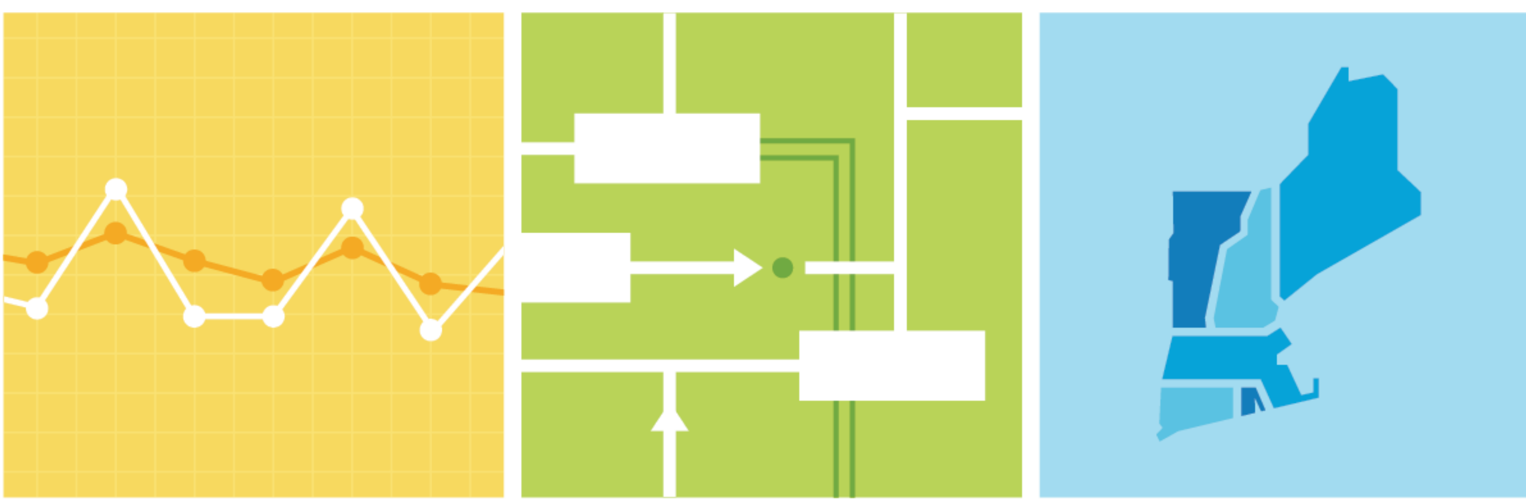
Winter 2022
Quarterly Markets Report

By ISO New England's Internal Market Monitor

MAY 4, 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 Winter 2022 (December 1, 2021 through February 28, 2022).[3]

Overview of Winter 2022: Winter 2022 saw the highest natural gas prices and LMPs since Winter 2014. While there was no distinct "cold snap" period of extreme low temperatures, average temperatures were 4°F colder in January 2022 compared to January 2021. Natural gas prices remained high for several long periods, particularly in January, and oil generation was in-merit more frequently than in the past several winters.

Below are highlights of system events, supply mix, marginal units, fuel markets, and fuel oil supplies:

- Two Master Local Control Center Procedure No. 2 (M/LCC 2) events occurred during Winter 2022. The first event was declared on January 11 due to an imminent capacity deficiency. The second M/LCC2 event of the quarter was declared from January 28-30 due to severe weather, when Winter Storm Kenan brought heavy snowfall to the region.
- Most Winter 2022 oil-fired generator commitments occurred when gas prices were above \$20/MMBtu (38% of hours). Over all hours, oil generation made up 4% of total generation, or 584 MW per hour, on average.
- Most fuel oil generation over the winter period occurred during the latter half of January, when natural gas prices were significantly higher than fuel oil prices.
- Periods where gas prices exceeded oil prices led to generators operating on oil setting price more frequently. Dual-fuel units set price more frequently in Winter 2022 (33% of load) than in Winter 2021 (25% of load). Oil-only generators set price for 3% of load in the real-time market.
- The high gas prices did not lead to any significant reliability impacts for the ISO, as generator reductions from failures to obtain gas and generator limitations resulting from gas pressure issues were relatively rare.
- In general, generators' oil supplies were sufficient to replace gas generation during periods of tight gas supplies. Fuel switching occurred consistent with energy market incentives.
- The number of fuel price adjustment (FPA[4]) requests this winter remained similar to last winter at around 3,500. On average, approximately 74% of FPA requests were approved over the last three winter periods.
- Other than the capacity commitments during the first MLCC/2 event, and LSCPR commitments for the West-East constraint, there were minimal manual resource commitments during Winter 2022. Additionally, operators only postured pumped-storage units during the Winter.

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

[4] Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index.

Energy Market Opportunity Costs: Beginning in December 2018, Energy Market Opportunity Cost (EMOC) adders for oil-fired generators have been included in energy market reference levels. The EMOC adder is designed to allow generators to reflect their expected value of limited production capability in supply offers. Consequently, oil-fired generators should be dispatched when most needed, reducing the need for operators to manually intervene in the market by posturing resources.[5] Generally, we expect to see EMOCs when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to physically exhaust their oil inventory within a seven-day horizon.

During Winter 2022:

- Prolonged periods of higher natural gas prices were highly correlated with occurrences of EMOC adders.
- Throughout the quarter, eighteen generators received EMOC adders for their oil inventories in both the day-ahead and real-time markets.
    - Thirteen of the assets were dual-fuel capable while the remaining five generate on oil only.
    - The EMOC adders were split across 34 days and 18 different generators in the day-ahead market, averaging around \$19/MWh. In the real-time market, EMOC adders were updated for 28 of those days, across 8 different assets, and averaged around \$18/MWh.
    - The second half of January 2022 saw the largest count of non-zero EMOC adders, with 15 generators affected on January 20 and 21.
- The IMM surveyed certain participants on their use of EMOC adders over the winter. Their responses indicated that the EMOC adder did not play a significant role in the development of their offers over the winter because they were confident they could secure fuel when needed.

The Sixteenth Forward Capacity Auction (FCA16): The sixteenth Forward Capacity Auction (FCA 16) was held in February 2022 and covers the capacity commitment period (CCP) beginning June 1, 2025 through May 31, 2026. Below are the highlights from the auction:

- There was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (NICR).
    - Qualified capacity (37,630 MW) exceeded the Net Installed Capacity Requirement (31,645 MW) by 5,985 MW. The surplus decreased from FCA 15 (7,269 MW) as a result of a sharp decline in qualified capacity of 2,909 MW year-over-year.
    - System-wide surplus capacity cleared 1,165 MW above NICR.
- Varying capacity amounts in import- and export-constrained zones led to three levels of price separation:
    - Southeastern New England at \$2.61/kW-month (fourth round).
    - Rest-of-Pool at \$2.59/kW-month (fourth round).
    - Northern New England at \$2.53/kW-month (fourth round).
- Payments for FCA 16 (\$1.0 billion) decreased by 21% compared to FCA 15, driven by lower clearing prices in the Rest-of-Pool and Southeastern New England capacity zones and less capacity supply obligations system wide.
- Considering pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 16.

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[5] A resource is postured when it is directed to operate below its economic dispatch point for reliability reasons.

- A total of 1,540 MW dynamically de-listed in FCA 16, including 780 MW of oil-fired generation, and 417 MW of gas-fired generation.
- New cleared capacity totaled 576 MW, primarily consisting of solar projects (209 MW), passive demand response (129 MW), and battery storage projects (102 MW).
- The substitution auction following FCA 16 did take place, however no demand bids or supply offers cleared against each other.

Wholesale Costs: The total estimated wholesale market cost of electricity was $4.28 billion, up 85% from $2.32 billion in Winter 2021. The increase was driven by higher energy costs in Winter 2022.

Energy costs totaled $3.73 billion; up 119% (or $2.03 billion) from Winter 2021 costs. Higher energy costs were a result of higher natural gas prices, which increased by 147% relative to Winter 2021 prices.

Capacity costs totaled $531 million, down 13% (by $76 million) over the previous Winter. 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 $110.34 and $105.48 per megawatt hour (MWh), respectively, a 115% and 104% increase compared to Winter 2021 prices.

- Natural gas prices averaged $14.41/MMBtu in Winter 2022, up 147% compared to $5.82/MMBtu during the prior Winter.
- Day-ahead and real-time energy prices continued to trend in the same direction as natural gas prices. However, due to high natural gas prices, oil generation was in merit more frequently in Winter 2022. This offset some of the upward pressure of higher gas prices on LMPs.
- Average real-time Hub prices were $4.86/MWh or 4% lower than average day-ahead prices. This difference resulted from several days throughout the quarter that saw significantly lower real-time LMPs. Factors that led to lower LMPs on these days included additional real-time renewable generation, less generation needed in real-time compared to the day-ahead cleared amount, and increased price sensitivity when midday loads were low.
- Energy market prices did not differ significantly among the load zones. Prices were slightly lower (3%) in Connecticut, a trend that has appeared in recent years, due to the combined effect of newer highly efficient natural gas-fired generators in the load zone, and transmission limitations on the export of relatively cheaper power to the rest of the system.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $13.7 million, a 42% increase compared to Winter 2021 payments of $9.7 million. Despite the increase, NCPC payments represented less than 1% of total wholesale energy costs in both Winter 2022 and Winter 2021. The majority of NCPC (81%) was in the economic category, which includes payments to resources providing first-contingency protection and payments to resources operating below their economic dispatch point at the instruction of the ISO. Most economic payments occurred in the real-time market.

At $2.6 million, local second-contingency protection (LSCPR) payments accounted for 19% of total NCPC payments. These payments decreased by $0.5 million relative to Winter 2021. Most LSCPR payments (90%) were made in December 2021, when generators were committed in the day-ahead market to meet reliability needs in Maine, New Hampshire and SEMA/Rhode Island due to planned transmission outages and binding transmission constraints.

Real-time Reserves: Real-time reserve payments totaled $2.1 million, a nearly identical total to that of Winter 2021. All reserve payments were for ten-minute spinning reserve (TMSR).

The average non-zero hourly spinning reserve price increased relative to Winter 2021, from $9.75 to $16.24/MWh. The increase was due to higher LMPs, which increased re-dispatch costs to provide reserves rather than energy. However, non-zero reserve pricing occurred less frequently in Winter 2022 compared to Winter 2021. The effects of higher reserve prices and lower pricing frequency offset one another.

***Regulation*:** Total regulation market payments were $11.2 million, up 85% from $6.0 million in Winter 2021. The increase in payments was due to higher energy market LMPs during Winter 2022, which led to higher regulation capacity prices.

Financial Transmission Rights: Winter 2022 experienced the most transmission-related congestion of any quarter covered in the reporting period. The New York-New England interface bound frequently in all three months of Winter 2022 even though it was at full operational capability for most of the quarter. The New England West-East interface bound periodically in the day-ahead energy market throughout Winter 2022, but most notably in December 2021 when transmission work reduced the interface limit. Day-ahead congestion revenue ($23.5 million), positive target allocations ($22.8 million), and negative target allocations (-$6.9 million) all reached the largest values of the last nine quarters. Meanwhile, real-time congestion revenue in Winter 2022 ($1.2 million) remained relatively modest and was similar to that of the previous winter.

FTRs were fully funded in December 2021, January 2022, and February 2022. At the end of February 2022, the congestion revenue fund had a surplus of $3.4 million.

Section 2
Assessment of Winter 2022 Market Issues

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

2.1 Overview of Winter 2021/22

Winter 2022 saw the highest natural gas prices and LMPs since Winter 2014. While there was no distinct "cold snap" period of extreme low temperatures, average temperatures were 4°F colder in January 2022 compared to January 2021. Daily average natural-gas prices exceeded $20/MMBtu on 32 days in the reporting period (most of which occurred in January); gas index prices did not exceed $20 on any day in Winter 2021. As a result, oil generation was in-merit more frequently than in the past several winters. Oil generation averaged 584 MW per hour in Winter 2022, compared to just 70 MW per hour in Winter 2021.

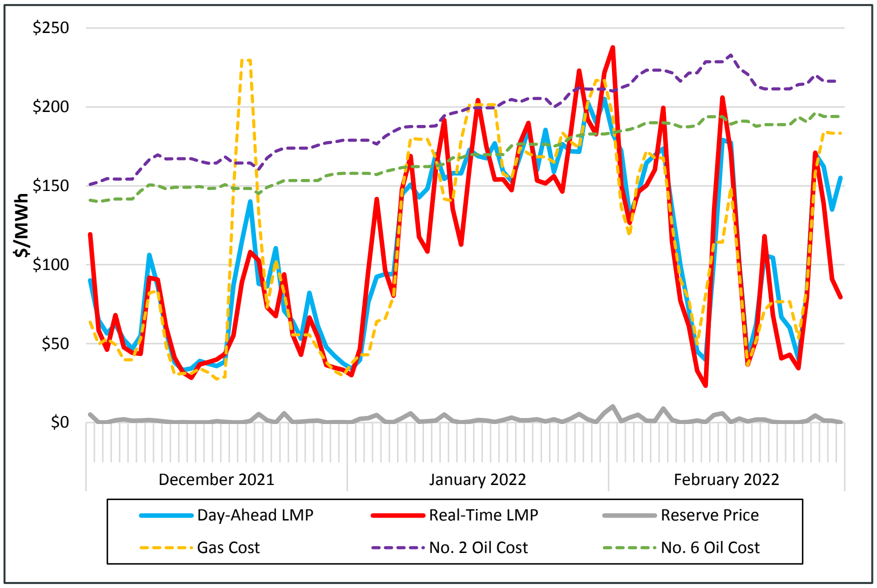
Additionally, two Master Local Control Center Procedure No. 2 (M/LCC 2)[6] events occurred during Winter 2022. The first M/LCC 2 event was declared on January 11 due to an imminent capacity deficiency. The Phase II interconnection with Hydro Quebec partially tripped at 12:28pm, resulting in a loss of 650 MW. Also, several generators tripped due to mechanical issues, and were unable to fulfill their day-ahead schedules. These unplanned transmission and generator outages necessitated additional generator commitments in real-time. The Phase II interconnection returned to service later that day. The second M/LCC 2 event was declared from January 28-30 due to severe weather. Winter Storm Kenan brought heavy snowfall to the region. Customer outages peaked at approximately 125,000 customers on January 29, which had little effect on total system load.[7] Transmission and generator outages were also minimal. considering the storm conditions, and did not result in reliability issues or significant pricing outcomes. These events are discussed in more detail in Section 2.6 below.

Figure 2-1 below shows daily average Hub LMPs, real-time reserve prices, and natural gas generation costs for Winter 2022. The natural gas generation costs are based on the daily average natural gas price and a generator heat rate of 7,800 Btu/kWh.

[6] M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability.

[7] There are a total of 7.2 million retail electricity customers in New England. See https://www.iso-ne.com/about/key-stats/

Figure 2-1: Daily Average Hub LMP, Reserve Price, and Natural Gas Generation Costs



Compared to Winter 2021, Winter 2022 saw colder weather in January and decreased liquefied natural gas (LNG) injections. In addition, there were tighter natural gas system conditions throughout the country, and natural gas storage levels were low at the start of the heating season.[8] Combined, these factors led to a 147% increase in Winter 2022 natural gas prices compared to Winter 2021. The highest daily natural gas price ($29.42/MMBtu) occurred on December 19-20, when temperatures reached a low of 17°F. Twenty-one of the 32 days with gas prices exceeding $20/MMBtu occurred in January 2022.

Day-ahead and real-time Hub LMPs averaged $110.34 and $105.48/MWh in Winter 2022, respectively, a 104-115% increase compared to Winter 2021. The effect of high natural gas prices on LMPs was partially offset by an increase in oil generation. Oil generators were in-merit more frequently in Winter 2022, setting price for 9% of real-time load compared to 1% in Winter 2021. Most Winter 2022 oil-fired generator commitments occurred when gas prices were above $20/MMBtu. High LMPs generally occurred on days with high natural gas prices. Hourly day-ahead Hub LMPs peaked at $276.04/MWh on February 1, while hourly real-time prices peaked at $351.31/MWh on January 31.

[8] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/01_06/

2.2 Supply by Fuel Type and Marginal Resources

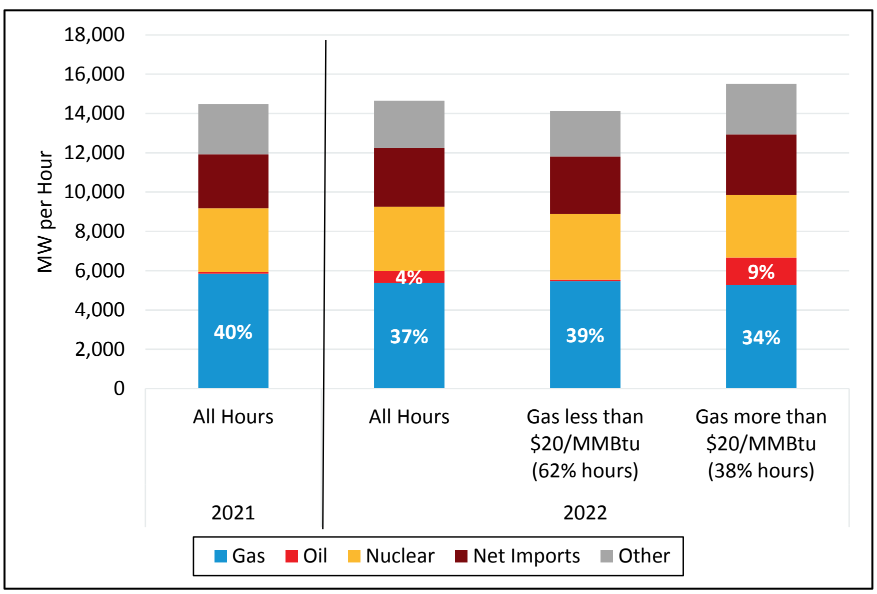
In New England, tight winter natural gas supplies can lead to reliability concerns for the delivery of wholesale electricity. Such concerns led the ISO to implement and maintain a Winter Reliability Program (WRP) for five winter periods in the past (i.e., Winters 2013-14 to 2017-18). The WRP provided financial inducements for participants to maintain alternative fuel supplies (primarily focused on inventories of fuel oil and LNG); the availability of the alternative fuels for generating electricity provided a reliability backstop, should limited natural gas supplies decrease gas-fired generator availability.

Since the discontinuation of the WRP, the ISO has continued to monitor the availability of generators' fuel oil supplies, and works with the natural gas pipelines in New England to understand potential gas system issues that might limit generators' operation. For Winter 2022, the New England region experienced cold temperatures and high natural gas prices intermittently from December to February. The high gas prices (signaling tight supplies) did not lead to any significant reliability impacts for the ISO, as generator reductions from failures to obtain gas and generator limitations resulting from gas pressure issues were relatively rare.

Supply Mix

Gas prices heavily influenced the supply mix during Winter 2022. Figure 2-2 illustrates average supply per hour by fuel type for Winter 2021 and Winter 2022. Winter 2022 is broken down into hours where the gas price was above and below $20/MMBtu. The bar's height represents average electricity generation, while the percentages represent percent share of generation from each fuel type.

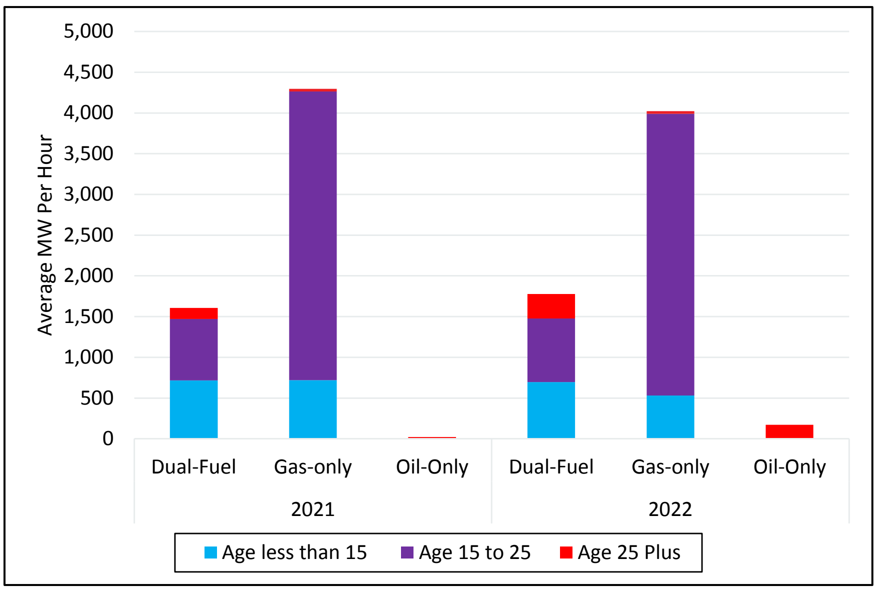
Figure 2-2: Generation by Fuel Type Separated by Gas Prices



Notes: "Other" category includes pumped storage, wind, solar, coal, hydro, battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

Most Winter 2022 oil-fired generator commitments occurred when gas prices were above $20/MMBtu (38% of hours). Otherwise, the fuel mix during Winter 2022 was similar to Winter 2021. Oil-fired generation accounted for 9% of total generation when gas prices were high, or 1,397 MW per hour, on average. When gas prices were lower than $20/MMBtu in Winter 2022 (62% of hours), that hourly average fell to 77 MW. This is similar to the 70 MW per hour average in Winter 2021, when gas prices never exceeded $20/MMBtu. Over all hours oil generation accounted for 4% of total generation, or 584 MW per hour, on average. Of that, 411 MW (70%) came from dual-fuel units, and 173 MW (30%) came from older, less efficient oil-only generators. A breakdown of these units by age is shown in Figure 2-3 below.

