Winter 2021
Quarterly Markets Report

By ISO New England's Internal Market Monitor

APRIL 28, 2021

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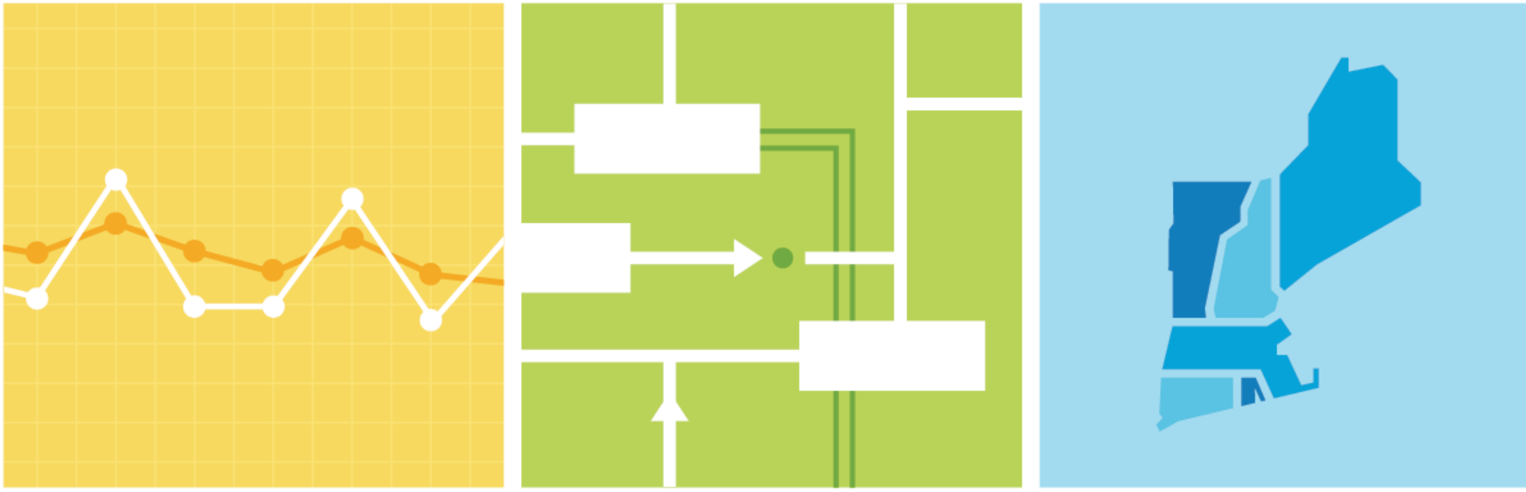

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Preface

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 2021 (December 1, 2020 through February 28, 2021).[3]

Fuel Markets and Weather: While no cold snap or extreme pricing occurred in Winter 2021, colder average temperatures resulted in higher natural gas prices compared to Winter 2020.

- In Winter 2021, temperatures averaged 31°F, a 2°F decrease compared to Winter 2020.
- Natural gas prices averaged $5.83/MMBtu in Winter 2021, up from $2.42/MMBtu during the previous winter.
    - February 2021 natural gas prices were particularly high, averaging $8.59/MMBtu, 88% higher than the average prices during December 2020 and January 2021. February 2021 temperatures averaged 29°F.
- The large increase in natural gas prices led to changes in the supply curve with the cost of gas-fired generation actually exceeding the cost of coal-fired generation, on average.
- Liquefied natural gas (LNG) injections in Winter 2021 were 29.5 million Dth, a 14% increase compared to Winter 2020. The increase was driven by higher levels of LNG injection from Canaport.

Energy Market Opportunity Costs: From December 2018, Energy Market Opportunity Cost (EMOC) adders for oil-fired generators were 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.[4]

During Winter 2021:

- Periods of very cold weather were not as extreme as in Winter 2018, but there was a sustained drop in average temperatures that was sufficient to produce non-zero EMOCs for two small generators. Smaller generators with limited storage or low inventory levels are more likely to have non-zero EMOCs during short cold snap events.
    - A 5 MW generator had non-zero EMOCs for seven days from February 6 through February 12. A second small generator (2 MW) had a non-zero EMOC on February 8.
    - The average daily temperature was just below 24°F for the seven days.
    - The average EMOC was $7.54 per MWh across the seven days.
- Episodes of very cold weather did not sustain long enough to put sufficient strain on the natural gas supply and, consequently, oil inventories.
- Large oil-fired generators (> 5 MW) had EMOCs equal to zero all winter, and no oil-fired generators were postured in Winter 2021.

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

The Fifteenth Forward Capacity Auction (FCA15): The fifteenth Forward Capacity Auction (FCA 15) was held in February 2021 and covers the capacity commitment period (CCP) beginning June 1, 2024 through May 31, 2025. 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 (40,540 MW) exceeded the Net Installed Capacity Requirement (33,270 MW) by 7,270 MW. The surplus decreased from FCA 14 (9,425 MW) as a result of a 780 MW addition to the NICR from the prior year.
    - System-wide surplus capacity cleared over 1,350 MW relative to NICR.
    - Varying capacity amounts in import- and export-constrained zones led to three levels of price separation. The Southern New England capacity zone cleared in the fourth round at $3.98/kW-month. The auction continued into the fifth round for the remaining capacity zones, and cleared at $2.61/kW-month for the Rest-of-Pool capacity zone and $2.48/kW-month for the Northern New England (Maine nested) capacity zone. Payments for FCA 15 ($1.4 billion) increased by 40% compared to FCA 14, driven by the higher clearing prices.
- Considering pre-auction mitigations, excess capacity, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 15.
- A total of 908 MW dynamically de-listed in rounds four and five; including 620 MW of gas-fired generation and 140 MW of oil-fired generation.
- New cleared capacity totaled 1,121 MW, primarily consisting of battery storage (596 MW), gas-fired generation (334 MW), and passive demand response (167 MW).
- The substitution auction following FCA 15 did not take place because no active demand bids cleared capacity in the FCA.

Wholesale Costs: The total estimated wholesale market cost of electricity was $2.33 billion, up 31% from $1.78 billion in Winter 2020. The increase was driven by higher energy costs in Winter 2021.

Energy costs totaled $1.71 billion; up 69% (or $699 million) from Winter 2020 costs. Higher energy costs were a result of higher natural gas prices, which increased by 71% relative to Winter 2020 prices.

Capacity costs totaled $607 million, down 19% (by $144 million) over the previous Winter. Beginning in Summer 2020, lower capacity clearing prices from the eleventh Forward Capacity Auction (FCA 11) contributed to lower wholesale costs relative to the previous FCA. Last year (CCP 10, June 2019 – May 2020), the clearing price for new and existing resources was $7.03/kW-month.[5] In the current capacity commitment period (CCP 11, June 2020 – May 2021), the clearing price for all new and existing resources was $5.30/kW-month. Lower clearing prices were partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slightly decreased Net ICR.