Figure 2-3: Gas, oil, and dual-fuel generation by age, Winter 2022

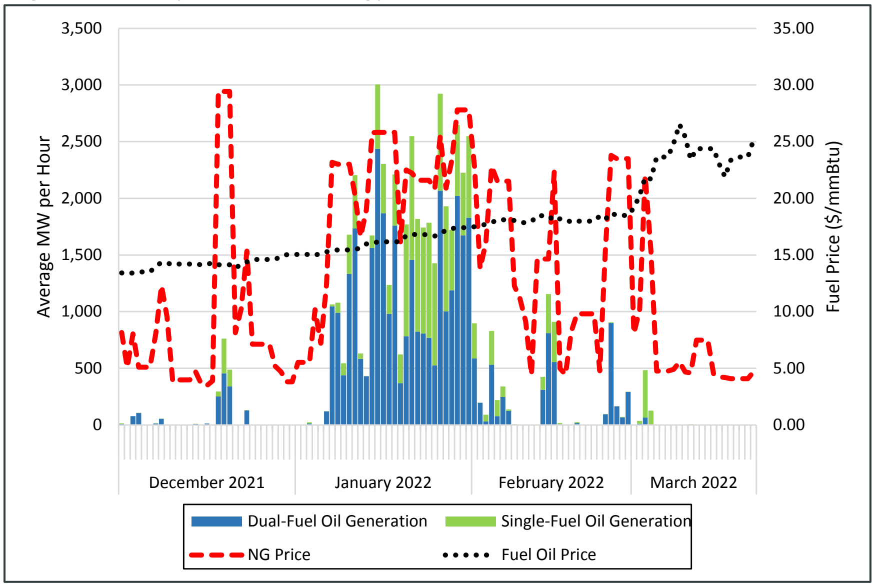


With higher natural gas prices in Winter 2022, older dual-fuel and oil-only units were more frequently in merit when compared with Winter 2021.

Fuel Oil Supply and Generation

High natural gas prices led to increased oil generation during Winter 2022. In general, throughout the winter period, generators' oil supplies were sufficient to replace gas generation during periods of tight gas supplies. This fuel switching occurred consistent with energy market incentives, as dual-fuel generators chose to operate on fuel oil when that was the cheapest fuel source and oil-only generators became "in-merit" for providing generation. Figure 2-4 indicates fuel-oil generation by day, relative to the prices for natural gas and fuel oil.[9]

Figure 2-4: Daily Real-Time Energy Market Fuel Oil Generation and Fuel Prices



On days when fuel oil prices were significantly below gas prices, fuel oil generation partially displaced gas generation. The bulk of winter fuel oil generation occurred during the latter half of January, when natural gas prices were significantly higher than fuel oil prices (natural gas prices averaged $24/MMBtu and fuel oil prices averaged $17/MMBtu). Over this period, oil-fired generation averaged approximately 2,000 MW per hour.[10] Natural gas prices declined significantly in February, and fuel oil generation was in-merit for only short periods during the month. Overall, there were 30 days during the winter period when average hourly generation from fuel oil was greater than 500 MW per hour and 22 days when fuel oil generation exceeded 1,000 MW per hour on average.

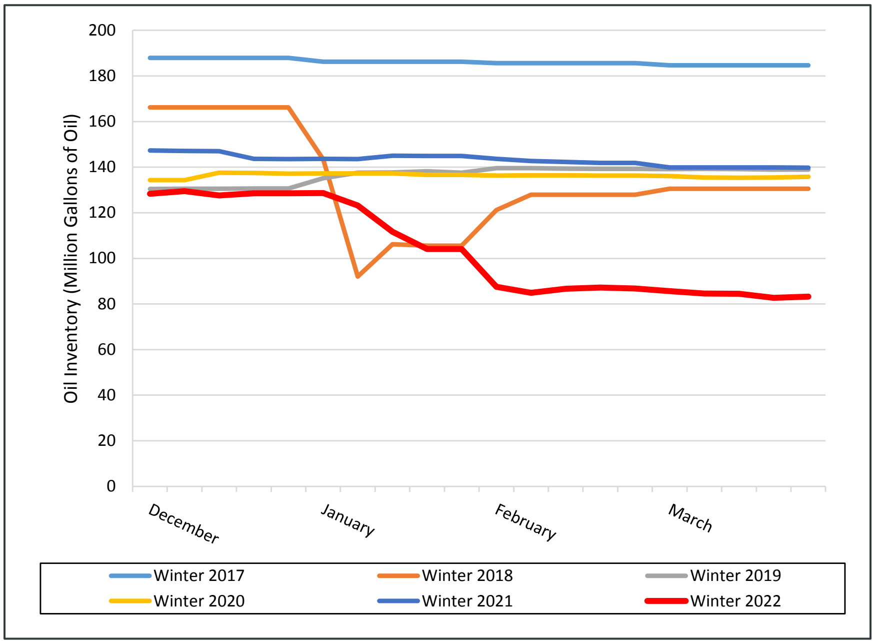
Figure 2-5 shows fuel oil inventories for generators over the past six winter periods. [11]

[9] The fuel oil generation data (MWh) are estimates based on the indicated fuel blends included in generator supply offers. The fuel oil price, provided for illustrative purposes, is for Fuel Oil No. 6.

[10] Two thousand megawatts per hour represents approximately 14% of the average hourly load for Winter 2022.

[11] Because the inventory data correspond to a particular month and day, the values have been adjusted to reflect weekly values. For example, inventory values reported in week 1 of January are shown as the first weekly inventory value, values in reported in week 2 are shown as the second weekly inventory value, etc. If only one inventory value was available for a month, then that value is repeated as each week's inventory during the month.

Figure 2-5: Winter Period Fuel Oil Inventories



During January 2022, oil inventories (red line) declined significantly as generators burned oil.[12] Compared to beginning inventory levels, oil inventories declined by 32% by the first week in February. Winter 2022 also began with the lowest starting oil inventory of the six periods reviewed. The 2022 starting inventory levels were lower by approximately 13% compared to Winter 2021, lower by 23% compared to Winter 2018, and lower by 32% compared to Winter 2017.[13] Winter 2022 had starting inventories just slightly below the starting levels for Winters 2019 (2%) and 2020 (4%). During the six winter periods, only Winters 2022 and 2018 had significantly depleted oil supplies. For each period, prolonged cold weather, tight gas supplies and high gas prices resulted in significant use of fuel oil.

Fuel Switching

During Winter 2022, gas was more expensive than heavy and light fuel oil on 38 days, compared to just four days in Winter 2021. When both gas and oil are available to dual-fuel generators, they are expected to offer on the cheaper fuel. Not doing so could be considered economic withholding, since higher offers prices could cause an otherwise in-merit generator to not clear. Typically, this means dual-fuel generators offer on gas. However, during Winter 2022,

[12] For fuel supplies, data are provided for December through March, when cold temperatures are most likely to affect fuel supplies and prices. The winter periods in this section are identified using the year associated with the January-March months in the period: for example, the December 2021 – March 2022 period is referred to as Winter 2022.

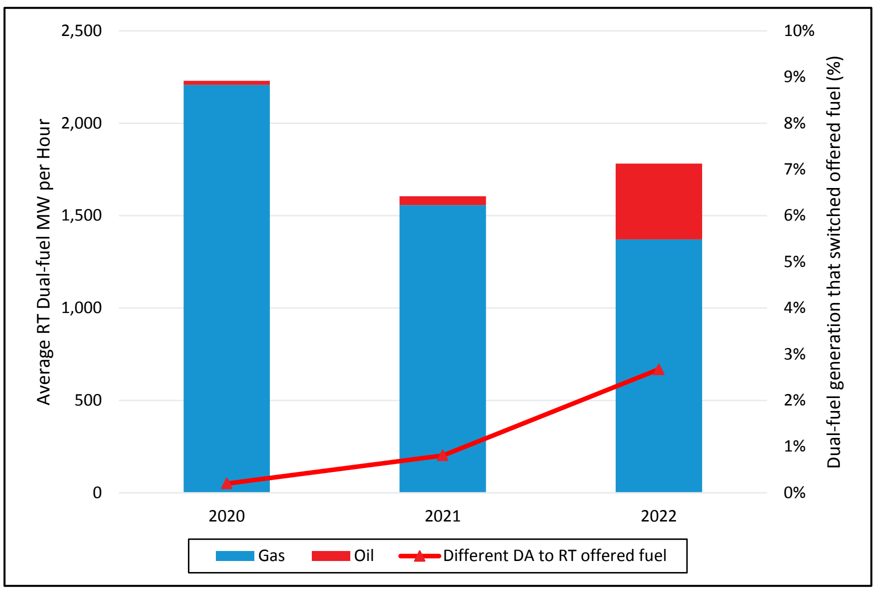
[13] The noticeably higher starting inventory levels in winters 2017 and 2018 correspond to the final two years of the WRP. Incentives associated with the WRP may explain why those years had the highest starting inventories levels during the six winter periods depicted in the figure.

gas and oil prices were much closer and gas procurement, particularly to cover unanticipated output after the timely nomination cycle, was uncertain and, at times, challenging. [14]

Section III.A.3.2 of the tariff specifies participants' responsibilities when they operate on a higher-priced fuel but have the ability to burn a lower priced fuel. Participants must "provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel [and] provide the Internal Market Monitor with evidence that the higher cost fuel was used." There is an exception, however, when gas and oil prices converge; specifically, when the ratio of the higher priced fuel to the lower prices fuel is below 1.75, participants do not need to provide justification for burning the higher priced fuel. This exception was designed to recognize the challenges of procuring gas as prices converge around the price of oil, and removed disincentives to procure the cheaper fuel if it did become available for real-time use.

For example, if oil prices were $25/MMBtu, then units who cleared in the day-ahead on oil would need to justify operating on oil if gas prices were lower than $14.29/MMBtu ($25/$14.29 = 1.75). In Winter 2022, the ratio was within 1.75 in 58% of hours, compared to just 32% in Winter 2021. Figure 2-6 shows the amount of dual-fuel capable real-time generation in Winter 2020 to Winter 2022. The line illustrates the amount of generation that switched offered fuel between the day-ahead and real-time markets.[15]

Figure 2-6: Dual-fuel Generation and Fuel Switching



The graph clearly shows that dual-fuel generators burned more oil in Winter 2022 compared to previous years. This was expected, as oil generation increased, and dual-fuel units have lower heat-rates than generators who operate on oil only. Dual-fuel generators switched their day-ahead and real-time offered fuel for roughly 3% of their total generation, or 48 MW per hour on

[14] The intraday gas cycle occurs after the timely nomination cycle. Gas is challenging to schedule during this period for two reasons. First, there is a risk of scheduling gas and later having those nominations curtailed; particularly on secondary paths. This risk is even greater during periods with operational flow orders. Second liquidity is lower after the timely nomination cycle. Gas procured past timely cycle will usually be at a higher premium while available gas can be limited.

[15] In a small number of hours, dual-fuel generators blended fuels. Those instances account for less than 0.1% of total fuel burned by dual-fuel generators.

average. This fuel switching is further broken down in Table 2-1 below that provides insight into the direction of fuel switching over the past three winters.

Table 2-1: Fuel Switching (MWs per Hour)

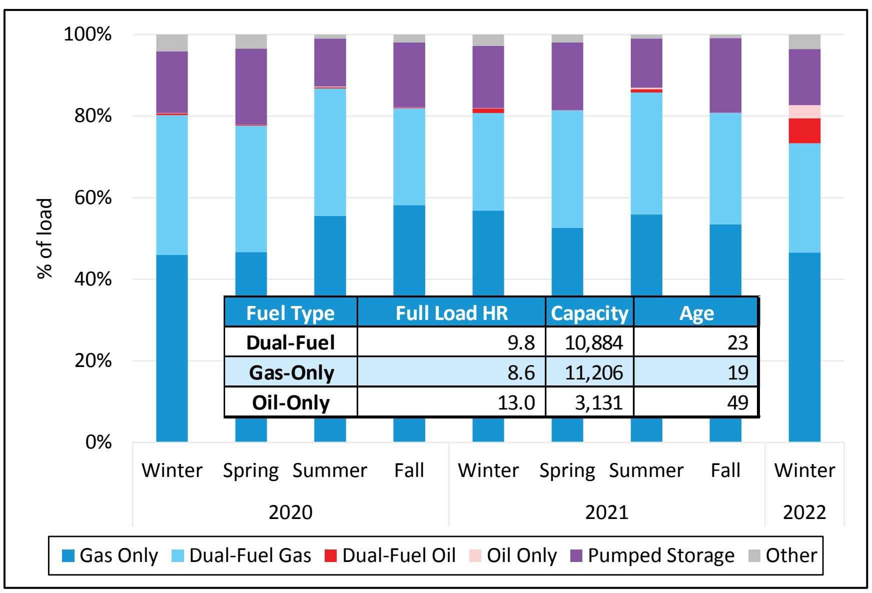
Winter	All Gas RT	All Oil RT	Switch to Gas RT	Switch to Oil RT
2020	2,208	23	2	2
2021	1,557	49	5	8
2022	1,371	411	37	10

While neither 2020 and 2021 show a strong directionality in switching, it is clear that in Winter 2022 dual-fuel units switched four times the MWs from oil to gas than they did from gas to oil. It is likely that some dual-fuel units offered on oil when DA gas was relatively expensive and then switched to natural gas if lower gas prices were realized in real-time.

Marginal Resources

Generators operating on oil set price for more load in Winter 2022 compared to Winter 2021 due to gas prices frequently exceeding oil prices. Figure 2-7 illustrates the percentage of load for which oil- and gas-fired generators set price in the real-time market based on whether the generators can only burn oil, only burn gas, or burn both (dual-fuel capable). The table within the graph summarizes the average heat rate, average age, and aggregated maximum capacity of generators within each category.[16]

Figure 2-7: Real-Time Marginal Generators by Fuel and Subtype



Note: "Other" category includes pumped storage, wind, solar, coal, hydro, battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

[16] This metric uses full load average heat rate. Full load average heat rate measures the units average heat rate based on their maximum net output.

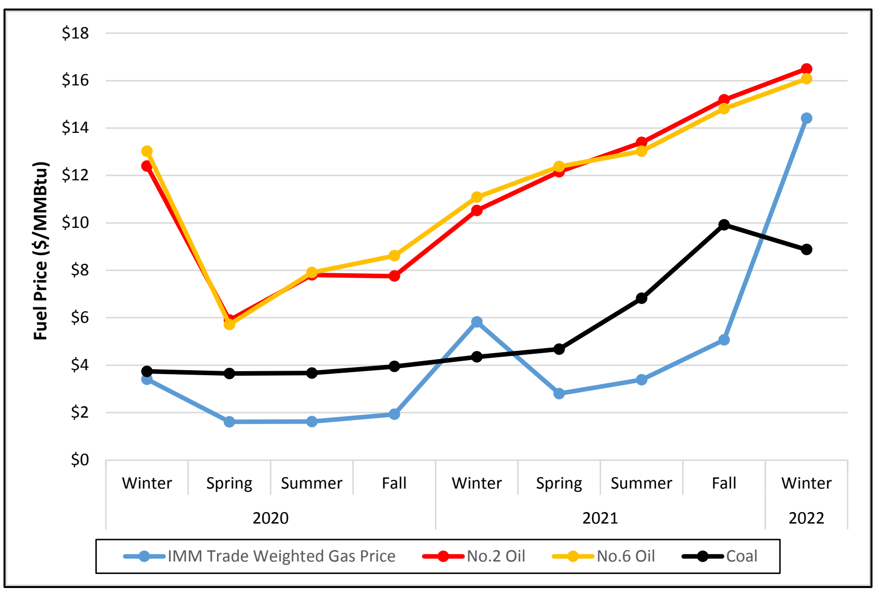
Dual-fuel generators, which tend to have higher heat rates than gas-only generators, set price more frequently in Winter 2022 (33% of load) than in Winter 2021 (25% of load). The key difference is that dual-fuel generators set price while offering on oil for 6% of load in Winter 2022. Oil-only generators, which have higher heat rates on average than dual-fuel generators, set price for just 3% of load in the real-time market. Gas-only generation, which is the most efficient of the three generator types on average, set price for 47% of load in Winter 2022, compared to 57% of load in Winter 2021, when gas prices were much lower.

2.3 Fuel Markets

During winter in New England, cold weather can cause natural gas pipelines to become constrained, giving rise to high natural gas prices. As temperatures fall, natural gas heating demand increases and natural gas-fired generators must compete for limited pipeline capacity. For instance, the cold snap in Winter 2018 led to constrained natural gas pipelines and gas prices reached a record daily high of nearly $62/MMBtu.[17] This pushed gas-fired generators up the supply stack and out of economic merit order. In Winter 2022, natural gas prices averaged $14.41/MMBtu, the highest average natural gas price since Winter 2014.

Fuel Prices: For the most part, New England's electricity prices are driven by fuel costs and the operating efficiency of combustion generators. Average quarterly prices for gas, coal and oil are shown in Figure 2-8 below.

Figure 2-8: Fuel Prices



In Winter 2022, average prices increased for all major fuels:

- Natural gas prices averaged $14.41/MMBtu, a 147% increase compared to Winter 2021 and the highest quarterly natural gas price since Winter 2014 ($19.34/MMBtu).
- Coal prices averaged $8.88/MMBtu, a 104% increase compared to Winter 2021 and the second highest quarterly price since at least 1999.

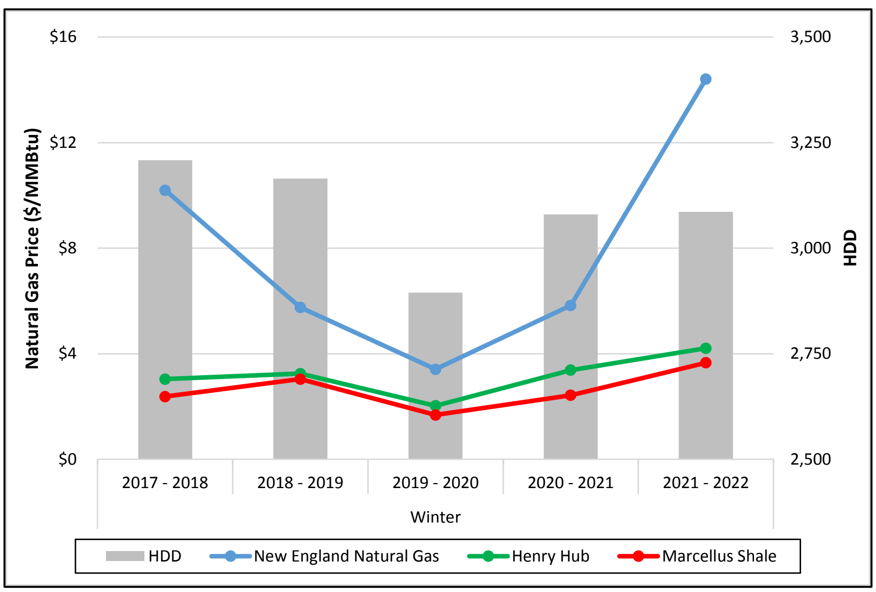
[17] The $62/MMBtu natural gas price represents an average price for the electric day (HE 1 - HE24) and not the gas day.

- No. 2 Oil prices averaged $16.49/MMBtu, a 57% increase compared to Winter 2021.
- No. 6 Oil prices averaged $16.08/MMBtu, a 45% increase compared to Winter 2021.

Overall, fuel prices have risen steadily since Spring 2020, when prices fell due to decreased demand for all fuels. In Winter 2022, average natural gas prices increased by $8.59/MMBtu (or 147%) compared to the same season last year. This increase was due to (1) cold weather during January 2022 (2) decreased Liquefied Natural Gas (LNG) injections and (3) low storage levels and tighter conditions throughout the country. High natural gas prices often pushed natural gas-fired generators up the supply stack, particularly beyond the cost of oil generation as discussed in the prior subsection.

Natural Gas: Since New England has no native natural gas production, prices at natural gas supply basins influence New England's natural gas prices. Figure 2-9 below compares annual average prices in New England (blue) to Henry Hub (green) and Marcellus (red) over the past five winters. Prices in the Marcellus region often trade below the Henry Hub price due to the prevalence of cheaper shale gas. Due to geographical proximity, Marcellus prices are more closely linked to New England gas prices, particularly during times when New England pipelines are unconstrained. However, cold winter weather can lead to constrained pipelines and higher price spreads between New England and Marcellus. To illustrate instances where colder weather contributed to high natural gas prices in New England, heating degree-days (gray) are shown in the bar charts on the secondary axis.[18] A higher gray bar indicates a colder winter.

Figure 2-9: New England Winter Natural Gas Prices and Heating Degree Days vs. Natural Gas Hub Prices

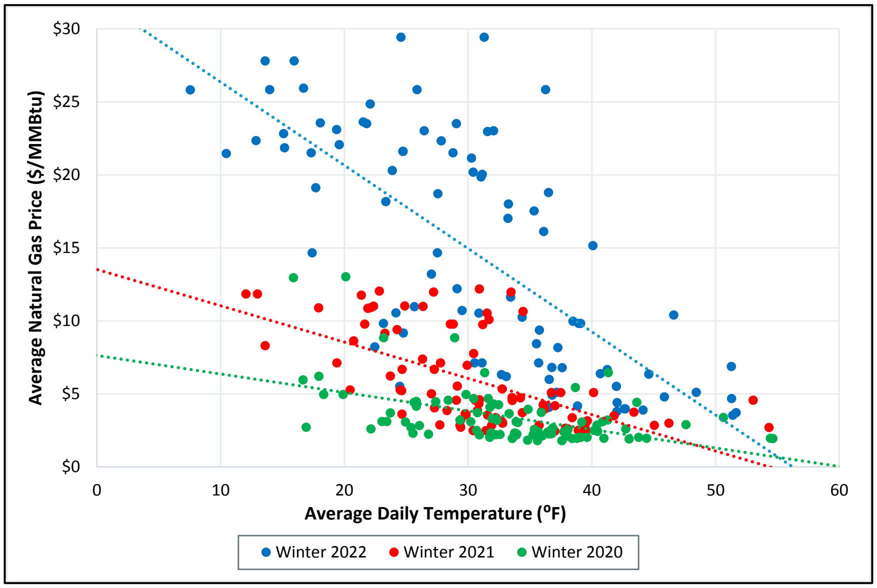


[18] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F,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

In Winter 2022, Henry Hub prices increased by 25% (or \$0.83/MMBtu) and Marcellus prices increased by 51% (or \$1.23/MMBtu) compared to Winter 2021. Natural gas prices increased across the country as natural gas demand growth outpaced supply growth during the year. The increased demand, including LNG export demand, led to lower levels of natural gas storage compared to historical averages heading into Winter 2022.[19] The higher supply basin prices, along with reduced LNG injections into New England, contributed to a tighter natural gas system and higher prices in New England.

When temperatures are low during the winter, gas-fired generators must compete for natural gas with heating demand for limited natural gas because of scarce gas network capacity. The resulting constraints on the natural gas system cause higher prices. The relationship between temperatures and gas prices is shown in Figure 2-10 below.

Figure 2-10: Average Daily Temperatures and Natural Gas Prices

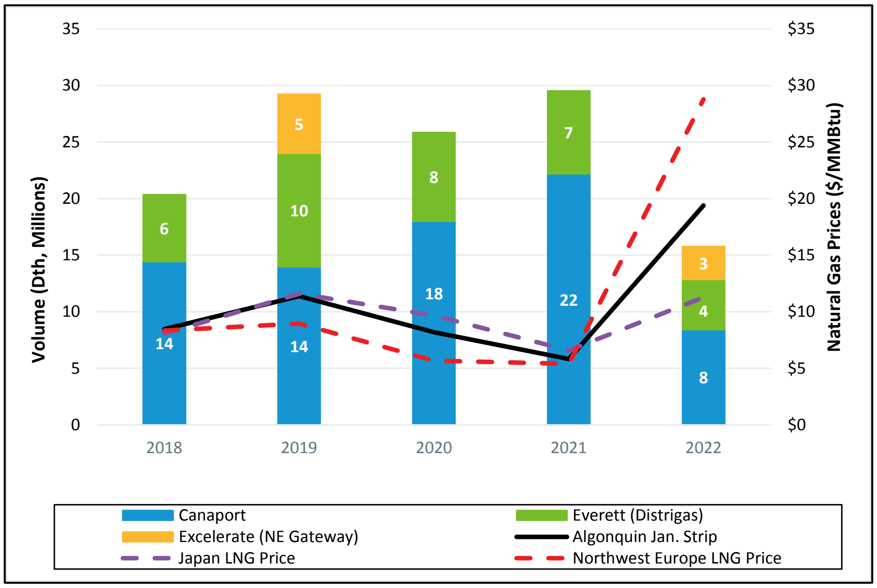


While lower temperatures often cause high natural gas prices, temperatures averaged 31°F during Winter 2022, which was unchanged from Winter 2021. Similarly, heating degree days (HDD) increased by only six HDDs year-over-year (3,086 HDDs vs. 3,080 HDDs). While quarterly average temperatures were unchanged compared to Winter 2021, sustained cold spells can lead to higher natural gas prices. During January 2022, sustained cold weather led to higher natural gas prices. From January 8 – January 31, temperatures averaged 22°F, which was 6°F colder than the same period in 2021. This period includes 11 days when temperatures averaged less than 20°F, which was the same amount as all of Winter 2020 and Winter 2021 combined. During this cold spell, natural gas prices averaged \$22.99/MMBtu compared to \$11.29/MMBtu throughout the rest of Winter 2022, and \$5.43/MMBtu over the same time period in January 2021. Another major impact on natural gas prices in 2022 was the decreased, higher priced LNG injections into New England.

[19] See the EIA Natural Gas Weekly Update for more information.

LNG: When natural gas pipelines become constrained in the winter, liquefied natural gas (LNG) can provide another source of natural gas delivery into New England pipelines. The additional natural gas can help alleviate constraints and subsequently reduce gas prices. There are three operational LNG import facilities that inject gas into New England: Excelerate, Canaport, and Everett (Distrigas).[20, 21] The volume of injections from each facility for the past five winters is illustrated in Figure 2-11 below. The lines (right axis) show the January 2022 forward natural contracts for Japan and Northwest Europe LNG (purple and red dashed) and Algonquin Citygates (black solid).[22]

Figure 2-11: LNG Sendout by Facility[23]



In Winter 2022, New England saw the lowest volume of LNG injections since Winter 2017, which contributed to higher natural gas prices. In Winter 2022, LNG injections into New England totaled 15.7 million Dth, a 47% decrease compared to Winter 2021 (29.5 million Dth). Of the three LNG import facilities, Canaport saw the largest decrease in LNG injections into New England, falling from 22.2 million Dth in Winter 2021 to 8.4 million Dth in Winter 2022. LNG injections into New England fell in Winter 2022 due to higher LNG prices in other global markets. For the winter, it may be economical to contract LNG deliveries forward and deliver them into New England when natural gas spot prices increase, especially during cold snaps. However, LNG prices in international markets increased in 2021, especially in European markets due to low storage levels at the end of their injection season.[24] While prices also

[20] The Canaport LNG facility is located in New Brunswick, Canada but delivers natural gas into New England via the Maritimes & Northeast pipeline.

[21] Additionally, the volume from the Everett (Distrigas) represents flows from the facility onto the interstate gas pipelines.

[22] The prices represent the average price for January 2022 contracts that traded in November. November trade dates were chosen due to data availability for European LNG forward prices. Earlier trade months likely better represent the timeline for scheduling LNG deliveries into New England. The IMM welcomes input from participants that would improve our understanding of LNG pricing and the timing of LNG deliveries.

[23] LNG delivery data is sourced from Genscape, while Algonqonquin forward contracts come from ICE for Winters 2021 and 2022 and S&P Global prior to 2020.

[24] For more information on European natural gas storage, see the EIA's Natural Gas Weekly Update.

increased in New England, the LNG prices in some international markets increased more substantially than New England prices, leading to decreased incentives to deliver LNG into New England.

Overall, the decrease in LNG in Winter 2022 resulted in 13.8 million Dth less of LNG supply, or enough natural gas to power a nearly 820 MW gas-fired generator for the entire winter.[25] Despite the decreased LNG injections into New England, LNG still plays a critical role in delivering natural gas supply for natural gas-fired generators. For example, on January 21, 2022, LNG injections into New England were high enough to supply all natural gas-fired generation on that day.

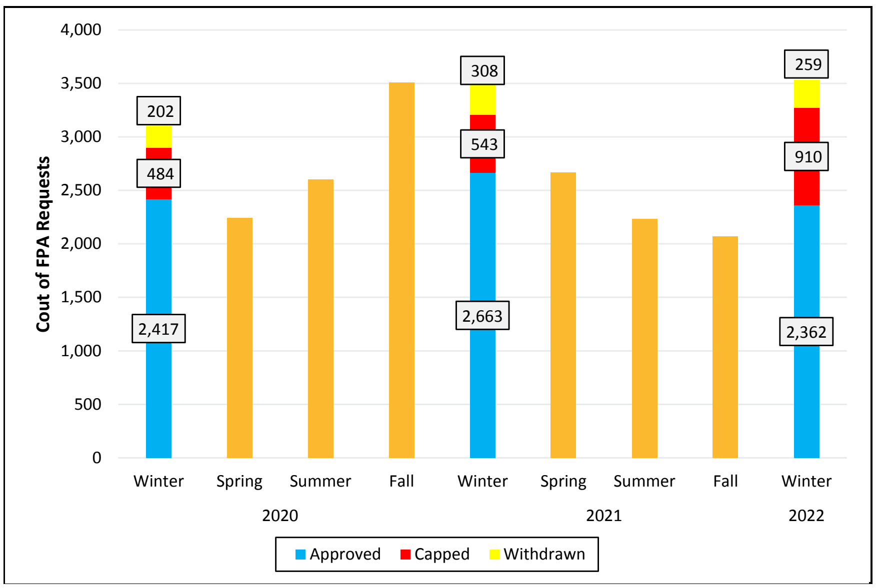
[25] Assuming a standard efficiency of 7,800 Btu/KWh.

2.4 Fuel Price Adjustments (FPAs) to Marginal Cost Reference Levels

In this subsection, we provide an overview and analysis of Fuel Price Adjustment (FPA) requests for Winter 2022. FPAs provide a means for participants to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index. As part of the FPA request assessment, the IMM uses a proprietary model to estimate a reasonable upper bound for natural gas prices ("FPA Limit").[26] For more details on how FPAs are processed, see Appendix: Overview of FPA Process, at the end of this report.

In Winter 2022, the IMM received FPA requests from 24 participants for over 60 generators, which is in line with Winters 2020 and 2021. Figure 2-12 presents the number of FPA requests by season over the last few years.

Figure 2-12: FPA Requests, by Year, Season, and Status



As indicated, the number of FPA requests spike in winter periods, averaging 830 more requests than other seasons.[27] While the number of FPA requests in Winter 2022 remained similar to last winter at around 3,500, the percent of capped FPAs increased from 16% in prior years to 26% in Winter 2022. This increase indicates both greater price volatility, price uncertainty, and additional factors discussed in reference to Figure 2-13 below. Consistent with prior years, the majority of FPAs (~86%) are made for the day-ahead market.[28]

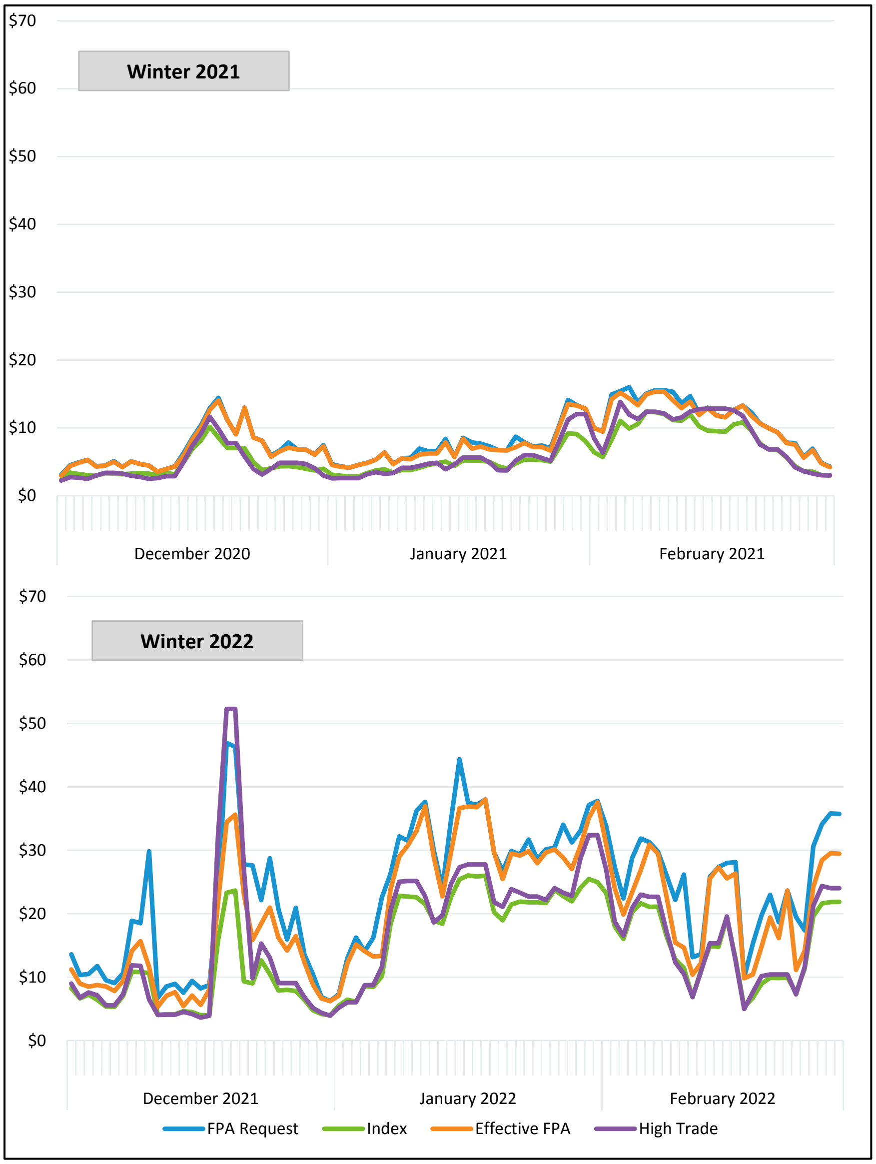
[26] Once processed, FPAs fall into one of three groups: approved, capped, or withdrawn. "Approved" indicates that the requested price was approved (either automatically or through IMM intervention) and used to update reference levels; "capped" indicates that the requested FPA price exceeded the FPA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

[27] The data in this section are for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland and Tennessee gas pipeline Z6-200L, Tennessee gas pipeline Z6-200L North, and Tennessee gas pipeline Z6-200L South.

[28] Note that unless and FPA with withdrawn or overridden by another FPA, it will roll-over into the real-time market.

The following figure shows the average settled index price for natural gas, average volume-weighted high-priced trade, requested FPA prices, and effective FPA price on a daily basis for the last two winter periods.[29] Because there are no volumes associated with FPA requests, the IMM calculates the prices as the simple averages of the variables associated with the FPA request in effect for a given hour. Subsequently, the hourly values roll into daily averages.

Figure 2-13: Average Index Price, High Trade, FPA Request, and Effective FPA



In Winter 2022, the average FPA request was approximately 66% higher than the settled fuel index price for the corresponding market day and 46% higher than the average high trade. While high, there are several unquantifiable factors which likely reduce concern. First, there is a natural upward bias as marginal assets may not expect to pay the settled index price (calculated as the volume-weighted average), nor even necessarily the highest transacted price, but

[29] The effective FPA price refers to the lesser of the FPA request and the cap (i.e., the fuel cost in effect for that market hour).

sometimes the highest offered price (or even higher depending on their size and run profile). While the bid-ask information is available during the FPA consultation window, ex-ante these data are not available to the IMM.

Additionally, certain hubs in New England face liquidity issues. For example, because the Algonquin Citygates trading hub trades infrequently (only once in Winter 2022), the IMM currently uses the more liquid Algonquin Citygates (non-G) index price as a proxy when setting reference levels.[30] Participants submitted 220 FPA requests for Algonquin Citygates over the course of the winter, all of which likely overstated the differences mentioned above. Additionally, pipeline operators issued numerous operational flow orders (OFOs) over the course of the winter, constraining the ability to transact in natural gas (these data are not collected by the IMM). In such situations, IMM on-call analysts frequently received correspondence from participants indicating that if they ran their expectation was that they would need to purchase LNG, which reflected high global prices (discussed above).

While 26% of submitted FPAs were capped in the Winter 2022 period, the cumulative effect of the capping was relatively small as effective FPAs corresponded to approximately 87% of the requested values. Finally, as no participant violated the Tariff relating to FPA requests, no generator was locked out from using the FPA mechanism during Winter 2022.

2.5 Energy Market Opportunity Cost Adjustments to Marginal Cost Reference Levels

Beginning December 1, 2018, energy market reference levels have included an energy market opportunity cost (EMOC) adder for resources that maintain an oil inventory.[31] The update was motivated by concerns that, during sustained cold weather events, generators were unable to incorporate opportunity costs associated with the depletion of their limited fuel stock into their energy supply offers due to the risk of market power mitigation. Such an event arose during Winter 2018 - which resulted in ISO operators posturing oil-fired generators to conserve oil inventories. During cold weather events, the inclusion of opportunity costs in energy offers enables the market to preserve limited fuel for hours when it is most needed to alleviate tight system conditions.

We calculate generator-specific EMOC adders with a mixed-integer programming model that was developed by the ISO and runs automatically each morning. For a given forecast of LMPs and fuel prices, the model seeks to maximize an oil-fired generator's set revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and asset operational characteristics. Opportunity costs produced by the model are available to participants an hour before the day-ahead market closes and, since December 2019, a real-time opportunity cost update is available at 6:30 pm, on the day prior to real-time operation. The real-time update of the opportunity cost calculation is based on data that is available after the day-ahead market closes but prior to the start of the real-time market. This calculation incorporates updated fuel price forecasts to produce more accurate opportunity costs for the real-time market.

While the calculation of EMOCs is complicated and dependent on a number of variables (gas and oil price forecasts, fuel inventory levels, and generator characteristics), it is possible to

[30] The Non-G hub excludes transactions requiring delivery of natural gas on the "G" lateral of the Algonquin pipeline and so, likely, always trades at a discount to Algonquin Citygates which does not enforce such a constraint.

[31] https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_energy_market_opp_costs_for_oil_and_dual_fuel_revised_edition.pdf

develop a general sense about when EMOCs are likely to occur. Primarily, we should expect to see EMOCs for a generator when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to physically exhaust their oil-fired inventory. This type of scenario would typically occur during an extended period of very cold weather when demand for natural gas is highest because natural gas is used for both heating and electricity generation in New England. Table 2-2 below displays EMOC summary statistics for December 2021 to February 2022.

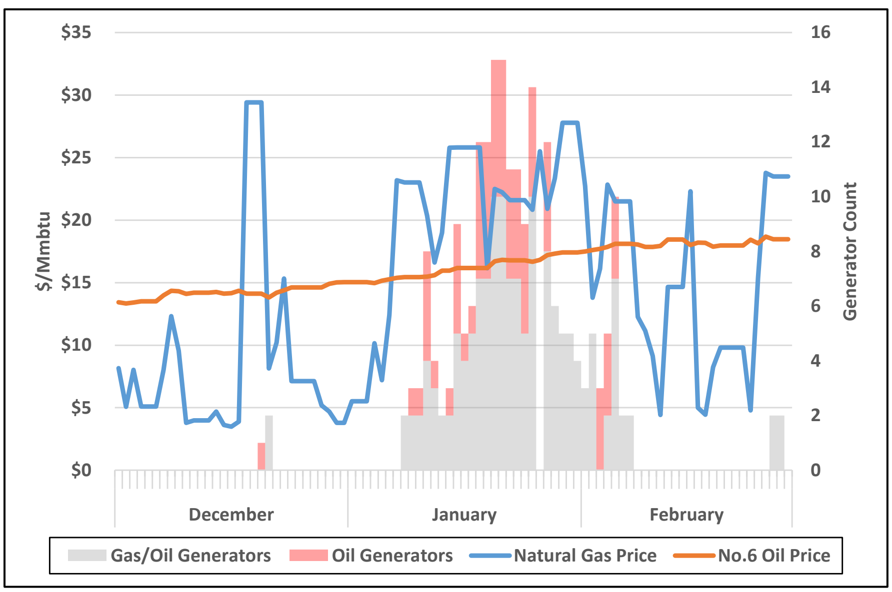
Table 2-2: EMOC Summary Statistics (Dec 2021 - Feb 2022)

Market Type	Generator Count	Avg. EMOC ($/MWh)	Avg. NG Price ($/MMBtu)	Avg. Oil Price ($/MMBtu)
Day-ahead	18	$19.14	$22.07	$16.73
Real-time	18	$18.11	$22.63	$16.85

From December 1, 2021, to February 28, 2022, eighteen generators received EMOC adders for their oil inventories in both the day-ahead and real-time market. Thirteen of the generators are dual-fuel capable while the remaining five generate on oil only. The EMOC adders were split across 34 days and 18 different generators in the day-ahead market, averaging around $19/MWh. In the real-time market, EMOC adders either continue from their DA value or can be revised using updated fuel prices. Across 28 days where DA EMOC adders were active, eight different assets received updated RT EMOC adders which averaged around $18/MWh.

The distribution of resources receiving EMOC adders in the day-ahead market from December 2021 to February 2022 is displayed in Figure 2-14 below. The natural gas and No.6 oil prices (left axis) are imposed over the count of generators receiving non-zero EMOC adders (right axis). Gas/oil-fired (dual-fuel) generators are shown with gray shading; oil-only generators are shown with red shading.

Figure 2-14: Day-Ahead Non-Zero EMOC Generator Count and New England Fuel Prices[32]



[32] A data error accounts for the missing asset count on January 26, 2022.

Due to New England's dependence on natural gas generation, increases in natural gas prices typically increase energy market prices, making oil-fired generation economical and incentivizing dual-fuel generators to switch to the lower-priced fuel, oil. During these periods of high gas prices, oil inventories can deplete, increasing the likelihood that an EMOC adder will be applied to reference levels. From December 2021 to February 2022, prolonged periods of higher natural gas prices were highly correlated with occurrences of EMOC adders. The second half of January 2022 saw the largest count of non-zero EMOC adders, with 15 generators affected on January 20 and 21.