[5] Imports at the New Brunswick interface cleared slightly lower at $3.38/kW-month.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $51.30 and $51.66 per megawatt hour (MWh), respectively, a 69-72% increase compared to Winter 2020 prices.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $5.82/MMBtu in Winter 2021, up 71% compared to $3.40/MMBtu in the prior Winter.
- The spread between day-ahead LMPs and natural gas generation costs increased in Winter 2021 and Winter 2020 compared to Winter 2019, likely due to a decrease in baseload generation that occurred when a nuclear generator retired in June 2019.
- 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 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 payments totaled $9.6 million, a $2.2 million increase compared to Winter 2020 payments. Despite the increase in the total amount, NCPC payments represented less than 1.0% of total wholesale energy costs in both Winter 2021 and Winter 2020. The majority of NCPC (63%) was for first contingency protection ("economic" NCPC). The ISO paid out most of the first contingency payments in the real-time market.

At $3.0 million, local second-contingency protection (LSCPR) payments accounted for 31% of total NCPC payments. These payments increased by $0.3 million relative to Winter 2020. Most (54%) LSCPR payments occurred in December, and were paid to generators that were committed in the day-ahead market to meet reliability needs in Maine due to a planned transmission outage that lasted from mid-December through the first week of January.

Real-time Reserves: Real-time reserve payments totaled $2.1 million, up $0.3 million from $1.7 million in Winter 2020. All reserve payments were for ten-minute spinning reserve (TMSR).

The frequency of non-zero ten-minute spinning reserve pricing in Winter 2021 was similar to that of Winter 2020. The average non-zero hourly spinning reserve price increased relative to Winter 2020, from $7.56 to $9.75/MWh. The increase was due to higher LMPs, which increased re-dispatch costs to provide reserves rather than energy.

***Regulation*:** Total regulation market payments were $6.0 million, up 5% from $5.7 million in Winter 2020. The small increase in payments reflects a modest increase in regulation service prices and payments during the Winter 2021 period.

Financial Transmission Rights: Day-ahead congestion revenue totaled $13.2 million during Winter 2021, an increase of 19% from $11.1 million in Winter 2020. Positive target allocations in Winter 2021 ($12.5 million) also rose, increasing by 33% relative to Winter 2020. Negative target allocations in 2021 totaled $2.9 million, up significantly from Winter 2020 ($0.8 million). The increase was primarily due to the New England West-East interface constraint binding more frequently beginning in Fall 2020, after its limit was reduced to protect the system from a voltage issue.

In Winter 2021, real-time congestion revenue was negative, at -$0.6 million. Negative real-time congestion revenue was particularly pronounced in February 2021. On February 10, there was almost $1.0 million of negative real-time congestion as a result of a line trip in the New York control area that led to reduced transfer limits at the New York North interface. Partly as a result of this negative real-time congestion, the FTRs for February 2021 were not fully funded, and FTR holders with positive target allocations received only 95% of the revenue to which they were entitled. Recently, it has not been uncommon to see negative real-time congestion revenue. However, there was a congestion revenue fund surplus in January 2020 ($1.1 million). Surpluses are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations.

Section 2
Assessment of Winter 2021 Market Issues

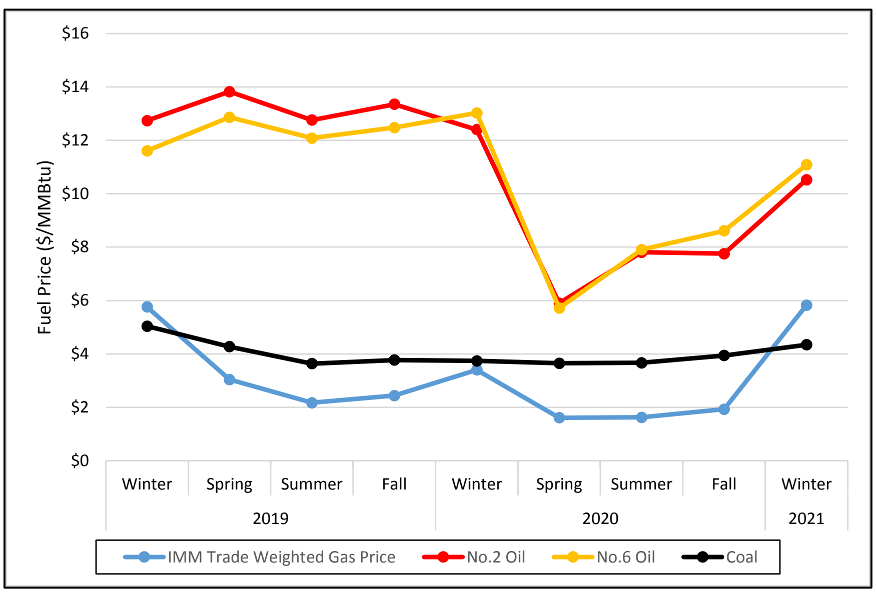
This section focuses on a number of issues in the New England markets specific to winter; a season when the natural gas system can become constrained due to high heating demand for gas. The first two subsections provide observations on fuel prices while the third subsection reviews Energy Market Opportunity Costs (EMOCs).

2.1 Fuel Markets and Weather

During winter in New England, cold weather can cause natural gas pipelines to become constrained, giving rise to extremely high natural gas prices. For instance, the "cold snap" in Winter 2018 led to constrained natural gas pipelines and gas prices reached a daily high of nearly $62/MMBtu. This pushed gas-fired generators up the supply stack and out of economic merit order. While no extreme natural gas pricing occurred in Winter 2021, colder average temperatures resulted in higher natural gas prices than in Winter 2020.

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 2-1 below.

Figure 2-1: Fuel Prices

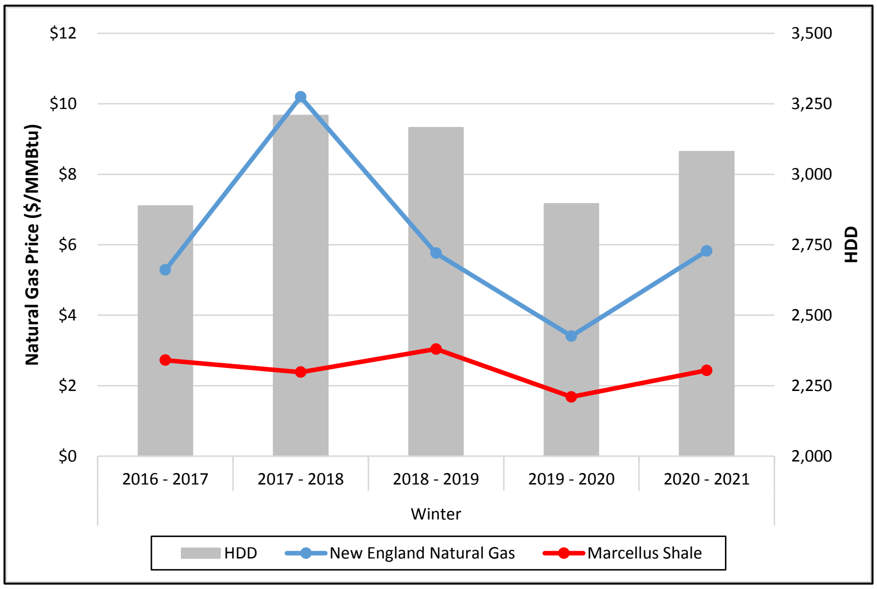


Compared to Winter 2020, average prices increased for natural gas (71%) and coal (16%), but decreased for No.2 oil (15%) and No.6 Oil (15%). The large increase in natural gas prices led to gas-fired generation ($45.44/MWh) being more expensive than coal-fired generation ($43.46/MWh), on average.[6]

[6] Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7.