We analyzed whether participants incorporated EMOC price adders in their offer prices during Winter 2022 by comparing MW-weighted offer prices to reference levels for all hours of December 2021 to February 2022. We expected this ratio to remain relatively consistent if participants were including the EMOC adder in their offers. However, oil-only generators did not appear to incorporate the adder into their offers, while results for dual-fuel generators showed no evidence that the adder was incorporated for those units either.

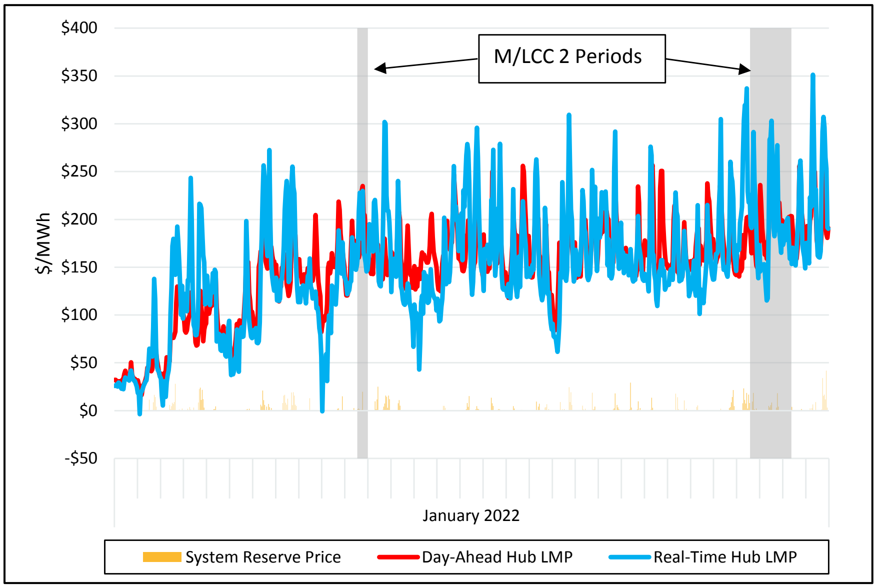
In addition to our internal analysis, we surveyed a selection of participants directly on EMOC adder usage. The participants' responses confirmed that the EMOC adder did not play a significant role in the development of their offers as they remained confident in their fuel reserves and delivery arrangements during all prolonged periods of high energy prices. The calculation of the EMOC adder does not consider restocking during the seven-day optimization horizon and, consequently, may overstate the opportunity cost of burning oil. Therefore, we would only expect participants to take advantage of the EMOC adder when fuel delivery is less certain during extreme winter conditions.

2.6 System Operations

System Events

Two Master Local Control Center Procedure No. 2 (M/LCC 2)[33] events occurred during Winter 2022. Figure 2-15 shows average hourly hub LMPs and reserve prices during January 2022, when both of the M/LCC2 events occurred.

Figure 2-15: January 2022 Hourly Hub LMPs and System Reserve Prices

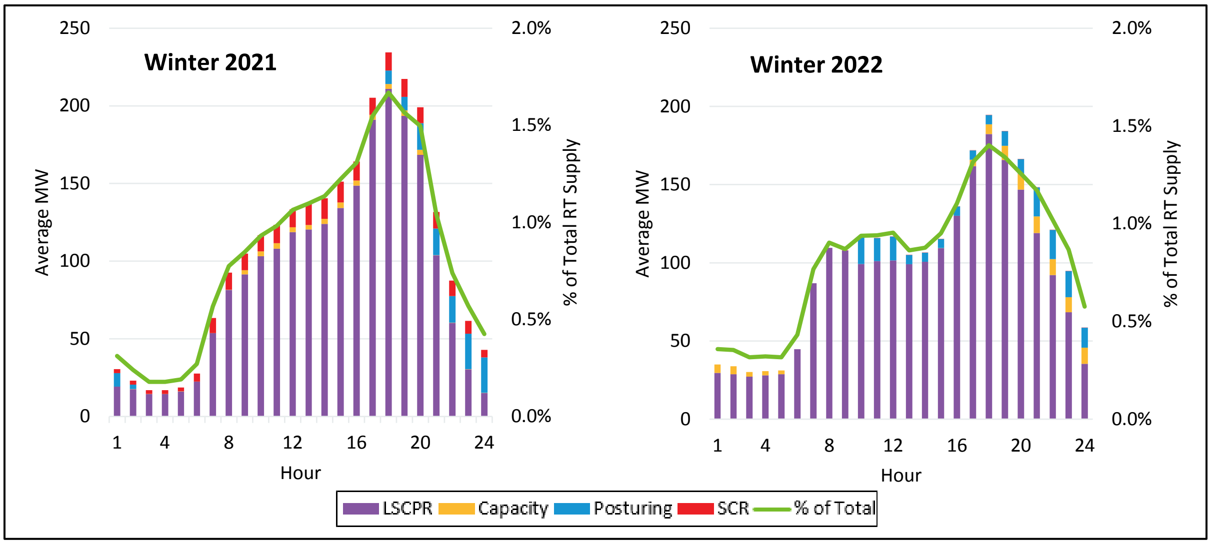


January 11: The first occurred on January 11 due to an imminent capacity deficiency. The M/LCC 2 event lasted from 14:00 until 24:00. Heading into the day, the operators expected a surplus of 1,278 MW during the peak hour (hour ending 19:00). At 11:00, ISO-NE operators were informed that imports from New York would likely be reduced due to constraints on NYISO's system. Approximately 90 minutes later, one of the poles on Phase II tripped, which led to a 650 MW loss of imports from Canada. Additionally, between 8:30 and 14:30, four oil generators that cleared 1,000 MW of oil generation in the day-ahead market tripped offline. This led to a roughly 1,000 MW total deviation in real-time supply from those four generators between 14:00 and 17:00. Around 14:00, operators manually committed additional gas and oil generators to maintain operating reserves over the steep evening ramp. The generators produced up to 960 MW during the M/LCC2 event. By 17:00, the Phase II pole was restored, and New York restored the import capability into ISO-NE. Hourly real-time prices peaked in hour ending 20:00 at $233/MWh, which was similar to the peak day-ahead price ($205/MWh). Despite transmission trips and generation trips, the supply margin remained high and there was minimal reserve pricing.

33 M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability.

The operators made several commitments for capacity toward the end of the M/LCC2 event on January 11. During system events, the operators may make supplemental commitments to maintain system reliability. Figure 2-16 below shows supplemental commitments by hour for each quarter by different commitment types. The orange bars in the evening and overnight hours of Winter 2022 (right graph) represent capacity commitments made on January 11, which were a majority of the capacity commitments during the quarter. Operators only postured pumped-storage units during the Winter (blue bars), and local second contingency protection commitments were similar between the two Winters (purple bars).

Figure 2-16: Reliability Commitments and Posturing During Winter



January 29: The second M/LCC 2 event occurred on January 29 due to severe weather, when Winter Storm Kenan brought heavy wind gusts and high snowfall totals across New England. Southeast New England was most heavily impacted, with wind gusts above 80 miles per hour, and snowfall totals around 30 inches. The M/LCC 2 event was in effect from January 28 at 15:00 until January 30 at 9:00. To prepare for the storm, the ISO increased staffing to support the control room, and held additional calls with local control centers and pipeline operators. There were minimal transmission and generator outages during the storm. At the peak, roughly 125,000 customers lost power during the storm. Hourly day-ahead prices peaked at $260/MWh on January 29 in hour ending 18:00, and hourly real-time prices peaked at $303/MWh on January 29 in hour ending 13:00.

Section 3
Review of the Sixteenth Forward Capacity Auction

This section presents a review of the sixteenth Forward Capacity Auction (FCA 16), which was held in February 2021 and covers the capacity commitment period (CCP) beginning June 1, 2025 through May 31, 2026. The section includes an assessment of market competiveness (including IMM mitigation), key auction inputs, and overall outcomes.

We will begin with a summary of FCA 16 outcomes. At the beginning of the auction, qualified capacity (37,630 MW) exceeded the Net Installed Capacity Requirement (NICR of 31,645 MW) by 5,985 MW.[34] The surplus decreased from FCA 15 (7,269 MW) as a result of a sharp decline in qualified capacity of 2,909 MW year-over-year, comprised of 900 MW less existing capacity and 2,000 MW less new capacity. System-wide capacity cleared 1,165 MW above NICR, only a 186 MW decrease in surplus from FCA 15. Varying cleared capacity amounts above and below limits in import- and export-constrained zones led to three levels of price separation in the fourth and final round of the auction :

- Rest-of-Pool at $2.59/kW-month.
- Southeastern New England at $2.61/kW-month (import-constrained).
- Northern New England at $2.53/kW-month (export-constrained).

Payments for FCA 16 are expected to be $1.0 billion, a decrease of 21% from FCA 15, driven by lower clearing prices in the Rest-of-Pool and Southeastern New England capacity zones and lower cleared capacity (or capacity supply obligations, CSOs) system wide.

From FCA 15 to FCA 16, Net ICR decreased by 1,625 MW. The 5% decrease in Net ICR is mostly driven by a significant change in reconstituting passive demand response (DR) resources in the ISO load forecast.[35] In FCA 16, the reconstitution method was recalculated to more accurately reflect passive DR resources' CSO contribution; the change directly resulted in a 1,545 MW decrease in the Net ICR.[36] A total capacity of 1,540 MW dynamically de-listed[37] in FCA 16; including 780 MW of oil-fired generation, and 417 MW of gas-fired generation. New cleared capacity totaled 576 MW, primarily consisting of solar projects (209 MW), passive demand response (129 MW), and battery storage projects (102 MW). The substitution auction following

[34] All qualified and cleared capacity analysis excludes Killingly Energy Center. In November 2021, ISO-NE filed to terminate the 632 MW CSO of Killingly Energy Center, which was accepted and upheld by the Commission. Per the filing, the project sponsor had not made sufficient progress to achieve Killingly Energy Center's critical path schedule milestones. With the insufficient progress, the commercial operation date for Killingly Energy Center was more than two years beyond June 1, 2022, which is the start of the Capacity Commitment Period in which the resource first obtained a CSO.

[35] To prevent energy efficiency resources from double-benefiting from both reducing base load and receiving capacity supply obligation (CSO) payments, the ISO reconstitutes, or adds back in, the estimated amount of passive DR CSO into each yearly load forecast. The reconstituted amount of load will offset the load reduction from passive DR resources, preventing the double-benefit.

[36] The ISO filing to FERC on the passive DR reconstitution changes can be found here: https://www.iso-ne.com/static-assets/documents/2020/09/ee_reconstitution_tariff_changes.pdf

[37] A dynamic de-list bid is a one year de-list bid submitted at a price below the Dynamic De-list Bid Threshold (DDBT), which was $2.61/kW-month in FCA 16. Dynamic de-list bids are not subject to mitigation from the IMM.

FCA 16 did take place, however no demand bids or supply offers cleared due to offer price divergence between existing resources and new sponsored policy resources.

3.1 Review of FCA 16 Competitiveness

The IMM reviews competitiveness both before and after the primary auction occurs. Prior to the auction, bids and offers can be mitigated to IMM-determined values if they incorrectly represent a resource's costs. After the auction, participant behavior is reviewed alongside the presence of market power; we then assess whether the market power potentially impacted auction outcomes. Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 16.

3.1.1 Buyer-Side Market Power

A market participant attempting to exercise buyer-side market power will try to offer capacity below cost in an effort to *decrease* the clearing price. The mitigation rules are known as a Minimum Offer Price Rules (MOPR). A depressed clearing price benefits capacity buyers over capacity suppliers. To guard against price suppression, we evaluate financial information from new capacity resources for out-of-market revenues or other payments that would allow the market participant to offer capacity below cost.[38] We either replace the out-of-market revenues with market-based revenues or remove them entirely, and recalculate the offer to a higher, competitive price (i.e., the offer is mitigated).

In FCA 16, we reviewed 62 resources from 22 participants, accounting for 2,897 MW of capacity.[39] The difference between the MW-weighted average submitted price ($0.29/kW-month) and the price that went into the auction ($7.22/kW-month) for mitigated resources highlights the degree to which the buyer-side market power mitigation measures protect price formation from the price-suppressing effects of below cost offers under the MOPR construct.

3.1.2 Seller-Side Market Power

A market participant attempting to exercise seller-side market power will try to economically withhold capacity during the FCA – for a single year or permanently - in an effort to *increase* the clearing price above a competitive level. An inflated clearing price can benefit the remaining resources in the market participant's portfolio, as well as the portfolios of other suppliers. A market participant would only attempt this if they believed (1) their actions would inflate the clearing price, and (2) the revenue gain from their remaining portfolio would more than offset the revenue loss from the withheld capacity.

For market power mitigation purposes, we evaluate new import resources without transmission investments for seller-side market power.[40] In FCA 16, we reviewed 503 MW of general static de-list bids from six resources. We denied the price of two of the bids accounting for 438 MW, or 87%, of general static de-list bids. The magnitude of general static de-list price differences reflected a change of average price from $7.58/kW-month to $6.66/kW-month.

[38] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

[39] These values represent new supply generation and demand response resources that received a qualification determination notification. New supply imports are included in the seller-side market power section below.

[40] New imports resources with associated transmission investment are evaluated for buyer-side market power.

When a static de-list bid price is mitigated to a lower price, it limits the ability of suppliers to exercise market power should they be determined to be pivotal (described below).

3.1.3 Residual Supply Index

The Residual Supply Index (RSI) measures the capacity remaining in the market after removing the largest supplier. The continuous measure is on a scale from zero to infinity; an RSI greater than 100% demonstrates the market's ability to satisfy demand without the largest supplier. An RSI less than 100% indicates that the largest supplier is required to meet demand, potentially allowing seller-side market power.

In FCA 16, the RSI was measured for the entire system and Southeastern New England (SENE) capacity zone using the Net ICR and Local Sourcing Requirement (LSR), respectively, as the demand benchmarks. For the entire system, the RSI was measured at 101%, up slightly from 98% in FCA 15; a significantly lower Net ICR bolstered the pre-auction supply margin. For the SENE capacity zone, the FCA 16 RSI increased to 86% from the FCA 15 low of 79%. RSI increases at the system and zonal levels indicates fewer opportunities for pivotal suppliers and seller-side market power.

3.1.4 Pivotal Supplier Test

We use a Pivotal Supplier Test (PST) to determine which, if any, capacity suppliers may have the ability to exercise seller-side market power.[41] A supplier is deemed pivotal if, after removing the entirety of their capacity, the respective zone is unable to meet its corresponding capacity requirement.[42] If a supplier is pivotal, their associated static de-list bids and/or new supply offers (for the previously specified import types) will enter the auction with a mitigated price.[43]

For FCA 16, we conducted the PST at the system level and for the Southeastern New England (SENE) capacity zone. In order to be pivotal system-wide, a supplier needed an effective capacity portfolio of approximately 2,453 MW; no suppliers met this criterion at the system level. At the zonal level, Southeastern New England entered the auction with a supply margin of 87 MW. Twenty-five suppliers in SENE were pivotal in the auction; none of them submitted a static de-list bid, leading to no mitigation. None of the pivotal suppliers in SENE submitted a static de-list bid, and therefore no mitigation applied.

3.1.5 Intra-Round Activity

The pivotal supplier test above is limited to pre-auction calculations; once the auction begins, excess system-wide supply starts to decrease and additional suppliers can become pivotal. The fourth round of the auction was conducted below the dynamic de-list bid threshold (DDBT).

[41] As defined in Section III.A.23.4 of the Tariff, for the purposes of this test, "the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)." Note that because this PST does not include proposed new capacity, the resulting pivotal determinations are likely conservative.

[42] The IMM conducts the PST at both the system and the import-constrained zonal levels; consequently, the relevant capacity requirements are the Installed Capacity Requirement net of HQICCS (Net ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

[43] Barring the exceptions outlined in Section III.A.23.2.

Under the Tariff, the IMM does not review bids from existing resources below the DDBT, as it represents a proxy price of the likely net going forward costs of the marginal resource.

Southeast New England entered the fourth round with an excess of 856 MWs. Of the suppliers with portfolios larger than the supply margin, none submitted dynamic de-list bids.

The rest of the system entered the fourth round with approximately 3,115 MW of excess capacity. No suppliers held portfolios larger than 3,115 MW, indicating no opportunities for suppliers to exercise seller-side market power.

3.2 Auction Inputs

FCA 16 was the third auction with a demand curve that relied solely on the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an incremental change in capacity affects system reliability at various capacity levels.[44, 45]

The MRI curve is scaled to show prices that load is willing to pay at various levels of capacity, which in turn provides various levels of system reliability.[46] Net Installed Capacity Requirement (Net ICR) and Net Cost of New Entry (Net CONE) are used as the scaling points for the MRI curve. The Net CONE was recalculated for FCA 16; the reference technology reflects a break-even capacity payment ($7.47/kW-month) needed to cover the costs of a combustion turbine, which was selected as the most economically efficient resource the ISO reviewed.[47] The Net ICR value for FCA 16 was 31,645 MW, or 1,625 MW lower than in FCA 15. The decrease was driven by changes in passive demand response reconstitution (mentioned in the section summary) and adjustments in the modeling of battery storage and co-located resources.[48]

The Net ICR decrease resulted in a significant inward shift of the demand curve compared to prior auctions. The difference between demand curves and qualified capacity for FCAs 14, 15, and 16 are shown in Figure 3-1 below.

[44] For more information on why the ISO implemented a sloped demand curve, see Section 6.1 of the 2019 AMR.

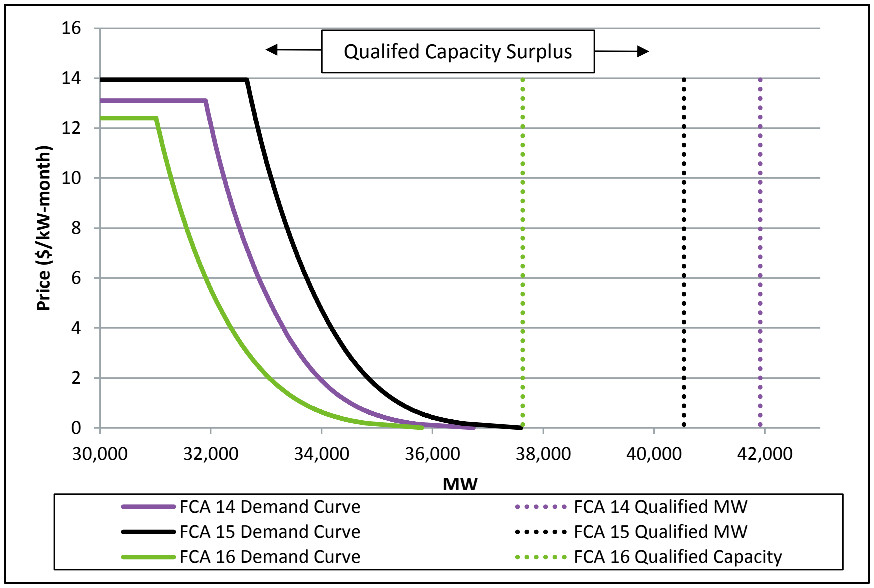
[45] Prior to FCA 14, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve. Pursuant to Section III.13.2.2.1 of the Tariff, the transition period began with FCA 11 and could last for up to three FCAs, unless certain conditions relating to Net ICR growth are met,.

[46] The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE".

[47] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). The study composed for the updated FCA 16 Net CONE calculation can be found here.

[48] For more information see https://www.iso-ne.com/static-assets/documents/2021/11/icr_for_fca_16.pdf

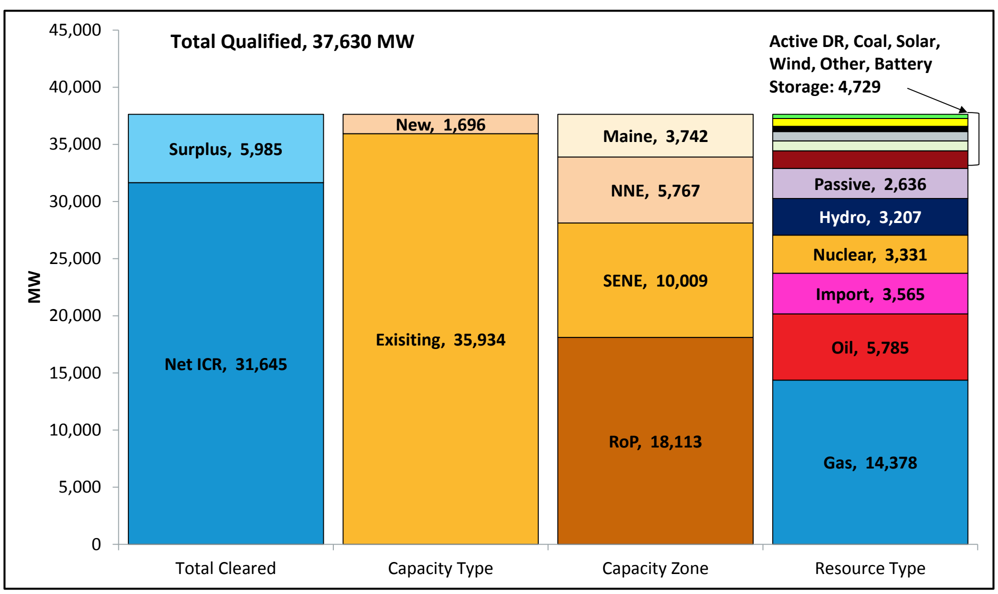
Figure 3-1: Net ICR and System Demand Curves



Compared to FCA 15, qualified capacity and system demand curve decreased considerably. The former decrease in qualified capacity was split between 925 MW less existing qualified capacity and 1,985 MW less new qualified capacity.[49] The qualified capacity surplus over Net ICR was 5,985 MW, down 18% from FCA 15 (7,269 MW).

Figure 3-2 below provides a breakdown of the 37,630 MW of qualified capacity in FCA 16. The three bars to the right show the breakdown of total qualified capacity across three dimensions: capacity type, capacity zone and resource type.

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



[49] Killingly Energy Center (632 MW) is excluded from existing qualified capacity amounts.

Overall, in FCA 16, qualified capacity exceeded Net ICR by 5,985 MW, or almost 19%. The first orange bar (by Capacity Type) shows that the qualified capacity from existing resources exceeded the Net ICR by 4,290 MW.[50]

The second orange bar (by Capacity Zone) shows the 10,009 MW of qualified capacity in SENE which exceeded the Local Sourcing Requirement (LSR) by roughly 560 MW. FCA 16 marked the second auction with the removal of 1,400 MW of existing capacity in SENE for Mystic 8 and 9, resulting in a lower capacity margin in the capacity zone.[51] The Northern New England (NNE) capacity zone had 8,568 MW of qualified capacity, only 10 MW more than the maximum capacity limit (MCL). Maine, modelled as an export-constrained zone nested within NNE, had 3,741 MW of qualified capacity, well below the MCL of 4,095 MW, meaning new capacity could be accommodated before constraining the export limit. The final bar breaks down qualified capacity by resource type. More information on total qualified and cleared capacity by resource type is provided in Section 3.4 below.

3.3 Auction Results

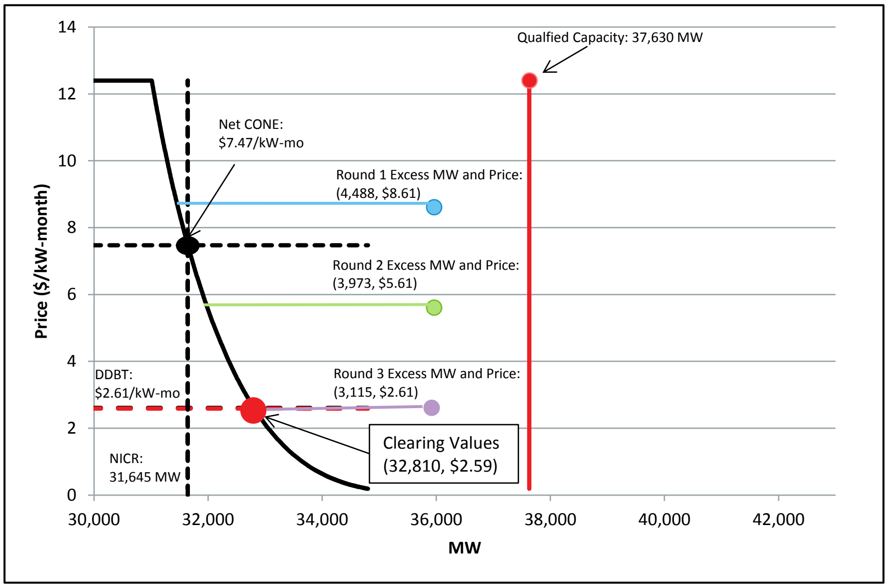
In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. These factors, which include the auction ISO-provided parameters as well as participant behavior, are summarized in Figure 3-3 below. On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black (values discussed in Section 3.2 above). On the *supply* side, the qualified and cleared capacities are shown as solid and dashed red lines, respectively. The clearing price of $2.59/kW-month can be seen at the intersection of the cleared MW (dotted red line) and the demand curve (solid black line) and right below the Dynamic De-list Bid Threshold (DDBT) price of $2.61/kW-month. Lastly, the blue, green, purple, and orange markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.[52]

[50] While certain imports are classified as new for other purposes in the FCA (see Section III.3.1.3 of the tariff), the IMM treats all qualified and cleared imports as existing for this report because there were no import resources in FCA 16 that increased New England's import capability. Treating imports elsewhere classified as "new" would conflate the actual amount of new capacity on the system.

[51] For more information on the end of the Mystic 8 and 9 cost-of-service agreement, see: https://www.iso-ne.com/static-assets/documents/2020/08/a7_fca_15_transmission_security_reliability_review_for_mystic_8_9.pdf

[52] The colored dots and lines move from cooler colors at high prices and capacity, to warmer colors at lower prices and less capacity.

Figure 3-3: System-wide FCA 16 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces. The fourth round opened with 3,115 MW of excess capacity at the system level (purple dot) and a price equal to the DDBT price, meaning existing resources could submit dynamic de-list bids to exit the market.[53]

In the fourth round, 1,975 MW of existing resources submitted de-list bids. In the Rest-of-Pool and SENE capacity zones, a fully rationable dynamic de-list bid placed at $2.59/kW-month resulted in system-wide capacity precisely matching system-wide demand. Prior to analyzing the rationable bid, the clearing engine analyzed whether to clear (remove CSO) or not clear (award CSO) two dynamic de-list bids right below the $2.59/kW-month clearing price. The bids had a Rationing Minimum Limit, indicating the clearing engine could only partially clear the bid to a minimum amount. These de-list bids placed below the clearing price would typically receive a CSO, however, the clearing engine found awarding the minimum allowable amount of CSO to either resource would decrease social surplus. Therefore, the two de-list bids did not receive a CSO even though they were priced below the Rest-of-Pool clearing price.

Price separation occurred in the SENE capacity zone as zonal supply was less than zonal demand at the Rest-of-Pool clearing price of $2.59/kW-month. The clearing engine moved up the supply curve to see if the removal of the next available supply offer triggered the supply shortfall. The removal of this bid at $2.90/kW-month did not result in zonal supply falling short of zonal demand, so the clearing engine descended until zonal demand intersected zonal supply, which occurred at $2.64/kW-month.

Zonal demand exceeded zonal supply in the NNE capacity zone at the Rest-of-Pool clearing price of $2.59/kW-month. Descending down from $2.59/kW-month, the clearing engine found that fully clearing a fully-rationable dynamic de-list bid placed at $2.53/kW-month would have

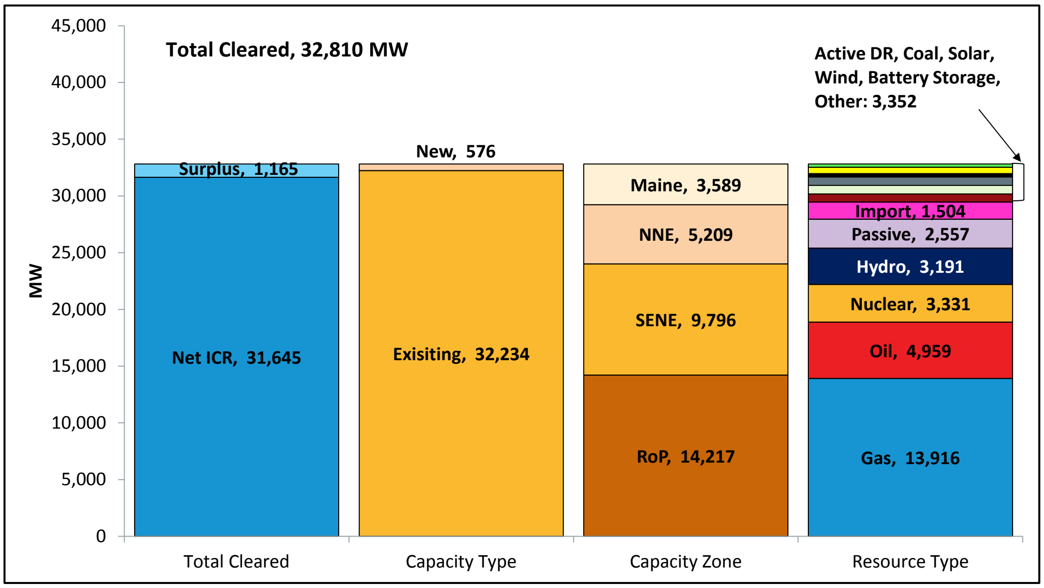
[53] Excess system capacity only includes import capacity up to the capacity transfer limit. Given the surplus capacity conditions associated with prices below the dynamic de-list bid threshold, it is difficult for a participant to profitably exercise market power. Therefore, dynamic de-list bids are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

resulted in zonal supply falling below zonal demand. The bid was then rationed to the MW amount that intersected zonal demand to zonal supply and the NNE clearing price was set at $2.53/kW-month.

3.4 Cleared Capacity

The amount of cleared capacity across several dimensions including capacity type, capacity zone, and resource type is shown in Figure 3-4 below. The height of each grouping equals total cleared capacity. As indicated in the first column, the amount of cleared capacity in FCA 16 exceeded system-wide requirements.

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

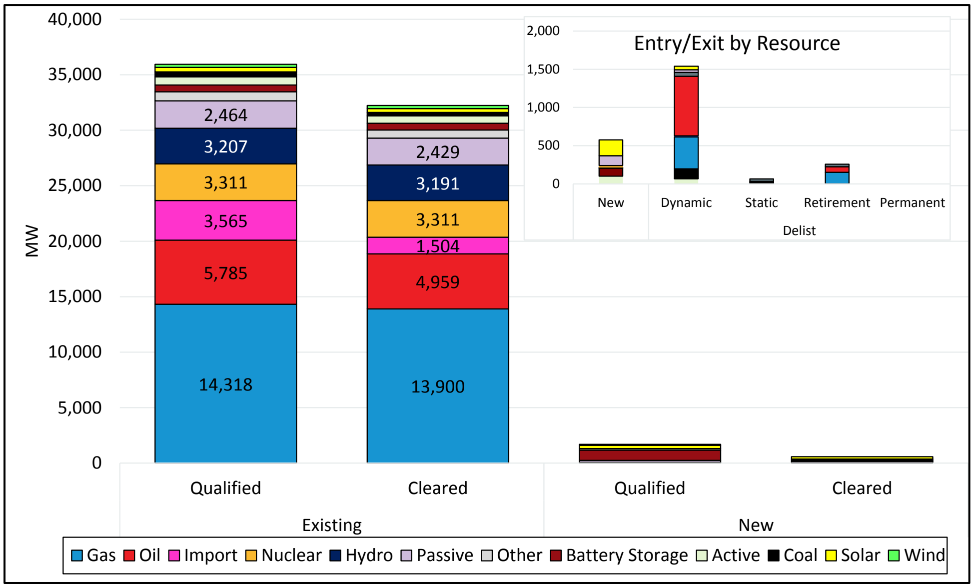


As excess supply declined during the auction, total surplus fell from 5,985 MW of qualified capacity to 1,165 MW of cleared capacity. The 4,820 MW difference stems from existing resources de-listing, and new supply resources exiting the market at prices greater than the $2.59/kW-month clearing price. The first orange bar (capacity type) illustrates that existing capacity accounted for 98% of cleared capacity.

The second set of orange bars (by Capacity Zone) shows sufficient capacity cleared in SENE compared to the LSR (9,796 MW versus 9,450 MW), reinforcing the minimal price separation that occurred in the zone. NNE cleared 8,568 MW and Maine cleared 3,741 MW of capacity, both below their respective MCLs. NNE capacity was still close enough to their MCL to warrant a slight decrease in clearing price. The final bar (by Resource Type) illustrates that gas-fired resources made up the largest portion of total cleared capacity at 42%. No resource types saw significant changes in cleared capacity in FCA 16.

Qualified and cleared capacity by new and existing resource types are broken down in Figure 3-5 below. There can be up to four different bars for each resource type (qualified-existing, cleared-existing, qualified-new, and cleared-new). Additionally, the inset graph displays new entry and de-list bids (static, dynamic, permanent, and retirement) by resource type.

Figure 3-5: Qualified and Cleared Capacity by Resource Type



Imports, gas-fired, and coal-fired resources made up the largest percentage reductions in existing capacity. Only 42% (1,503 MW) of qualified imports (3,564 MW) cleared the auction.[54] Coal-fired generation cleared only 68% (457 MW to 310 MW) of qualified capacity due to static and dynamic de-list bids from three resources. The dynamic de-list bid threshold was $2.61/kW-month, a few cents above the final auction clearing price. Below the threshold, any existing resource can submit a one-year dynamic de-list bid without mitigation review. A total of 1,540 MW dynamically de-listed, with 780 MW (51%) coming from oil-fired resources and 417 MW (27%) coming from gas-fired resources.

New cleared capacity in FCA 16 accounted for 576 MW of cleared capacity, a 56% decrease from new cleared capacity in FCA 15 (1,314 MW). With much less qualified capacity and lower clearing prices, new capacity projects had fewer opportunities to remain in the auction. The largest portion of new capacity came from solar projects (208 MW) and passive demand response (128 MW). New battery storage projects cleared only 102 MW in FCA 16, down from 596 MW in FCA 15.

3.5 Comparison to Other FCAs

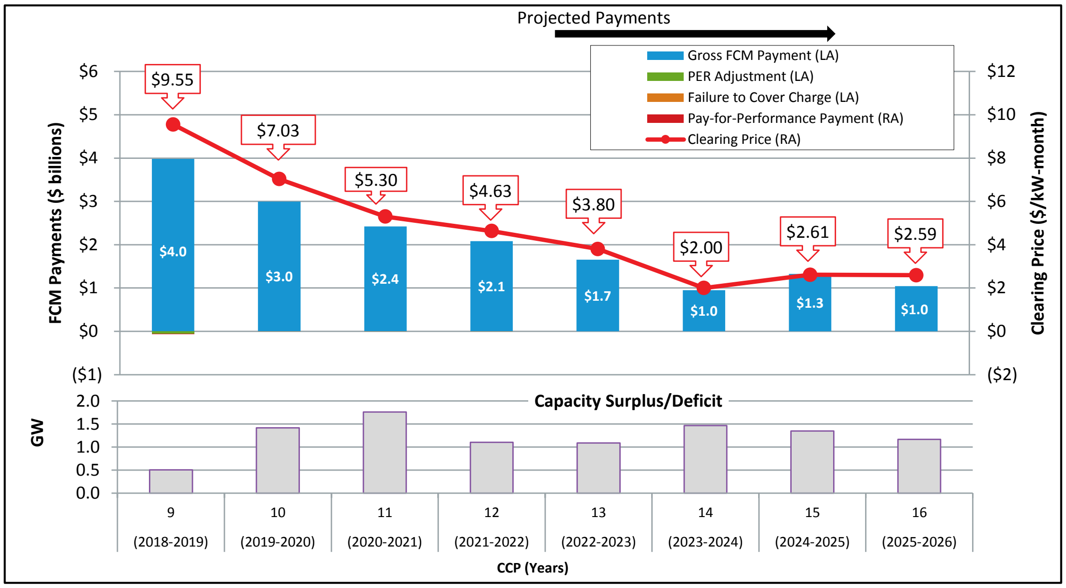
Underlying FCA clearing prices and volumes drive trends in FCM payments. Payments for CCPs 9 through 16 are shown in Figure 3-6 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 12 through 16 are projected payments based on FCA outcomes, as those periods have not yet been settled.[55] The green bar represents Peak Energy Rent (PER) adjustments and the red bar represents Pay-for-Performance (PFP) payments made in past commitment periods. The red line series represents the existing resource clearing price in the

[54] While all other types of existing resources enter the FCA as fixed capacity, import resources must qualify and receive a new CSO every FCA.

[55] Payments for incomplete periods, CCP 12 through CCP 16, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

Rest-of-Pool capacity zone.[56] Payments correspond to the left axis while prices correspond to the right axis. Lastly, the purple bars below the payments represent a capacity surplus (positive) or deficiency (negative) compared to Net ICR.

Figure 3-6: FCM Payments by Commitment Period



The graph shows that as capacity surplus has increased year-to-year, clearing prices and estimated payments have declined significantly from the FCA 9 peak. Projected payments for FCA 16 are $1.0 billion, down from $1.4 billion in the prior auction. Despite only a small dip in clearing prices compared to FCA 15, projected payments decreased substantially in FCA 16 due to a decline in total capacity obligations (CSOs) and a lower price (or less price separation) in the import-constrained Southeastern New England (SENE) capacity zone.

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

Section 4
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2020 through Winter 2022. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 4-1 below.

Table 4-1: High-level Market Statistics

Market Statistics	Winter 2022	Fall 2021	Winter 2022 vs Fall 2021 (% Change)	Winter 2021	Winter 2022 vs Winter 2021 (% Change)
Real-Time Load (GWh)	31,230	27,682	13%	30,922	1%
Peak Real-Time Load (MW)	19,738	20,035	-1%	18,924	4%
Average Day-Ahead Hub LMP ($/MWh)	$110.34	$54.18	104%	$51.30	115%
Average Real-Time Hub LMP ($/MWh)	$105.48	$53.87	96%	$51.66	104%
Average Natural Gas Price ($/MMBtu)	$14.41	$5.07	185%	$5.83	147%
Average No. 6 Oil Price ($/MMBtu)	$16.08	$14.81	9%	$11.09	45%

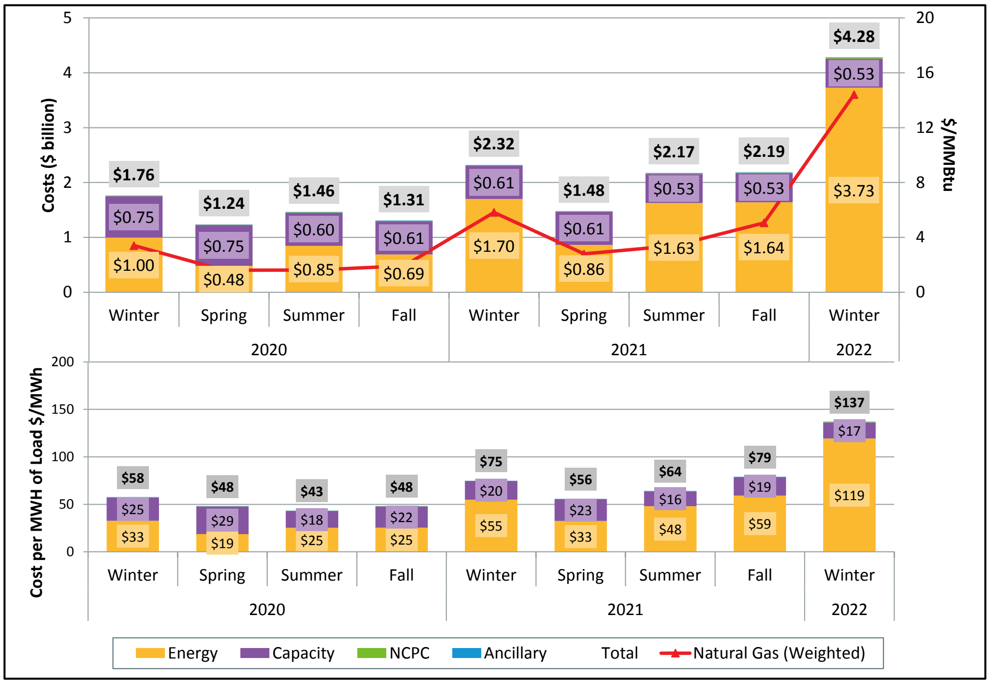
To summarize the table above:

- Higher average natural gas prices ($14.41/MMBtu vs $5.83/MMBtu) drove the increase in energy costs in Winter 2022 compared to Winter 2021. Gas prices increased 147% year-over-year. Section 2 above discusses higher gas prices in more detail. Average daily gas prices exceeded $20/MMBtu on 32 days in Winter 2022, compared to zero days in Winter 2021. The maximum gas price in Winter 2022 was $29.42/MMBtu, compared to $12.18/MMBtu in Winter 2021.
- High gas prices were the primary driver of a $110.34/MWh average day-ahead LMP, 115% higher than in Winter 2021 ($51.30/MWh). The increase in gas prices outpaced energy prices because generators were able to run on lower cost oil and coal during periods of high gas prices.

4.1 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 4-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [57,58]

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



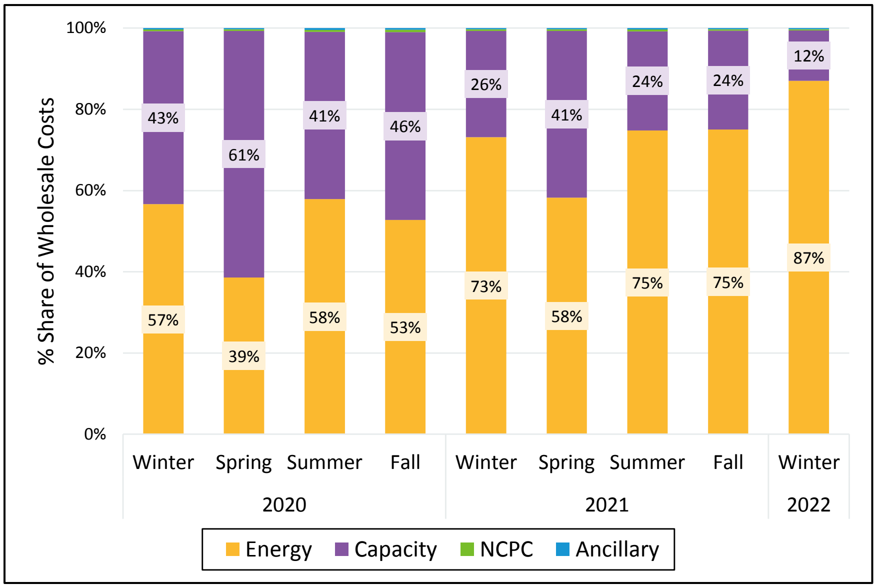
In Winter 2022, the total estimated wholesale cost of electricity was $4.28 billion (or $137/MWh), an increase of 85% compared to $2.32 billion in Winter 2021, and an increase of 96% over the previous quarter (Fall 2021). Natural gas prices continued to be a key driver of energy prices.