Natural Gas: In Winter 2021, natural gas prices averaged $5.83/MMBtu, a 71% (or $2.42/MMBtu) increase compared to Winter 2020, and a 1% ($0.07/MMBtu) increase compared to Winter 2019. Colder temperatures drove higher heating demand for natural gas leading to higher natural gas prices. Figure 2-2 illustrates the average New England natural gas price (blue) compared to average Marcellus Shale region natural gas price (red) over the previous five winters. Heating degree-days (gray) are shown in the bar charts on the secondary axis.

Figure 2-2: New England Winter Natural Gas Price, Marcellus Shale Prices and Heating Degree Days



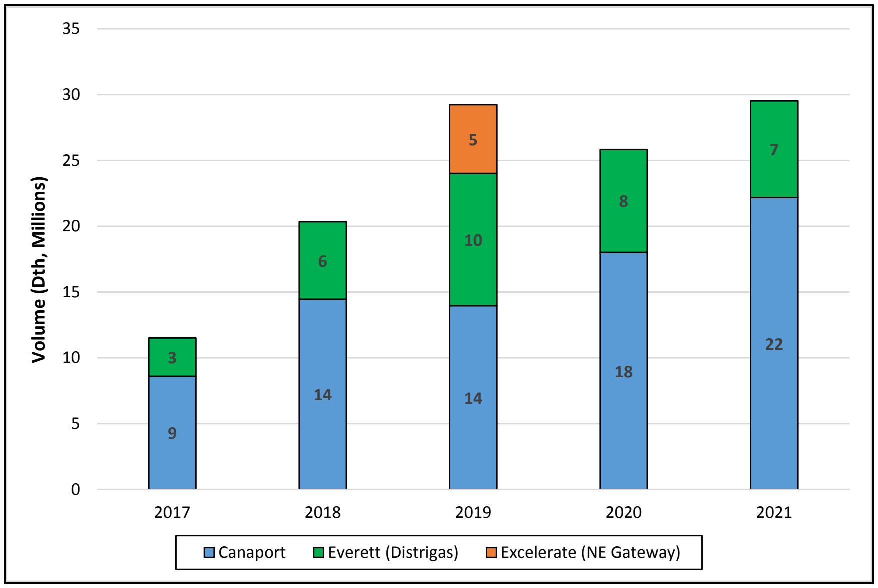
During the winter, cold weather drives natural gas prices in New England. When temperatures fall, the natural gas infrastructure can become constrained and natural gas-fired generators must compete for fuel against heating demand. In Winter 2021, temperatures averaged 31°F, a 2°F decrease compared to Winter 2020 (33°F). This caused higher natural gas prices in Winter 2021 ($5.83/MMBtu) compared to the prior winter ($3.41/MMBtu). New England natural gas prices were particularly high in February 2021, averaging $8.59/MMBtu, or 88% higher than the average prices during December 2020 and January 2021 ($4.58/MMBtu). During February 2021, temperatures averaged 29°F compared to an average of 32°F during the rest of the season.

Since New England has no native natural gas production, natural gas prices at supply basins directly influence New England natural gas prices. In Winter 2021, natural gas prices increased year-over year at different supply basins. At Henry Hub, natural gas prices increased $1.35/MMBtu, or 67% year-over-year, largely due to record high prices during a "cold snap" throughout the Midwest and Texas. Natural gas prices at Henry Hub reached over $23/MMBtu as nationwide natural gas withdrawals nearly broke all-time records.[7] In the Northeast, natural gas prices increased during this period but not as much as natural gas prices at Henry Hub. In the Marcellus Shale region, daily natural gas prices increased during the "cold snap" but never surpassed $6.00/MMBtu. Overall, natural gas prices in the Marcellus Shale region increased by $0.75/MMBtu, or 45% compared to Winter 2020.

[7] See the EIA Natural Gas Weekly 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 which can help alleviate constraints and subsequently reduce gas prices. There are three operational LNG import facilities that deliver gas into New England: Excelerate, Canaport and Everett (Distrigas).[8] The volume of deliveries into each facility for the past five winters is illustrated in Figure 2-3 below.

Figure 2-3: LNG Sendout by Facility[9]



Outside of Winter 2017, New England has seen at least 20 million Dth of LNG deliveries into the interstate natural gas pipelines each winter. LNG injections in Winter 2021 were 29.5 million Dth, a 14% increase compared to Winter 2020 and a 1% increase compared to Winter 2019. Higher levels of LNG injection from Canaport drove the overall LNG delivery increase. LNG injection from the Everett (Distrigas) facility fell year-over-year (7.8 million to 7.3 million Dth) while the Excelerate buoy received no LNG shipments during the most recent winter. Overall, the increase in LNG in Winter 2021 resulted in 3.7 million Dth more of LNG supply, or enough natural gas to power a nearly 220 MW gas-fired generator for the entire winter.[10]

2.2 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 2021. 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

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

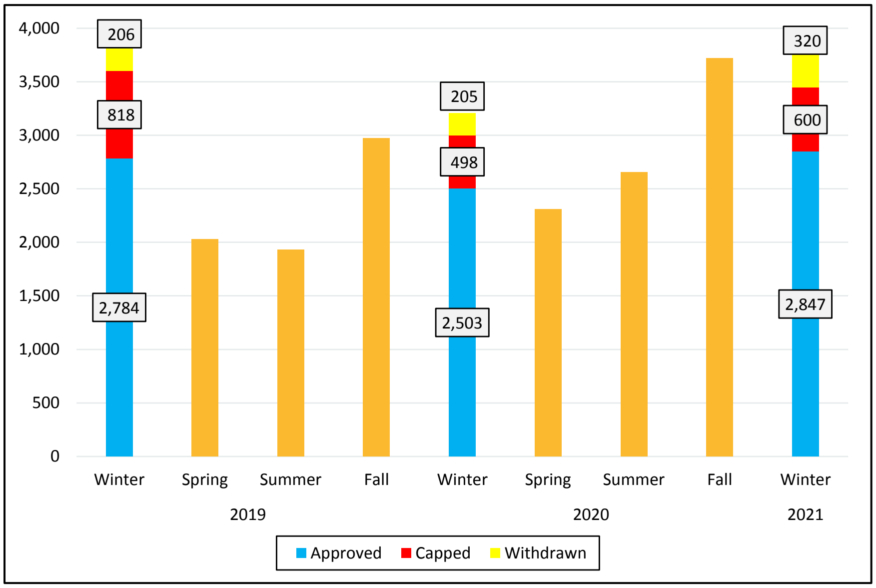
[9] LNG delivery data is sourced from Genscape.

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

reasonable upper bound for natural gas prices ("FPA Limit").[11] For more details on how FPAs are processed, see Appendix: Overview of FPA Process, at the end of this report.

As seen in Figure 2-4, the number of FPA requests spike in the winter periods, averaging 1,100 requests more than the other periods. In addition, the number of FPA requests this winter increased to about 3,800 from around 3,200 requests in Winter 2020. On average, approximately 76% of FPA requests were approved over the last three winter periods.[12]

Figure 2-4: FPA Requests, by Year, Season, and Status



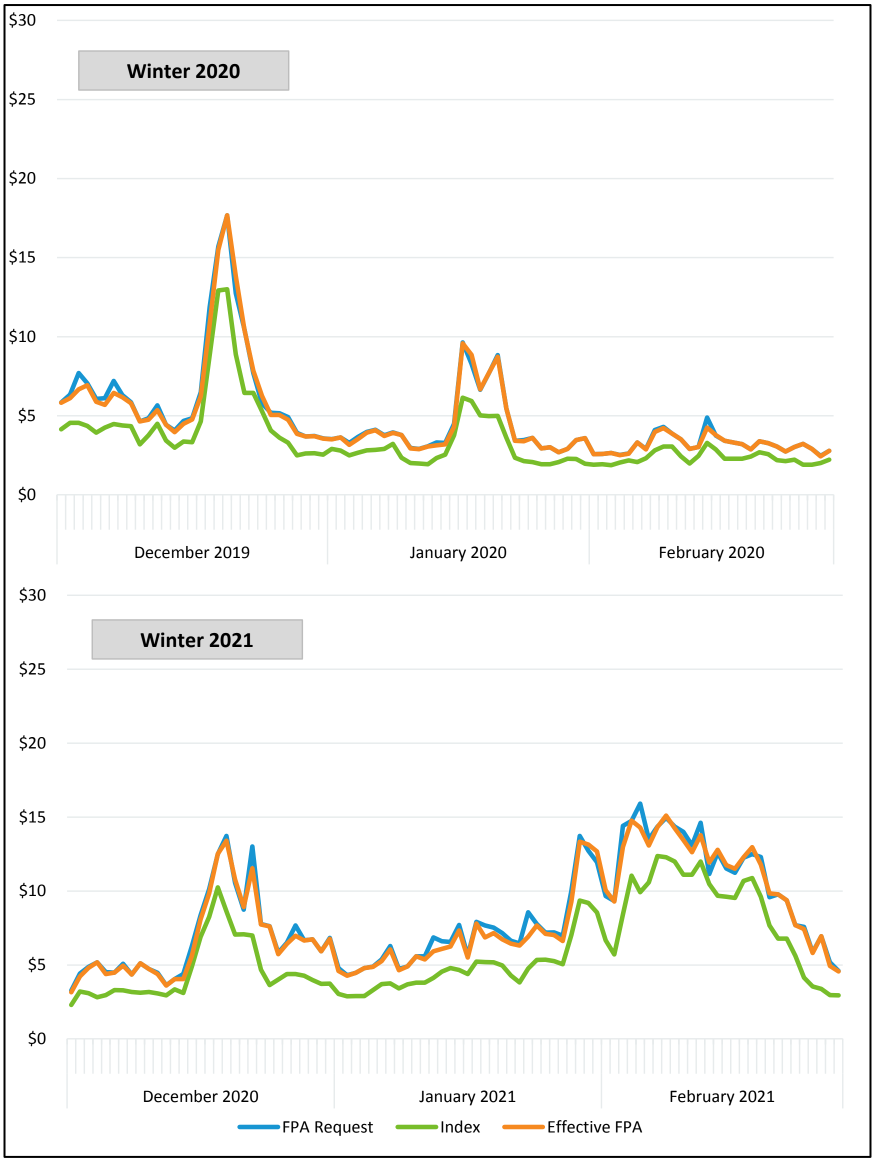
In Winter 2021, the IMM received FPA requests from 21 participants for over 60 generators, which is in line with Winters 2019 and 2020. There were more submitted and accepted FPAs in Winter 2021 compared to 2020, primarily due to higher index prices in Winter 2021. The following figure shows the average settled index price for natural gas, requested FPA prices, and effective FPA price on a daily basis for the last two winter periods.[13] Because there are no volumes associated with FPA requests, the prices are calculated 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.

[11] 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.)

[12] This breakout is not shown for the non-Winter quarters.

[13] 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).

Figure 2-5: Average Index Price, FPA Request, and Effective FPA



In Winter 2021, the average FPA request was approximately 71% higher than the settled fuel index price for the corresponding market day. While 16% of submitted FPAs were capped in the Winter 2021 period, the cumulative effect of the capping was small as effective FPAs corresponded to approximately 98% of the requested values. Similarly, the magnitude of the capping effect was more pronounced at greater price levels. Finally, as no participant violated the Tariff relating to FPA requests, no resource was locked out from using the FPA mechanism during Winter 2021.

2.3 Energy Market Opportunity Cost

Winter 2020 produced the first non-zero EMOCs (Energy Market Opportunity Costs) since their implementation. On December 1, 2018, energy market reference levels began including an opportunity cost (EMOC) adder for resources that maintain an oil inventory.[14] The update was motivated by concerns that, during sustained cold weather events, generators were unable to make energy supply offers that incorporated opportunity costs associated with the depletion of their limited fuel stock. 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 a generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and 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,(e.g., gas and oil price forecasts, fuel inventory levels and generator characteristics) it is possible to 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 to gas prices for a long enough period to physically exhaust the oil-fired generator's 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.

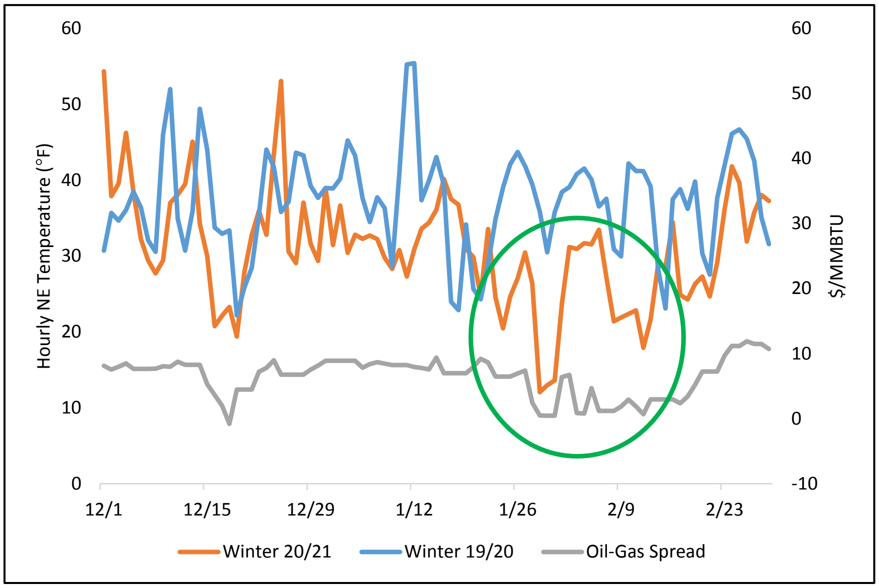
Winter 2021 did not have a cold snap as extreme as in Winter 2018, but there was a sustained drop in average temperatures that was sufficient to produce non-zero EMOCs for two small generators.