Energy costs were $3.73 billion ($119/MWh) in Winter 2022, 119% higher than Winter 2021 costs, driven by a 147% increase in natural gas prices. Energy costs made up 87% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 4-2 below.

[57] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Starting this report (Winter 2022), we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all five-years of data. Transmission network costs, known as regional network load (RNL) costs, are also included in the estimate of annual wholesale costs.

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

Figure 4-2: Percentage Share of Wholesale Cost



Capacity costs are determined by clearing prices in the primary capacity auctions, and totaled $531 million ($17/MWh), representing 12% of total 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. Clearing prices were lower in FCA 12 due to a lower net installed capacity requirement and lower net cost of new entry, which in turn lowered the demand curve for FCA 12 compared to FCA 11.

At $13.8 million ($0.44/MWh), Winter 2022 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. Section 5.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $11.2 million ($0.36/MWh) in Winter 2022. Ancillary service costs increased by 85% compared to Winter 2021. Regulation capacity costs, part of ISO-NE's ancillary services, increased by $6.0 million compared to Winter 2021 due to higher energy costs.

4.2 Load

Cold weather in January 2022 led to slightly higher average load in Winter 2022 compared to Winter 2021.[59] Average hourly load by season is illustrated in Figure 4-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 4-3: Quarterly Average Load

In Winter 2022, hourly loads averaged 14,458 MW, a 1% increase compared to Winter 2021 and a 3% increase compared to Winter 2020. The higher loads were driven by colder weather during January 2022, when temperatures averaged 25°F, a 4°F decrease compared to January 2021 (29°F).

[59] In this section, "load" typically refers to *Net Energy for Load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand, and net interchange (imports minus exports). NEL excludes pumped-storage demand. "Demand" typically refers to metered load. (NEL – Losses = Metered Load).

Load and Temperature

The monthly breakdown of average load compared to total heating degree-days (HDD) over the last three winter seasons is shown in Figure 4-4 below.[60]

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

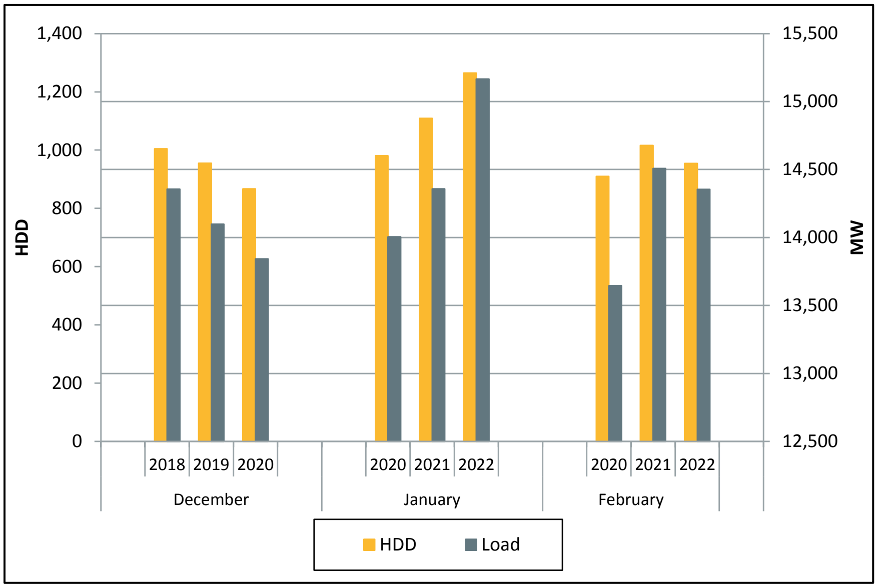


Figure 4-4 shows that January 2022 had the highest number of HDDs and also the highest average load over the reporting period. In January 2022, temperatures averaged 25°F, which led to 1,265 HDDs, a 156 increase compared to January 2021 (1,109 HDDs). This colder weather led to increased heating demand and therefore, higher average loads. During the month, loads averaged 15,166 MW, a 1% (or 808 MW) increase compared to January 2021 (14,358 MW).

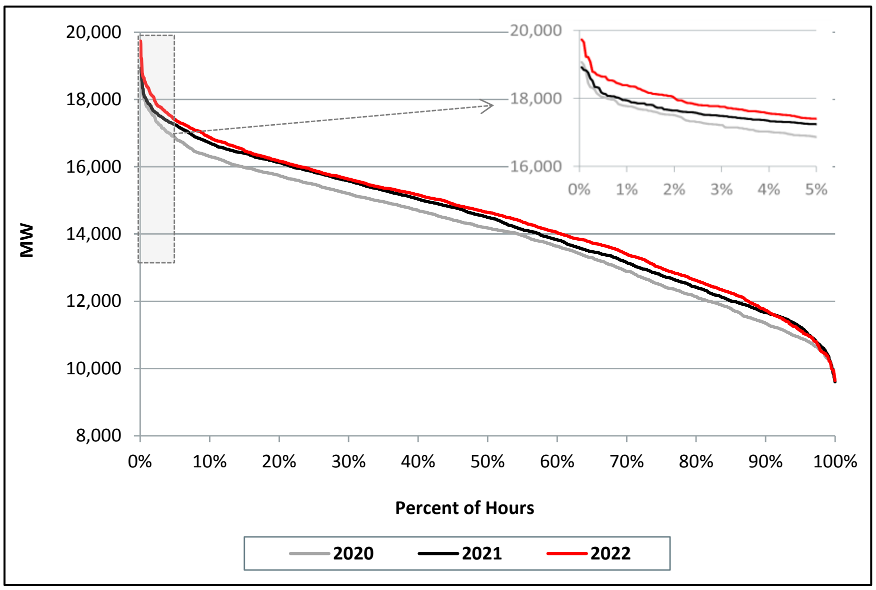
In both December 2021 and February 2022, average load fell year-over-year due to warmer temperatures, along with increased energy efficiency and behind-the-meter solar generation. In December 2021, temperatures averaged 37°F, a 2°F increase compared to December 2020 (40°F). The warmer temperatures contributed to a 256 MW decrease in average load (13,843 MW vs. 14,099 MW). In February 2022, average temperatures increased by 2°F (31°F vs. 29°F) year-over-year, contributing to the 153 MW decrease in average load (14,355 MW vs. 14,508 MW). The other major driver of decreased load was increased behind-the-meter solar generation. In February 2022, behind-the-meter solar generation averaged 191 MW per hour, an 80% increase from February 2021 (106 MW).

[60] 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.

Peak Load and Duration Curves

New England's system load over the past three winter seasons is shown as load duration curves in Figure 4-5 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 that load levels occur at that level or higher. Winter 2022 is shown in red, Winter 2021 is shown in black and Winter 2020 is shown in gray.

Figure 4-5: Seasonal Load Duration Curves



The red line shows Winter 2022 had slightly higher loads across nearly all hours compared to both Winter 2021 and Winter 2020. In Winter 2022, loads were higher than 16,000 MW in 23% of hours, compared to nearly 22% and 15% in Winter 2021 and Winter 2020, respectively. During peak hours (top 5%), Winter 2022 load levels were higher than both prior winters. In the top 5% of hours in Winter 2022 loads averaged 17,987 MW, 318 MW higher than in Winter 2021 (17,669 MW) and 558 MW higher than in Winter 2020 (17,429 MW). Winter 2022 saw higher loads during these hours as a result of cold weather during January 2022. Six of the coldest ten on-peak days over the entire reporting period occurred during January 2022, leading to higher peak loads.

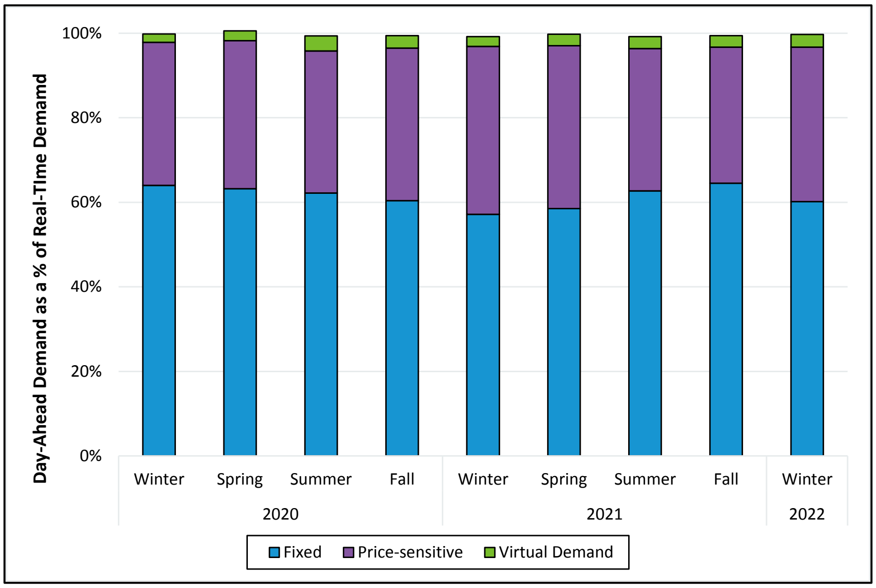
Load Clearing in the Day-Ahead Market

Over the past several years, higher percentages of real-time end use load have cleared 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.[61] For example, when low levels of demand clear in the day-

[61] 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 capacity to the market.

ahead market, supplemental generator commitments or additional dispatch may be needed 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 4-6 below. Day-ahead demand in broken down by bid type: fixed (blue) price-sensitive (purple) and virtual (green) demand.[62]

Figure 4-6: Day-Ahead Cleared Demand by Bid Type



In Winter 2022, participants cleared 99.7% of their real-time demand in the day-ahead market. This was higher than in Winter 2021 (99.2%) but slight lower than in Winter 2020 (99.8%). Higher cleared demand resulted from an increase in fixed demand, which accounted for 60.2% of day-ahead cleared demand in Winter 2022, compared to 57.2% in Winter 2021 but 64.0% in Winter 2020. Increased cleared virtual demand also contributed to higher day-ahead clearing. In Winter 2022, virtual demand accounted for 3.0% of all day-ahead cleared demand, up from 2.3% in Winter 2021 and 2.0% in Winter 2019. However, the increase in fixed demand and virtual demand was partially offset by a 3.4% increase in price-sensitive demand compared to Winter 2021 (36.6% vs. 39.7%). Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced well above the LMP. Such transactions are, in practical terms, fixed demand bids. Therefore, the shift from fixed demand bids to price-sensitive demand bids results in no significant market impacts.

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[62] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time demand is equal to native metered load. 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 end use load is calculated as generation – asset-related demand + price-responsive demand + net imports. The IMM has 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.

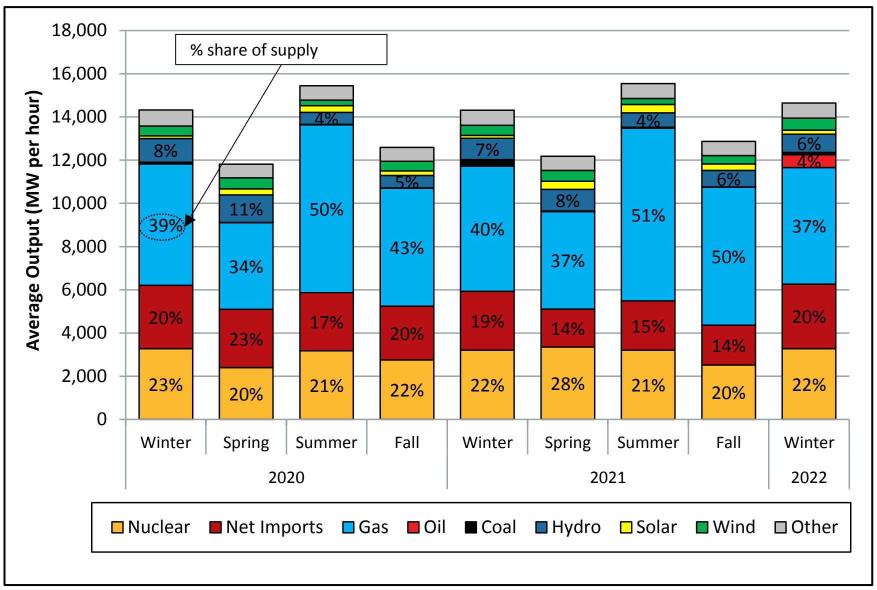
4.3 Supply

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

4.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2020 through Winter 2022 is illustrated in Figure 4-7 below.[63] The bar's height represents average electricity generation, while the percentages represent percent share of generation from each fuel type.[64]

Figure 4-7: Share of Electricity Generation by Fuel Type



Note: "Other" category includes battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

The majority of New England's generation comes from nuclear generation, gas-fired generation, and net imports (netted for exports). These three together accounted for 80% of total energy production in Winter 2022. Notably, oil generation accounted for 4% of total generation, or 584 MW per hour of generation on average. Due to higher gas prices, oil-only and dual-fuel generators ran economically on oil throughout the Winter. For reference, Winter 2020 and Winter 2021 had 29 MW and 69 MW per hour of oil generation, on average. Despite high gas prices, natural gas remained the largest share of generation. Generators operating on gas provided 37% of total generation, only 3% less than in Winter 2021. The decline was offset by the oil generation discussed above. Net imports, which make up roughly 20% of generation each winter, increased from Fall 2021 when transmission work across the New York North and

[63] "Other" category includes battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

[64] Electricity generation in Section 4.3.1 equals native generation plus net imports.

Phase II interfaces led to lower total transfer capability. This reduced the amount of imports that could safely flow into New England.

4.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York during Winter 2022.[65] On average, the net flow into New England was about 2,987 MW per hour. New England met about 21% of its Winter 2022 average load (NEL) with power imported from New York and Canada. This is slightly higher than the average of the prior eight seasons (18%). The average hourly import, export and net interchange power volumes by external interface for the last nine quarters are shown in Figure 4-8 below.

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

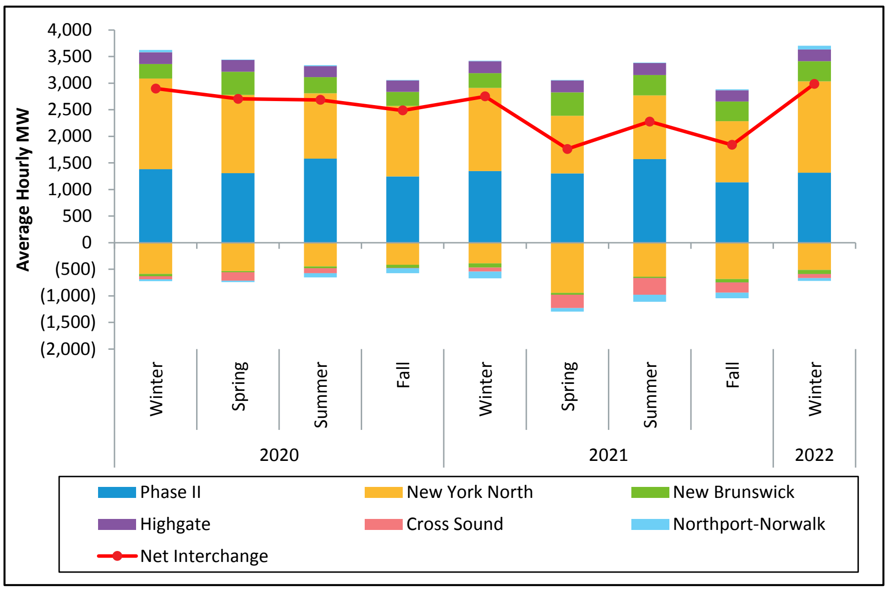


Figure 4-8 illustrates that net interchange and imports generally rise in the summer and winter quarters when New England energy prices and demand tend to be higher. The average hourly net interchange value of 2,987 MW was up 62% from Fall 2021 (1,838 MW) and 9% from Winter 2021 (2,751 MW).

The increase in net interchange between Winter 2021 and Winter 2022 was driven by increases in net interchange at the Northport-Norwalk and New Brunswick interfaces. Net interchange over the largest interface, Phase II, was consistent with Winter 2021 levels, decreasing by around 2% from the prior winter, or by just 32 MW, on average.

Scheduled export transactions at the Northport-Norwalk interface were lower in Winter 2022 than in Winter 2021 (51 MW per hour versus 127 MW per hour, on average, respectively). In addition, scheduled real-time import transactions increased from 9 MW per hour in Winter

[65] 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.

2021 to 70 MW per hour in Winter 2022. Overall, New England went from being a net exporter over this interface for the last seven seasons (since Winter 2020) to a net importer (20 MW per hour, on average) in Winter 2022. The main driver behind this flip was a change in the price spread at the interface. New England prices were $5/MWh *lower* than New York prices in Winter 2021 but $2/MWh *higher* than New York prices in Winter 2022.

Scheduled import transactions at the New Brunswick interface were higher in Winter 2022 than in Winter 2021 (277 MW per hour versus 379 MW per hour, on average, respectively). In Winter 2022, prices at the Salisbury node were much higher than in Winter 2021. Similar to the real-time Hub LMP, real-time prices at New Brunswick doubled, from an hourly average of $50/MWh in Winter 2021 to $101/MWh in Winter 2022. Scheduled exports in Winter were consistent with Winter 2021, averaging 78 MW per hour in both seasons.

The largest share of imports (1,717 MW per hour on average) into New England in Winter 2022 (46%) came from the New York North interface; this is consistent with Winter 2021 (1,565 MW per hour on average). Exports at the New York North interface increased by 31% between Winter 2021 (388 MW per hour) and Winter 2022 (507 MW per hour). Phase II contributed 36% of the total average hourly imports during Winter 2022. Imports at the Phase II interface decreased by 2% from Winter 2021 (1,346 MW per hour) to Winter 2022 (1,318 MW per hour).

Section 5
Day-Ahead and Real-Time Markets

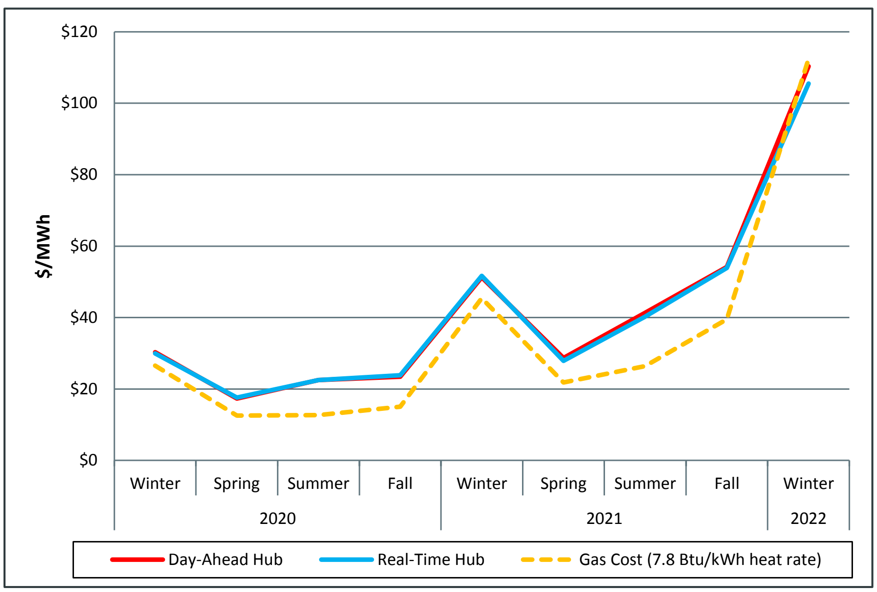
This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

5.1 Energy Prices

The average real-time Hub price for Winter 2022 was $105.48/MWh, 4% lower than the average day-ahead price of $110.34/MWh. These were the highest average winter Hub LMPs since Winter 2014, when day-ahead and real-time Hub prices averaged $138.71 and $137.59, respectively. Winter 2014 natural gas prices averaged $19.34/MMBtu, compared to $14.41/MMBtu in Winter 2022.

Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 5-1 below. The natural gas cost is based on the seasonal average natural gas price and a generator heat rate of 7,800 Btu/kWh.[66]

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



As Figure 5-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand.

Gas costs averaged $112.41/MWh in Winter 2022. Average electricity prices were about $2/MWh lower than average estimated Winter 2022 gas costs in the day-ahead market, unlike in the previous two winters when LMPs were higher than gas costs. In Winters 2021 and 2020,

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

average day-ahead electricity prices were $6/MWh and $4/MWh higher than average estimated gas costs, respectively. The negative spread in Winter 2022 was due to an increase in oil generation compared to other winter quarters in the reporting period. Similarly, while average real-time and day-ahead prices increased substantially compared to Winter 2021 (up by 115% to 104% respectively), they did not increase as much natural gas prices, which increased by 147%. As a result of high natural gas prices, oil generators were in merit more often in Winter 2022 compared to other winter seasons. This put downward pressure on LMPs. See Section 5.2 for additional information on marginal resources and transactions.