- One small generator (5 MW) had non-zero EMOCs for seven days from February 6 through February 12.
- A second small generator (2MW) had a non-zero EMOC on February 8.
- The average daily temperature was just below 24°F for the seven days.
- The average EMOC was $7.54/MWh across the seven days.

New England average daily temperatures for Winter 2020 and Winter 2021 are shown in Figure 2-6 below. Winter 2020 was generally milder than this past winter and did not have any extended cold spells. By contrast, Winter 2021 had one short-lived cold snap (highlighted by the green circle) which narrowed the spread between oil and gas prices close to parity.

[14] 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

Figure 2-6: Average Daily New England Temperatures Winter 2020 and Winter 2021



Smaller generators with limited storage or low inventory levels are more likely to have non-zero EMOCs during a short cold snap event, like the type that occurred in February 2021. Larger generators with ample inventory would require a longer cold snap to create EMOCs from the tradeoff between using the oil now or using it later for a potentially higher profit. During Winter 2021, episodes of very cold weather did not sustain long enough to put sufficient strain on the natural gas supply and, consequently, oil inventories. In addition, with the implementation of EMOCs, we expect that no large oil-fired generators would be postured by the ISO during winter, instead participants should use EMOCs to manage their inventories. This winter, no oil-fired generators were postured.

Section 3
Review of the Fifteenth Forward Capacity Auction

This section presents a review of the fifteenth Forward Capacity Auction (FCA 15), which was held in February 2021 and covers the capacity commitment period (CCP) beginning June 1, 2024 through May 31, 2025. 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 15 outcomes. At the beginning of the auction, qualified capacity (40,540 MW) exceeded the Net Installed Capacity Requirement (33,270 MW) by 7,270 MW. The surplus decreased from FCA 14 (9,425 MW) as a result of a 780 MW addition to the Net Installed Capacity Requirement (NICR) from the prior year. System-wide surplus capacity cleared 1,350 MW above NICR. Varying capacity amounts in import- and export-constrained zones led to three levels of price separation:

- Southeastern New England at $3.98/kW-month (fourth round).
- Rest-of-Pool at $2.61/kW-month (fifth round).
- Northern New England at $2.48/kW-month (fifth round).

Payments for FCA 15 ($1.4 billion) increased 40% from FCA 14, driven by higher clearing prices across the system.

In FCA 13, Mystic 8 and 9 were retained for fuel security within the Southeastern New England capacity zone, and entered into a cost-of-service agreement with the ISO.[15] The agreement suggests that the FCA could not facilitate an efficient *and* reliable solution. In FCA 15, the cost-of-service agreement ended due to accepted transmission proposals and updated fuel security reviews, allowing Mystic 8 and 9 to retire effective June 1, 2024.[16] The end of the agreement was reflected in a 1,400 MW loss of qualified capacity in the Southeastern New England capacity zone.

A total of 900 MW dynamically de-listed in rounds four and five; including 620 MW of gas-fired generation, and 140 MW of oil-fired generation. New cleared capacity totaled 1,120 MW, primarily consisting of battery storage (600 MW), gas-fired generation (330 MW), and passive demand response (170 MW). Only 19 MW remained in the renewable technology resource (RTR) exemption for FCA 15, closing a critical avenue for wind and solar projects to enter the capacity market when they might not otherwise clear due to their costs.[17] The substitution auction following FCA 15 did not take place because no active demand bids cleared capacity in the FCA.

[15] For more information on the fuel security order see: https://www.iso-ne.com/static-assets/documents/2018/12/fuel_security_order.pdf

[16] 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

[17] The RTR designation allows a limited amount of renewable resources to participate in the auction without being subject to the minimum offer-price rule. The introduction of the Competitive Auctions with Sponsored Policy Resources (CASPR) substitution auction in FCA 13 sparked the sunset of the RTR exemption.

3.1 Review of FCA 15 Competitiveness

We review competitiveness before and after the primary auction occurs. Prior to the auction, we may mitigate bids and offers for various reasons described below. After the auction, we review participant behavior, the presence of market power, and whether 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 15.

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. 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.[18] We either replace the out-of-market revenues with market-based revenues or remove them entirely, and we recalculate the offer to a higher, competitive price (i.e., the offer is mitigated). In FCA 15, we reviewed 116 resources from 22 participants, accounting for 2,443 MW of capacity.[19] The difference between the MW-weighted average submitted price ($1.52/kW-month) and the price that went into the auction ($4.68/kW-month) for resources that we mitigated highlights the degree to which the buyer-side market power mitigation measures protect price formation from the price-suppressing effects of out-of-market revenues.

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.[20] In FCA 15, we reviewed 800 MW of general static de-list bids from five resources. We denied the price of one of the bids. The denied bid accounted for 664 MW, or 83%, of general static de-list bids. The magnitude of general static de-list price differences (exclusive of imports) reflected a change of average price from $7.65/kW-month to $6.40/kW-month. 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 found to be pivotal (described below).

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

[19] 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.

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

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 fulfill demand even 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 15, 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 98%, down slightly from the high of 103% in FCA 14. A higher Net ICR cut into the pre-auction supply margin. For the SENE capacity zone, the FCA 15 RSI dropped to 79% from the FCA 14 value of 93%. The removal of Mystic 8 and 9 resulted in a negative supply shift that decreased the zonal capacity margin to below the LSR.

3.1.4 Pivotal Supplier Test

We use a Pivotal Supplier Test (PST) to determine which, if any, suppliers of capacity may have the ability to exercise seller-side market power.[21] A supplier is deemed pivotal if, after removing the entirety of their capacity, the respective zone is unable to meet its corresponding capacity requirement.[22] 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.[23]

For FCA 15, 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 1,922 MW; no suppliers met this criterion at the system level. At the zonal level, Southeastern New England entered the auction with less effective capacity (9,594 MW) than the Local Sourcing Requirement (10,305 MW). Therefore, all 58 suppliers in the region were pivotal in the auction and any static de-list bids submitted would have been mitigated down to an IMM-determined price. Only one of the suppliers in SENE submitted a static de-list bid, and it was withdrawn prior to the auction.

3.1.5 Intra-Round Activity

The pivotal supplier test above is limited to pre-auction calculations; once the auction begins, excess supply starts to decrease system-wide and additional suppliers can become pivotal. The fourth and fifth rounds of the auction were conducted below the dynamic de-list bid threshold (DDBT). Under the Tariff, the IMM does not review bids from existing resources below the DDBT, a proxy price intended to represent the net going forward costs of the likely marginal resource.

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[21] 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.

[22] 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.

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

Southeast New England entered the fourth round with an excess of 738 MWs. Eight suppliers had portfolios larger than this margin entering the round.[24] Of these, none submitted dynamic de-lists, and one offered their new capacity down to their IMM-reviewed offer floor price. Additionally, approximately 90% of the price-sensitive capacity in the round came from new supply, which is subject to our review.

The system entered the fifth round with an excess of approximately 1,246 MWs. Twenty-five participants had price-sensitive capacity (in the form of withdrawn supply or dynamic de-lists) in this round, totaling over 4,300 MWs. The supply curve in this round was relatively flat, which would make it difficult for a market participant to profit from economic withholding given the small impact that would have on clearing prices.

More specifically, eight suppliers had portfolios larger than the 1,246 MW margin entering the round.[25] Four of these suppliers offered price-sensitive capacity in this round and one had more than the capacity margin. To assess the potential impact of the activity taken by this supplier, we recalculated the supply curve without the participant. If the supplier withdrew their de-list bids from the final round, the resulting binding price would have decreased slightly and the supplier's gross profit would have increased due to greater capacity remaining in the auction. The results demonstrate the supplier's activity did not negatively alter the outcome of the auction.

3.1.6 Battery Resource Price Analysis

This section provides a detailed overview of supply offers associated with new battery resources over the past three Forward Capacity Auctions (FCA 13 through FCA 15).[26] More specifically, it examines prices at three particular milestones: 1) offer floor price requests from resources challenging their Offer Review Trigger Prices (ORTPs) at the starting price; 2) price determinations made by the IMM (i.e., the "mitigated price"); and, 3) the price associated with the resource during the actual Forward Capacity Auction (FCA). This analysis categorizes the batteries into two groups: 1) stand-alone batteries, and 2) batteries paired with solar PV ("co-located batteries").[27]

Between FCAs 13 and 15, we received 123 new supply offers from participants requesting to offer battery resources below the ORTP. These offers came from 15 different lead participants and totaled 4,570 MWs of capacity. We categorized the majority of the projects (69%) as co-located, but a significant majority of total project capacity was categorized to stand-alone projects (97%).

Summary statistics for battery projects from FCAs 13 through 15 are provided in Figure 3-1 below. Note that all offer prices are megawatt-weighted averages, expressed in dollars per

[24] Many of the same resources roll up into multiple supplier portfolios.

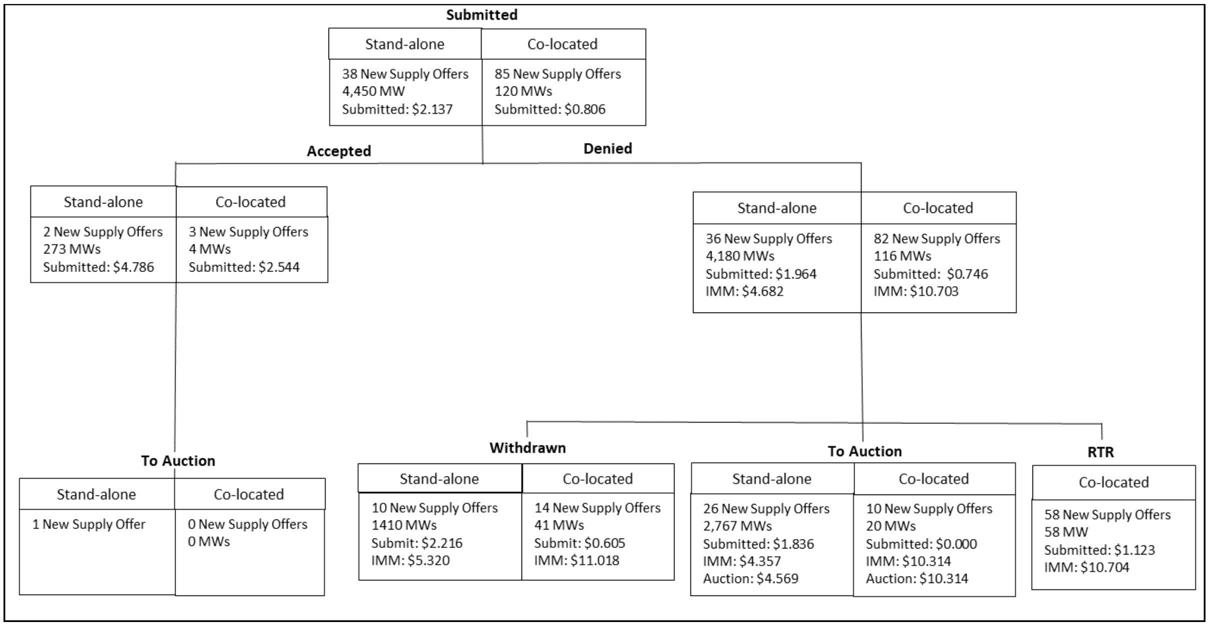
[25] These totals do not include Southeast New England capacity; and, again, many of the same resources roll up into multiple supplier portfolios.

[26] To avoid introducing bias in the analysis, the data do not include offers from resources for incremental battery capacity (i.e., additions to capacity that has cleared a prior FCA).

[27] In addition to differences in costs, revenues, and operations, we have made this distinction because of known state-sponsored out-of-market revenues for these resources (*e.g.*, Solar Massachusetts Renewable Target) program.

kilowatt-month. All offers were submitted to the IMM for review; denied offers were then given an IMM-determined price and the following options: 1) withdraw the offer, 2) go into auction with the mitigated price, or 3) for co-located resources, go into auction with the Renewable Technology Resource (RTR) exemption.

Figure 3-1: Battery Resource Prices, by Key Milestone



We mitigated approximately 96% of the new supply offers we reviewed, or approximately 94% of new supply capacity (as indicated in the right-hand side of the figure). The impact of mitigation can be measured using the relative increase in the offer floor price imposed by the IMM. For stand-alone batteries, mitigation increased average offer prices by $2.898/kW-month (from a submitted price of $1.964/kW-month to an IMM-determined price of $4.682/kW-month).[28] For co-located batteries, mitigation increased average offer prices by $9.957/kW-month (from a submitted price of $0.746/kW-month to an IMM-determined price of $10.703/kW-month). In the auction, the stand-alone batteries offered only $0.21/kW-month above their IMM-determined values, while the co-located offered at their IMM-determined values.

3.2 Auction Inputs

FCA 15 was the second 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.[29] 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-

[28] The average requested offer floor price has decreased from $3.429/kw-month in FCA13 to $1.578//kw-month in FCA15.

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

shaped MRI curve.[30] The transitional curve adopted a “shelf”, which is discussed in more detail below.

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.[31] 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 reference technology for FCAs 12 through 15 reflects costs of a combustion turbine ($8.71/kW-month in FCA 15), which was selected as the most economically efficient resource the ISO reviewed.[32] The Net ICR value for FCA 15 was 33,270 MW, or 780 MW higher than in FCA 14. The increase was primarily due to the introduction of transportation and heating electrification in peak load forecasts.[33]

The Net ICR increase was the first seen since FCA 9, resulting in an outward shift of the demand curve compared to prior auctions. The difference between demand curves and qualified capacity for FCAs 13, 14, and 15 are shown in Figure 3-2 below.