Additionally, average real-time Hub prices in Winter 2022 were $4.86/MWh or 4% lower than average day-ahead prices. This spread resulted from several days throughout the quarter that saw significantly lower real-time LMPs due to factors including additional real-time renewable generation, less generation needed in real-time compared to the day-ahead cleared amount, and increased price sensitivity when midday loads were low.

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 5-2.

Figure 5-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

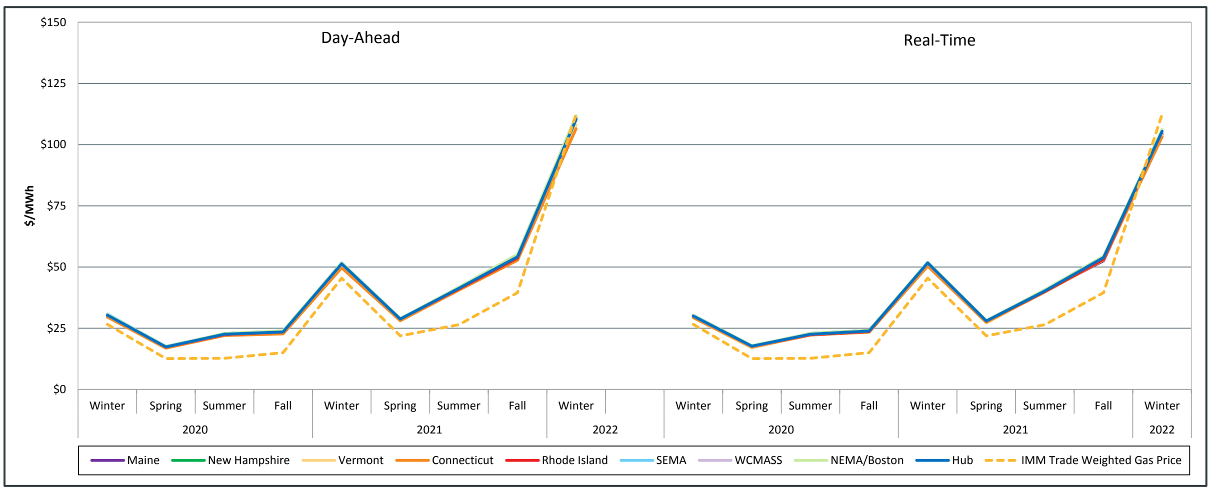


Figure 5-2 illustrates that load zone prices did not differ significantly from Hub prices in either market.[67] The Connecticut load zone saw the largest differences, with prices averaging slightly lower than the Hub price, a difference of 3% and 2% in the day-ahead and real-time markets, respectively. Connecticut has been export-constrained more frequently in recent years, due to the addition of new highly efficient and less expensive gas-fired generators in the load zone and limitations of the transmission system in exporting that power to the rest of the system.

[67] 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.

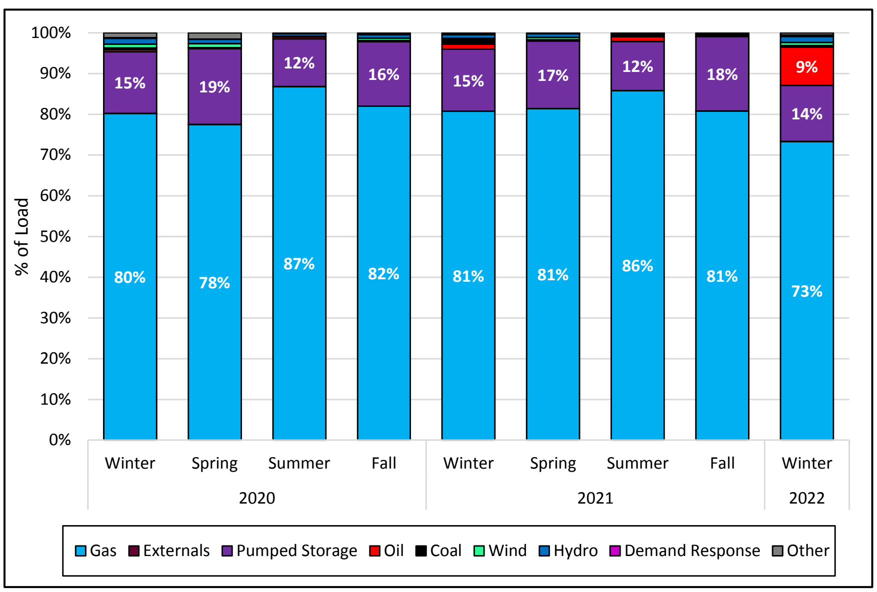
5.2 Marginal Resources and Transactions

The 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 termed "marginal". Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

In this section, marginal units by transaction and fuel type are reported 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 resources of different fuel types were marginal in the real-time market by season is shown in Figure 5-3 below.[68]

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



Oil displaced some natural gas-fired generation on the margin, setting price for 9% of load in Winter 2022. Due to higher gas prices this quarter, oil-fired generators and dual-fuel generators operating on oil were able to set price more frequently than in prior quarters. Natural gas-fired generators still set price for 73% of total load in Winter 2022. Coal-fired generators were

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

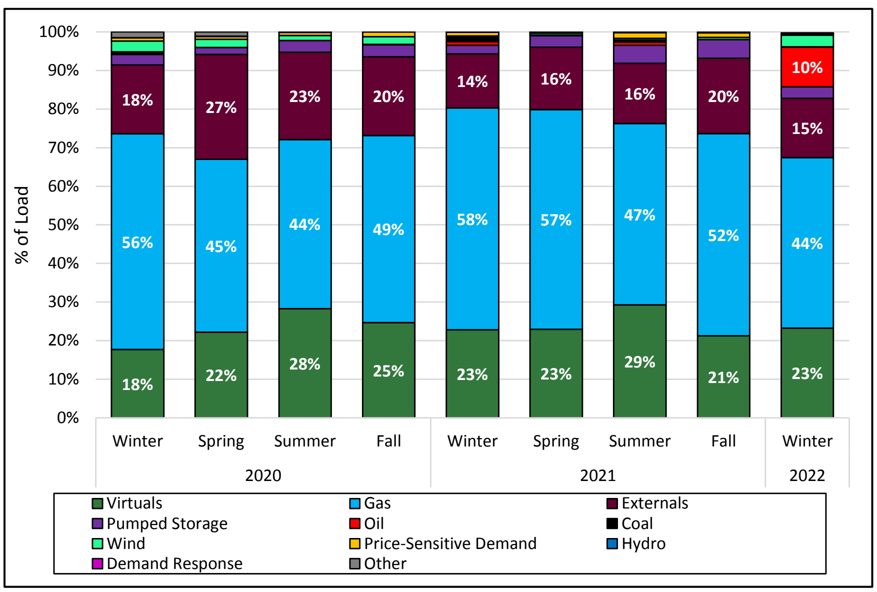
almost always inframarginal during the quarter, which is why they set price for less than 1% of load.

Pumped-storage units (generators and demand) set price for about 14% of total load in Winter 2022, which is similar to Winter 2021 (15%) and Fall 2021 (18%). 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 compared with fossil fuel-fired generators. Pumped-storage demand frequently sets price in off-peak hours, when energy prices are lower 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.

Wind was marginal for less than 1% of total load; most of which was located in *local export-constrained areas*, where the impact on the average load price was limited. Wind generators located in an export-constrained area can only deliver the next increment of load to a small number of locations within the export-constrained area. This is because the transmission network that moves energy out of the constrained area is at maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2020 is illustrated in Figure 5-4 below.

Figure 5-4: Day-Ahead Marginal Units by Transaction and Fuel Type

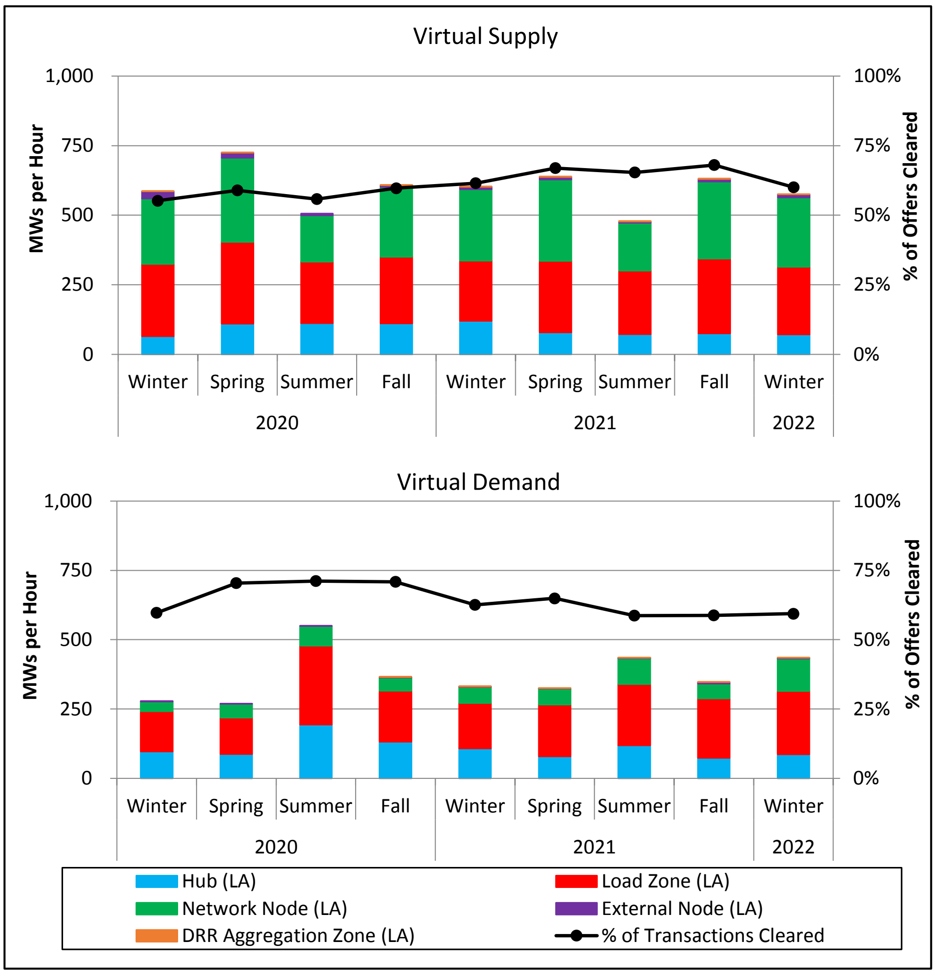


Natural gas-fired generators were the most frequent marginal resource type in the day-ahead market, setting price for 44% of total day-ahead load in Winter 2022. Like the real-time market, oil-fired and dual-fuel generators that were in merit displaced some natural gas-fired generation at the margin. Additionally, there was an increase in the amount of wind that set price. Wind generators may have high day-ahead offers if they account for the risk of wind availability, and thus real-time deviations and lost profit, in the real-time market. With higher energy market prices, wind generators offering at higher costs set the system price for 3% of load in Winter 2022.

5.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence. This indicates virtual transactions help the day-ahead dispatch model better reflect real-time conditions. The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 5-5 below. Cleared transactions are divided into groups based on the location 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 5-5: Cleared Virtual Transactions by Location Type



In Winter 2022, total *cleared* virtual transactions averaged approximately 1,011 MW per hour, which was an 8% increase compared Winter 2021 (936 MW per hour) and a 3% increase compared to Fall 2021 (979 MW per hour).

Cleared virtual supply totaled 575 MW per hour on average in Winter 2022, down 9% from Fall 2021 (631 MW per hour) and down 5% from Winter 2021 (603 MW per hour). In six of the last nine quarters, participants cleared more virtual supply at network nodes than any other location type. 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 make high-priced energy offers in the day-ahead market, but produce energy at low, or even negative prices in the real-time market. In Winter 2022, 43% (or 249 MW) of cleared virtual supply was located at network nodes compared to 42% (or 243 MW) at load zones and 12% (or 71 MW) at the Hub. External nodes and DRR aggregation zones combined to account for 2% (or 12 MW) of all cleared virtual supply in Winter 2022.

Cleared virtual demand amounted to 435 MW per hour on average in Winter 2022, up 25% from Fall 2021 (347 MW per hour) and up 31% from Winter 2021 (333 MW per hour). One participant significantly increased their cleared virtual demand in Winter 2022. This participant cleared an average of 65 MW per hour in Winter 2022, but cleared less than 1 MW per hour over the rest of the reporting period. Compared to cleared virtual supply, participants tend to clear a higher percentage of virtual demand bids at load zones since the same wind-related profit opportunities do not exist for virtual demand. In Winter 2022, participants cleared 52% (or 228 MW) of virtual demand bids at load zones, 27% (or 117 MW) at network nodes and 20% (or 87 MW) at the Hub. External nodes and DRR aggregation zones accounted for less than 1% of cleared virtual demand.

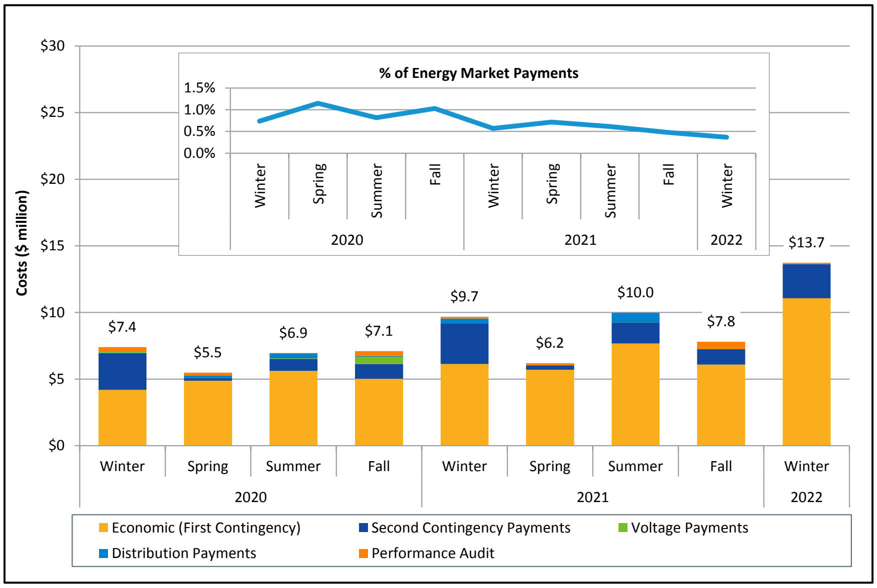
5.4 Net Commitment Period Compensation

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

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.[69] Payments by season and uplift category are illustrated below in Figure 5-6. The inset graph shows uplift payments as a percentage of total energy payments.

[69] 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).

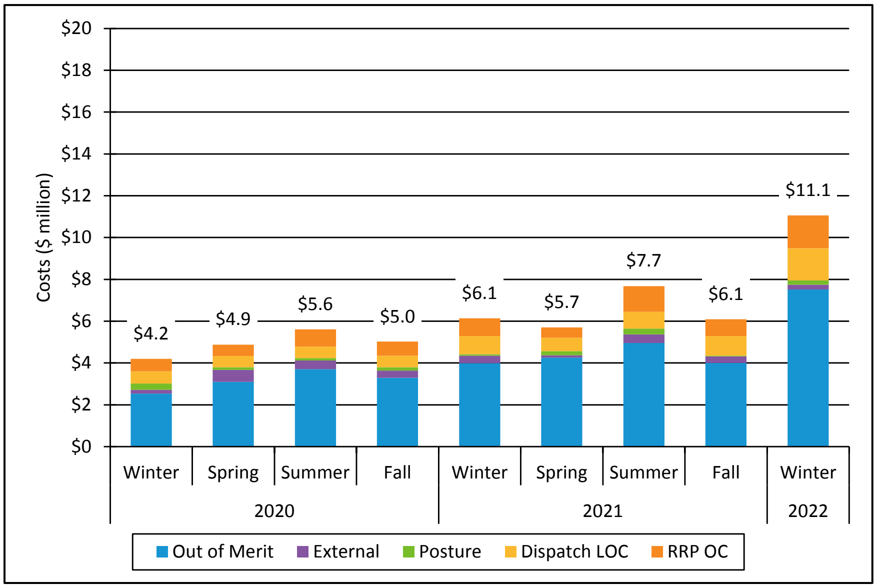
Figure 5-6: NCPC Payments by Category ($ millions)



NCPC payments in Winter 2022 totaled $13.7 million, which was higher than both prior winter periods. Total energy payments more than doubled (119%) from $1.7 billion in Winter 2021 to $3.7 billion Winter 2022, largely driven by a 147% increase in gas prices. Total NCPC payments also increased but not to the same extent. Total uplift payments rose by 42%, from $9.7 million in Winter 2021 to $13.7 million in Winter 2022. As a percentage of total energy payments, uplift fell to the lowest level in the reporting period, accounting for only 0.4% of total energy. The majority of uplift (81%) in Winter 2022 continued to be economic ($11.1 million), with most ($7.8 million) economic payments occurring in the real-time market. Economic NCPC rose by $4.9 million compared to Winter 2021.

Economic uplift includes payments made to resources providing first-contingency protection as well as 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 that resource. Figure 5-7 below shows economic payments by category.

Figure 5-7: Seasonal Economic Uplift by Sub-Category



As seen in Figure 5-7, out-of-merit payments generally comprise the majority of economic NCPC. These payments rose by 88% between Winter 2021 and Winter 2022, from $4.0 million to $7.5 million, making up 72% of the total $5 million increase. Posturing and external payments remained constant, within $0.15 million of Winter 2021 amounts.[70] Dispatch and rapid-response pricing opportunity cost payments, both real-time only types of uplift, made up the remainder of the increase. Dispatch lost opportunity cost payments[71] increased by $0.66 million, from $0.88 million in Winter 2021 to $1.53 million in Winter 2022. Similarly, rapid-response opportunity cost payments[72] increased by 87% from $0.84 million in Winter 2021 to $1.58 million in Winter 2022.

The next largest category of uplift during the reporting period was for local second-contingency protection (LSCPR), which accounted for 19% of all uplift payments. LSCPR payments totaled $2.6 million, down by $0.5 million from Winter 2021. Most LSCPR NCPC payments (90%) were made in December 2021. These payments went to generators that were committed in the day-ahead market to meet reliability needs in Maine, New Hampshire and SEMA/Rhode Island due to a planned transmission outages and limitations of the transmission system in flowing power across the system.

5.5 Real-Time Operating Reserves

Real-time reserve payments by product and by zone are illustrated in Figure 5-8 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

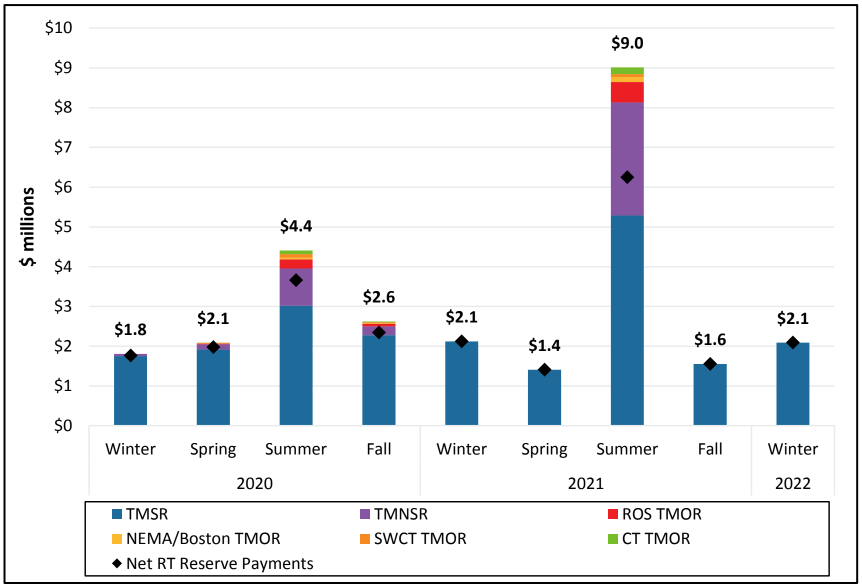
[70] Posturing payments are made to generators that follow ISO manual actions that alter their output from their economically-optimal dispatch levels in order to create additional reserves.

[71] Payments provided to a resource that is instructed by the ISO to run at levels below its economic dispatch point.

[72] 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.

same service. Net real-time reserve payments, which were $2.1 million in Winter 2022, are shown as black diamonds in Figure 5-8.