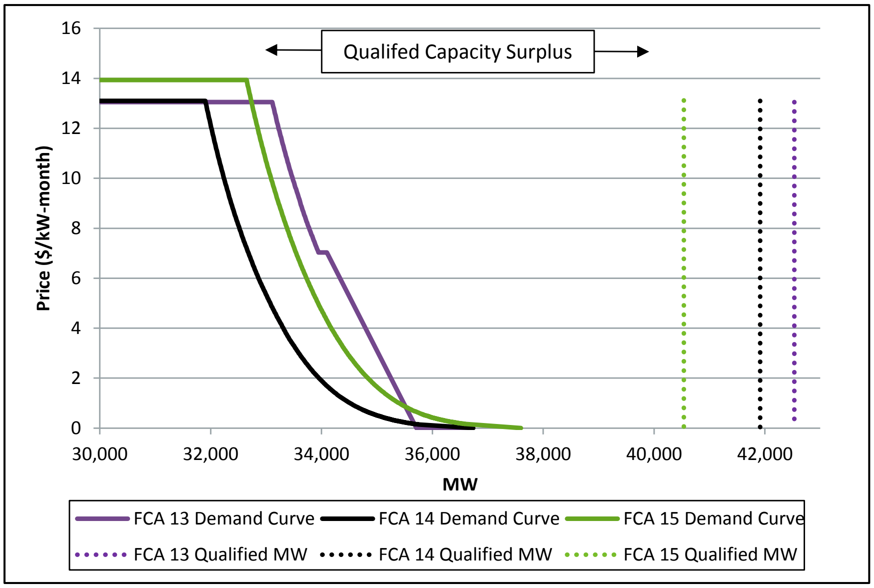
[30] The transition period begins with FCA 11 and can last for up to three FCAs, unless certain conditions relating to Net ICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

[31] 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”.

[32] 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).

[33] For more information see https://www.iso-ne.com/static-assets/documents/2020/11/icr_for_fca_15.pdf

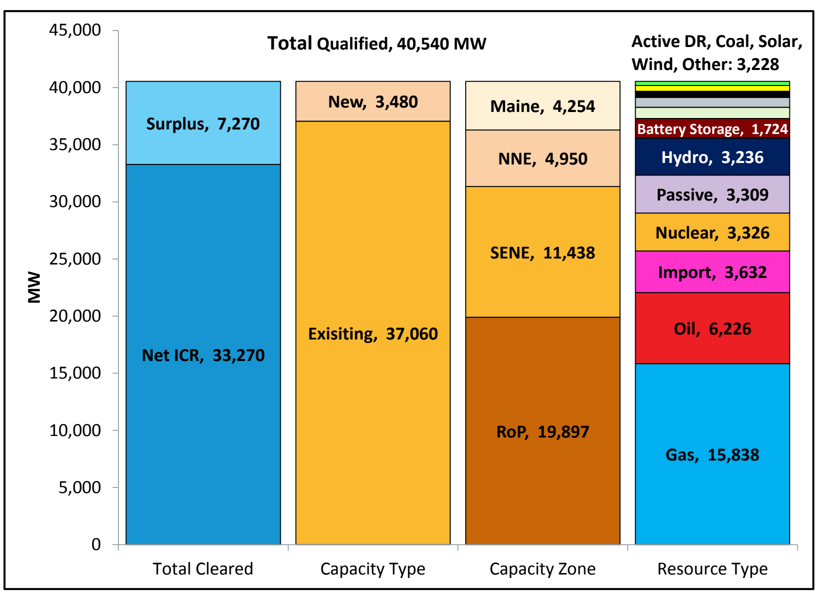
Figure 3-2: Net ICR and System Demand Curves



Compared to FCA 14, lower qualified capacity and an outwardly shifted demand curve led to smaller capacity surpluses in FCA 15. The former shift in qualified supply was due in part to the removal of Mystic 8 and 9, over 1,400 MW of generation located in Southern New England. With an outward shift in demand and a significant departure of existing generation, one might expect higher capacity prices in FCA 15 compared to FCA 14.

As mentioned above, the amount of qualified capacity can play an important role in auction outcomes. Figure 3-3 below shows that participants provided 40,540 MW of qualified capacity in FCA 15. The three bars to the right show the breakdown of total qualified capacity across three dimensions: capacity type, capacity zone and resource type.

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



Overall, in FCA 15, qualified capacity exceeded Net ICR by 7,270 MW, or almost 22%. New qualified capacity totaled 3,480 MW, an increase of over 500 MW from the FCA 14 value (2,950 MW. Battery storage projects provided the largest share of new qualified capacity with over 1,700 MW.

The first orange bar (by Capacity Type) shows that the qualified capacity from existing resources exceeded the Net ICR by less than 3,800 MW.[34] Prior to the qualification process for FCA 15, the ISO determined that new transmission projects and updated fuel security reviews removed the reliability need for Mystic 8 and 9 and their 1,400 MW of existing capacity in SENE.[35]

The second orange bar (by Capacity Zone) shows the 11,438 MW of qualified capacity in SENE which exceeded the Local Sourcing Requirement (LSR) by roughly 1,100 MW. The Northern New England (NNE) capacity zone had 9,204 MW of qualified capacity, 500 MW more than the maximum capacity limit (MCL), indicating an excess over the maximum amount of capacity that could be purchased in the zone. Maine, modelled as an export-constrained zone nested within NNE, had 4,254 MW of qualified capacity, slightly over the MCL of 4,145 MW. 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

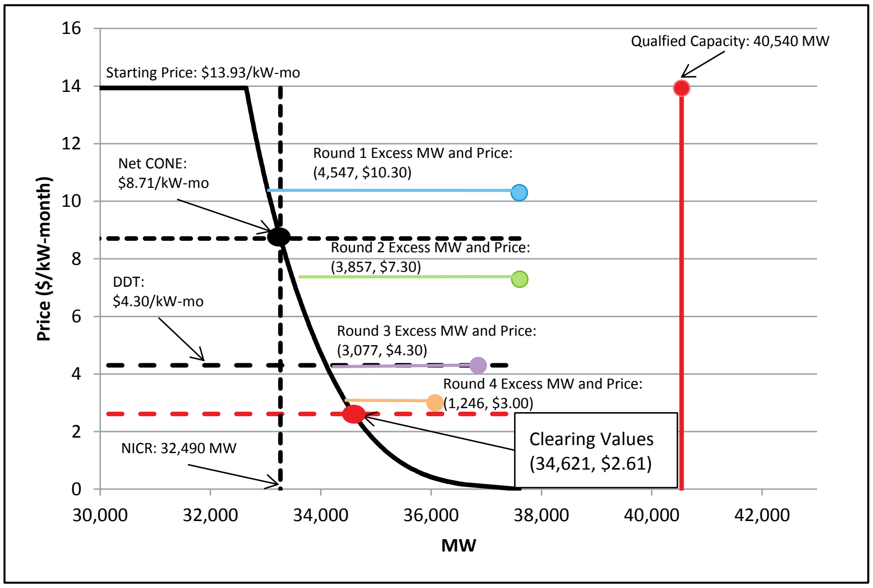
In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. These factors, which include the auction parameters provided by the ISO as well as participant behavior, are summarized in Figure 3-4 below. On the *demand* side, 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 $2.61/kW-month can be seen at the intersection of the cleared MW (dotted red line) and the demand curve (solid black line), below the Dynamic De-list Bid Threshold (DDBT) price of $4.30/kW-month (black dashed line). Lastly, the blue, green, purple, and orange markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.[36]

[34] 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 14 that increased New England's import capability. Treating imports elsewhere classified as "new" would conflate the actual amount of new capacity on the system. The capacity of an oil-fired resource in Southeast New England (SENE) is not included as qualified capacity because the resource's retirement de-list bid was above the starting price.