Figure 5-8: Real-Time Reserve Payments by Product and Zone



Winter 2022 reserve payments were nearly identical to Winter 2021 payments despite higher energy prices in Winter 2022 because the frequency of reserve pricing fell. Non-zero ten-minute spinning reserve (TMSR) prices were $16.24/MWh in Winter 2022, up from $9.75/MWh in Winter 2021. This was the result of higher energy dispatch costs. During the same period, non-zero TMSR pricing occurred in 224 hours in Winter 2022, down from 380 hours in Winter 2021. TMSR was the only reserve product with non-zero pricing, which is illustrated by only seeing the dark blue category in Figure 5-8. The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three winter seasons is provided in Table 5-1 below.[73]

Table 5-1: Frequency and Magnitude of Non-Zero Reserve Pricing

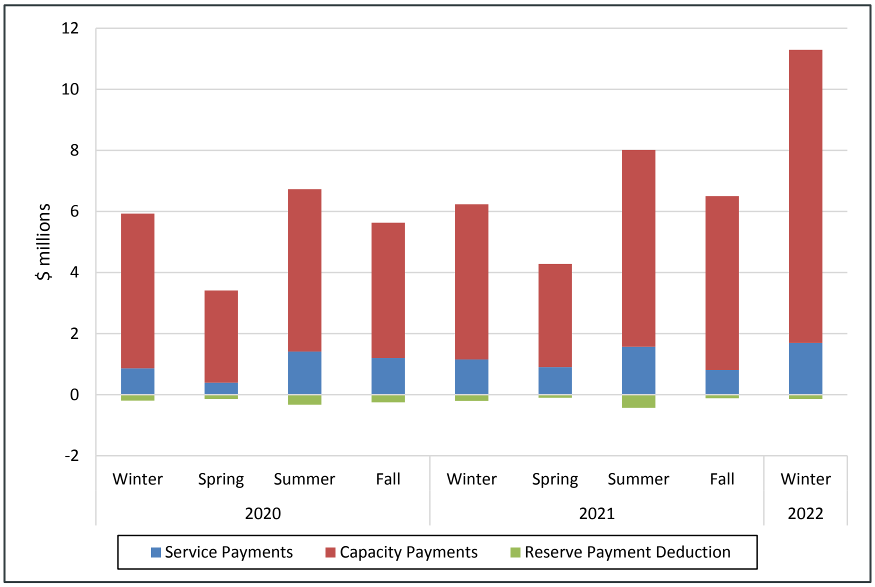
Product	Zone	Winter 2022		Winter 2021		Winter 2020	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$16.24	223.8	$9.75	379.9	$7.56	394.1
TMNSR	System	$0.00	.	$0.00	0.0	$74.24	0.6
TMOR	System	$0.00	.	$0.00	0.0	$0.00	.
	NEMA/Boston	$0.00	.	$0.00	0.0	$0.00	.
	CT	$0.00	.	$0.00	0.0	$0.00	.
	SWCT	$0.00	.	$0.00	0.0	$0.00	.

[73] Non-zero reserve pricing occurs when the pricing software must re-dispatch resources to satisfy the reserve requirement, which imposes additional costs to the system.

5.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 5-9 below.

Figure 5-9: Regulation Payments ($ millions)



Total regulation market payments were $11.2 million during the reporting period, up approximately 75% from $6.4 million in Fall 2021, and up by 85% from $6.0 million in Winter 2021. The increase in payments compared to the earlier periods resulted predominately from significantly higher regulation capacity prices in Winter 2022. Regulation capacity prices were affected by increased energy market opportunity costs in Winter 2022. Real-time energy market prices for Winter 2022 increased by 96% relative to Fall 2021 and 104% relative to Winter 2021.

Section 6
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. 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. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

6.1 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.[74] 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[75] to the sum of each participant's total supply that is available within 30 minutes.[76] 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 6-1 below.

[74] 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.

[75] 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*]

[76] 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 6-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2020	108.6	11%
Spring 2020	109.2	8%
Summer 2020	104.8	18%
Fall 2020	105.1	21%
Winter 2021	107.9	8%
Spring 2021	106.6	8%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	8%

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%. Winter 2022 saw one of the lowest frequencies of pivotal suppliers in the reporting period, at 8%. This value was similar to that of previous winters. 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. 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 nine quarters.

6.2 Energy Market Supply Offer Mitigation

We review 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.[77] Under certain conditions, we 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 the IMM may mitigate energy market supply offers.[78] These circumstances are summarized in Table 6-2 below.

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

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

Table 6-2: 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)	Pivotal Supplier	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)	Constrained Area	25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy	n/a	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.[79] The criteria are:

- *Structural test:* Certain 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).[80] 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).[81] This test only applies to general threshold energy and constrained area energy mitigation types.

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

[79] 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.

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

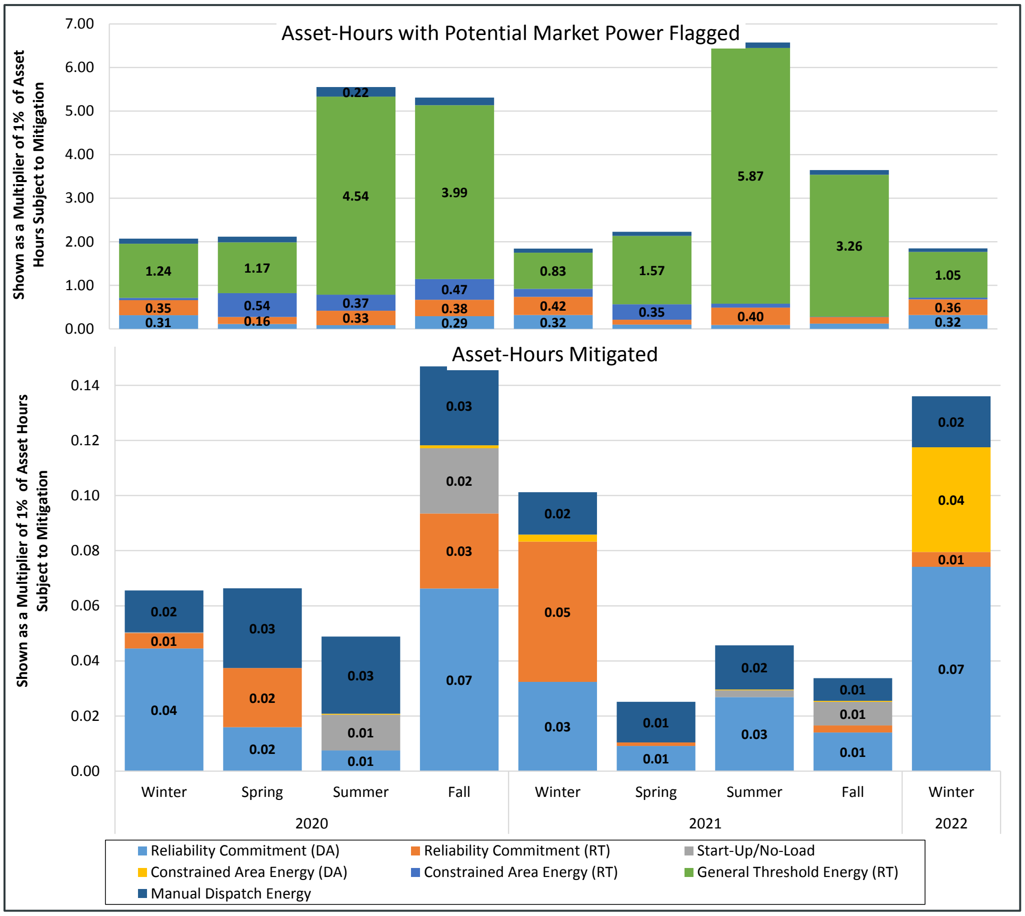
[81] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

(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 6-1 below.[82] 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.

[82] 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 6-1: Energy Market Mitigation[83]



In general, the data in Figure 6-1 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 shading) have had the lowest mitigation frequency at close to 0% over the review period; the increase in constrained area energy mitigation in Winter 2022 (in the day-ahead energy market) resulted from a frequently-binding transmission constraint (New England West-East constraint). (See section 7.2 for a description of this transmission constraint.) However, there were just 127 asset-hours of constrained area mitigation in that market. Both general threshold and constrained area mitigation have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

[83] 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.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[84] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, SEMA-RI and Maine had the highest frequency of reliability commitment asset-hours, 51% and 30% 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 SEMA-RI and Maine: 55% of mitigations occurred in SEMA-RI and 17% occurred in Maine in the day-ahead market.[85] Overall, reliability mitigations increased between Winter 2022 (248 asset-hours) and Winter 2021 (103 asset-hours). A small increase in reliability commitment asset hours (6%) in Winter 2022 compared to Winter 2021 does not explain the increase in reliability commitment mitigations; instead, the generators chosen for reliability commitments were more likely to offer supply at premiums greater than 10% above reference offer levels in Winter 2022 compared to Winter 2021.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[86] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. There were 59 asset hours of start-up and no-load mitigation in Winter 2022. 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; in Winter 2022, these same two participants accounted for 73% of start-up and no-load mitigation.

Constrained area energy (CAE) mitigation:[87] 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 141 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. Most of the failures

[84] 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.

[85] 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.

[86] 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.

[87] 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.

occurred in 2020 (66%); 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 Winter 2022, there were very few hours of structural test failures (141 asset-hours) in the real-time market, and there were no asset-hour of constrained area energy mitigation. In the day-ahead market for Winter 2022, there were 127 hours of mitigation, resulting from congestion along a frequently-binding constraint in December 2021 (the New England West-East Constraint).

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 66% of the structural test failures and four participants accounted for 78% of structural test failures over the review period. The frequency of pivotal supplier asset-hours increased in Winter 2022 (by 8%), compared to Winter 2021.[88]

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 27% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). Manual dispatch is relatively infrequent in the real-time energy market, with just a few hundred asset-hours occurring each quarter. Combined-cycle generators have the highest frequency of manual dispatch; this is consistent with manual dispatch frequently occurring in the context of (1) regulation service provided to the real-time energy market and (2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address short-term issues on the transmission grid. In Winter 2022, there were 267 asset-hours of manual dispatch and 62 asset-hours of mitigation. Fall 2021 experienced more asset-hours of manual dispatch (342) and fewer asset-hours of manual dispatch mitigation (26). Winter 2021 manual dispatch asset-hours were essentially the same (299 asset-hours) as asset-hours for Winter 2022, and mitigation asset-hours in Winter 2021 were lower (at 49 asset-hours).

[88] As noted in section 6.1 (Pivotal Supplier and Residual Supply Indices), the mitigation software's pivotal supplier test is different from pivotal supplier metric presented in section 6.1. 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 7
Forward Markets

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

7.1 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.[89] 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.[90] 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

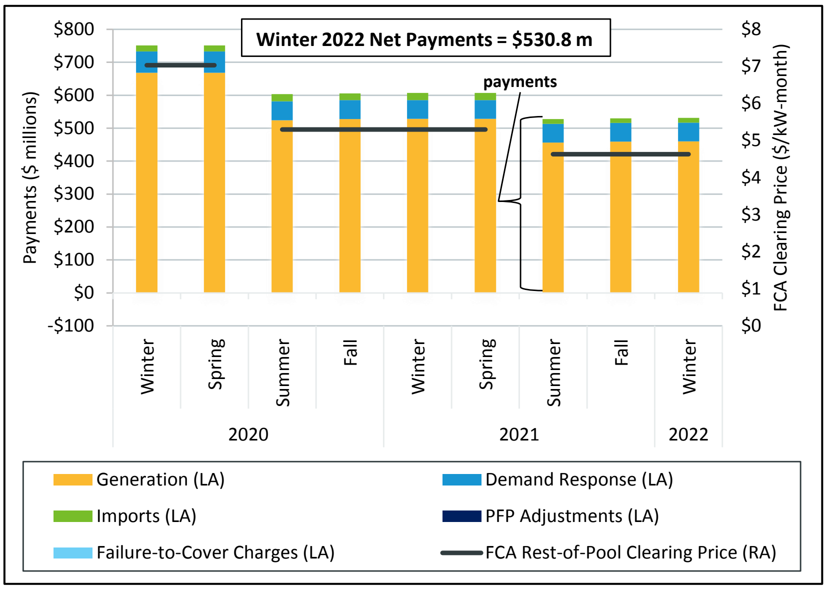
[89] In the capacity market, resource categories include generation, demand response and imports.

[90] 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.

zones within New England. Price separation occurred at two import interfaces, Phase I/II and 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 2020 through Winter 2022, are shown in Figure 7-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 7-1: Capacity Payments[91]



In Winter 2022, capacity payments totaled $530.8 million.[92] Total payments were down 13% from Winter 2021 ($607 million), driven by a 13% decrease in clearing price from FCA 11 ($5.30/kW-month) to FCA 12 ($4.63/kW-month).

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Winter 2022 alongside the results of the relevant primary FCA are detailed in Table 7-1 below.

[91] A failure-to-cover charge data error in December 2021 has not been reconciled at the time of publishing this report; failure-to-cover analysis has been omitted from the Winter 2022 report.

[92] 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.

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

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo) Phase I/II	Highgate	New Brunswick
FCA 12 (2021-2022)	Primary	12-month	4.63	34,828	3.70		3.16
	Monthly Reconfiguration	Feb-22	3.55	768		2.00	2.00
	Monthly Bilateral	Feb-22	2.38	600			
	Monthly Reconfiguration	Mar-22	0.85	909			
	Monthly Bilateral	Mar-22	0.93	106			
	Monthly Reconfiguration	Apr-22	0.53	726		0.50	0.50
	Monthly Bilateral	Apr-22	2.40	2			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions (MRAs) took place in Winter 2022: the February 2022 auction in December, the March 2022 auction in January, and the April 2022 auction in February. Clearing prices fell considerably from February to April, beginning at $3.55/kW-month in the February MRA and ending at $0.53/kW-month in the April MRA. A large demand bid set the abnormally high price in February; the resource did not continue the bidding behavior in the March and April auctions. In the February and April auctions, price separation occurred in the export-constrained capacity zone of Northern New England, decreasing clearing prices for capacity traded in the zone and along its interfaces. Cleared volumes remained relatively steady, with March clearing the largest volume at 909 MW.

7.2 Financial Transmission Rights

The purpose of Financial Transmission Rights (FTRs) is to provide market participants a way to hedge against, or speculate on, transmission congestion that occurs in the day-ahead energy market. Participants that expect to incur congestion charges from transacting in the day-ahead energy market may choose to purchase FTRs in order to receive revenue that can offset these charges. Alternatively, participants that do not transact in ISO-NE's energy markets may choose to acquire FTRs solely with the aim of realizing a profit. ISO-NE permits speculative trading of FTRs because of the increased liquidity and competition it brings to the market.

FTRs can be acquired in annual and monthly auctions, both of which have separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is limited by 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.

Target Allocations and Congestion Revenue

During an FTR's effective period (e.g., March 2022 on-peak hours), the ISO calculates credits/charges (generally referred to as *target allocations*) for the FTR on an hourly basis. This is done 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.[93] *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.

Payments to the holders of FTRs with positive target allocations come from the Congestion Revenue Fund (CRF). The money in this fund comes from three sources:

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

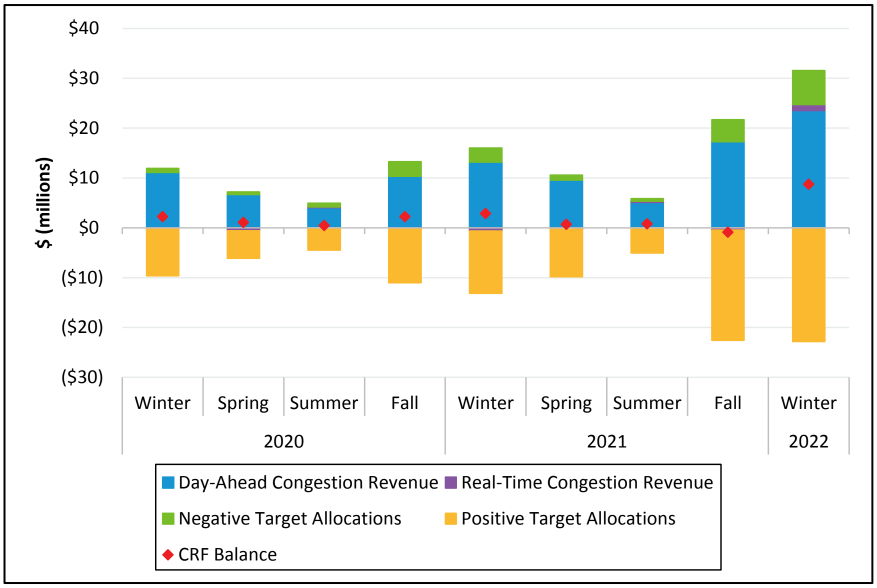
FTRs settle on a monthly basis. If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected 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 7-2 below, which shows, by quarter, (1) the amount of congestion revenue from the day-ahead energy market, (2) the amount of congestion revenue from the real-time energy market, (3) the amount of positive target allocations, (4) the amount of negative target allocations, and (5) the CRF balance.[94] 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.

[93] See ISO-NE Manual for Financial Transmission Rights (Manual M-06) and Section III.7 of ISO-NE Market Rule 1 for more information about FTRs.

[94] The CRF balances depicted in Figure 7-2 are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + |Negative\ Target\ Allocations|) - Positive\ Target\ Allocations$ and do not include any adjustments (e.g., surplus interest, FTR capping). 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 7-2: Congestion Revenue and Target Allocations by Quarter



In Winter 2022, day-ahead congestion revenue, real-time congestion revenue, positive target allocations, and negative target allocations were at their largest quarterly values of the nine quarters covered in this report. This was largely driven by the elevated energy prices in Winter 2022. As congestion components reflect the marginal values of binding transmission constraints, they tend to be higher when energy prices are higher.[95] To see this, we can consider an example of an export-constrained area where the marginal resource is setting the area's LMP at $0/MWh. If the marginal resource outside the export-constrained area is setting that area's price at $35/MWh, then the marginal value of the binding constraint would be -$35/MWh, reflecting the fact that if one more MW could flow over the binding constraint, then one MW priced at $35/MWh could be replaced by one MW priced at $0/MWh. It is straightforward to see that the marginal value of this binding constraint would double if the marginal resource outside of the export-constrained area were setting the price at $70/MWh instead of $35/MWh.

In Winter 2022, day-ahead congestion revenue amounted to $23.5 million. This represents an increase of 36% relative to Fall 2021 ($17.3 million) and an increase of 79% relative to Winter 2021 ($13.2 million). Meanwhile, real-time congestion revenue in Winter 2022 ($1.2 million) was generally the same order of magnitude as levels from Fall 2021 (-$0.5 million) and Winter 2021 (-$0.6 million). Positive target allocations in Winter 2022 ($22.8 million) followed a similar pattern to day-ahead congestion revenue, increasing by 3% relative to Fall 2021 ($22.1 million) and by 82% relative to Winter 2021 ($12.5 million). Similarly, there were elevated levels of negative target allocations in Winter 2022 ($6.9 million) compared to both Fall 2021 ($4.4 million) and to Winter 2021 ($2.9 million).

[95] The marginal value of a binding transmission constraint represents the impact on system production costs of allowing one more megawatt of energy to flow over that constraint.

Binding Transmission Constraints

Several of the more impactful transmission constraints in Winter 2022 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.

- **New England West-East (NE_WE)**: This interface constraint manages the power flow from western New England to eastern New England. As this interface essentially splits New England into two halves, it can meaningfully impact the target allocations for a large volume of FTRs when it becomes constrained. This interface bound periodically in the day-ahead energy market throughout Winter 2022, but most notably in December 2021 when transmission work reduced the limit of this interface over various periods.
- **New York – New England (NYNE)**: This interface constraint is used to manage the flow of power over seven AC transmission lines that interconnect the New York and New England control areas. Despite this interface being at its full operational capability for most of Winter 2022, it bound frequently in all three months. Congestion at this interface is quite common during the winter months when imports into New England tend to increase as the result of large spreads between power prices in New England and New York. In Winter 2022, the average day-ahead price at the New England Hub exceeded that for Zone G in New York by over $20/MWh.[96]

FTR Settlements

FTRs were fully funded in December 2021, January 2022, and February 2022. At the end of 2021, the congestion revenue fund had a surplus of $8.7 million. 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. In 2021, $1.7 million went to positive target allocations that had been underfunded during the year. The remaining $7.0 million was then allocated to those entities that had paid congestion costs during the year. At the end of February 2022, the congestion revenue fund had a surplus of $3.4 million.

[96] NYISO Zone G (also called Hudson Valley) is a load zone in the New York control area. See: https://www.nyiso.com/documents/20142/1397960/nyca_zonemaps.pdf

Appendix: Overview of FPA Process

Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that it differs significantly from the corresponding fuel index. As outlined in Section III.A.3.4(ii) of the Tariff, the submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer. When a participant submits an FPA, the IMM calculates the reference level for that resource using the cost-based methodology, which uses documented cost information provided by the participant to estimate incremental energy offers.[97] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[98]

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

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

While FPAs can be submitted for market days up to seven days in the future, they are most commonly submitted in association with offers into the day-ahead (DA) and real-time (RT) energy markets.[99] FPA requests for the DA market must be submitted by the close of day-ahead market window (10:00 AM Eastern Time), while FPA requests for the RT energy market can be submitted up to 30 minutes before the start of the operating hour in which they would take effect.

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

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

[97] See Tariff Section III.A.7.5.

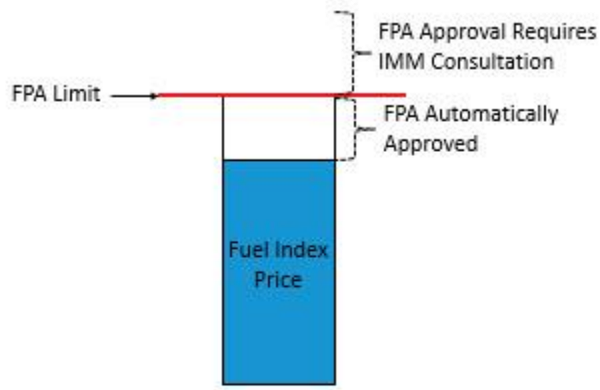
[98] Similar formulae are also used to estimate no-load and start-up costs, but are not shown here to preserve space.

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

from the Intercontinental Exchange (ICE), actual and forecasted weather, and generator gas consumption.

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

FPA Processing Overview



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