[35] 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

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

Figure 3-4: System-wide FCA 15 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for the Southeastern New England capacity zone and in the fifth round for remaining capacity zones: the Rest-of-Pool and Northern New England (Maine nested). The fourth round opened with 3,077 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.[37]

In the fourth round, only 678 MW of existing resources submitted de-list bids. In the Southeastern New England zone, a new supply offer priced at $3.98/kW-month would have left zonal supply short of zonal demand if withdrawn; the import constraint bound and resulted in a $3.89/kW-month clearing price. The auction continued into the fifth round, without any bids or offers from SENE, with an excess supply of 1,246 MW.

In the fifth round, existing resources submitted 2,812 MW of de-list bids, and 195 MW of new supply submitted offers to exit the auction. For the Rest-of-Pool capacity zone, a rationable dynamic de-list bid at $2.61/kW-month would have left system supply short of system demand if fully cleared. The bid was partially cleared to its rationing minimum limit and the Rest-of-Pool clearing price was set to $2.61/kW-month.[38] Finally, the Northern New England (Maine nested) capacity zone cleared when a dynamic de-list bid priced at $2.48/kW-month would have left zonal supply short of zonal demand, resulting in a final zonal clearing price of $2.48/kW-month.

3.3.1 Results of the Substitution Auction (CASPR)

For the past three years, the Competitive Auctions with Sponsored Policy Resources (CASPR) initiative has been in effect for the Forward Capacity Auction. The ISO implemented CASPR to

[37] 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.

[38] Rationability refers to a resource's ability to clear within a range of a capacity. A non-rationable resource either clears all or none of their offer segment. The rationing minimum limit represents the minimum amount of capacity a rationing resource is willing to clear.

address two issues: 1) consumers may end up paying for capacity through both the FCM and through subsidies for state-mandated new supply resources, and 2) capacity market prices could be depressed below competitive levels if a large quantity of unmitigated new subsidized resources enter the market.

CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. The fundamental component of CASPR is the Substitution Auction (SA) that takes places promptly after the primary FCA and serves to coordinate the entry of subsidized new resources with the exit of existing capacity resources. In the substitution auction, existing capacity resources that retained capacity obligations in the primary FCA and 'opted in' to the SA may transfer their obligations to new resources that did not clear in that first stage because of the Minimum Offer Price Rule (MOPR). The SA clearing price can be positive or negative. When the price is positive, existing resources pay the subsidized new resources for accepting capacity obligations and they retain the difference between what they receive as a CSO payment and what they pay the subsidized resources to assume the obligations. If the SA price is negative, then the subsidized resources are willing to pay to take on the obligation for the first year, which would be offset by positive capacity payments in future years when they would be treated as existing capacity. Either way, the existing resources that transfer their obligations in the SA retire from the FCM permanently.

Unlike the FCA in which the ISO must procure sufficient capacity to meet capacity targets, the quantity of capacity that clears the SA is dependent on the amount of capacity offered by existing participants and the quantity demanded by new entrants. In FCA 13, the SA cleared 54 MW at a price of $0/kw-month. One participant shed their obligation of 54 MW, which was obtained by a new entrant seeking to acquire up to 273 MW of capacity obligation. An additional 271 MW of supply offers that had elected to participate in the SA were removed before the SA because either they cleared in the FCA, or their offer price was greater than the FCA clearing price, i.e., existing capacity would have to pay them more than the FCA price to take on their obligation.

It is possible that a participant would be willing to accept a lower FCA clearing price than their true cost of obtaining a CSO if they believe it would gain them entry to the SA where they would buy out of their obligation. This behavior could suppress FCA clearing prices as the subsidy is seen to move backward from the SA auction into the primary FCA. Beginning in FCA 14, an estimate of the true cost of obtaining a CSO, known as a test price, was calculated for each demand resource and any resource whose test price is above the FCA clearing price was excluded from the SA.

This year, for the second year in a row, the substitution auction did not proceed. In FCA 15, there were 229 MW of subsidized supply seeking to acquire capacity obligations, but only one demand (existing) resource with a capacity of 94 MW had opted to participate in the substitution auction. However, this resource was unable to obtain a CSO in the primary auction and, consequently, had no obligation to trade in the substitution auction.[39]

Clearly, a primary driver for the level of demand in the substitution auction is FCA price. Very low FCA prices make it impossible for resources that are approaching retirement to obtain a CSO in the first place. Such resources face the choice of playing a waiting game for prices to rise or to retire unconditionally. Currently, the system is long on capacity and this is reflected in

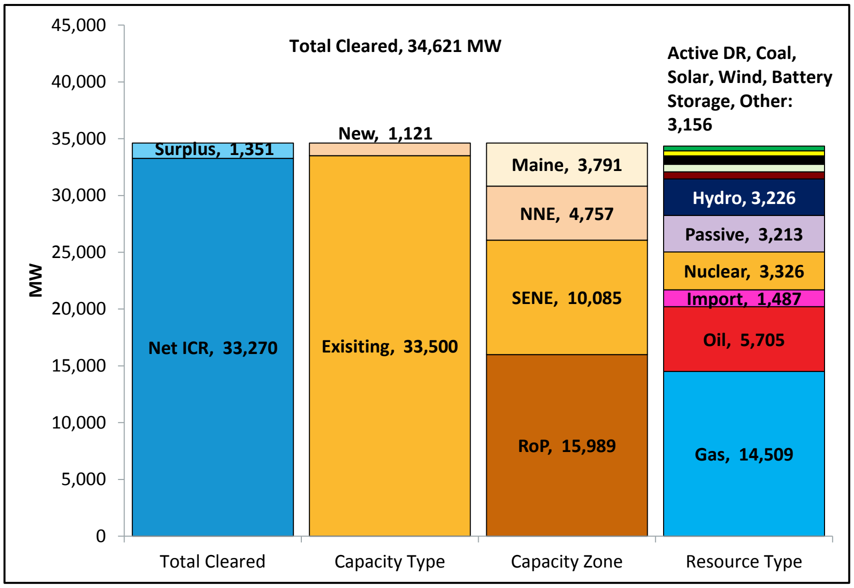
[39] For more information on test prices, see Section 6.7.2 of the 2019 AMR.

relatively low capacity prices when compared with prior years. These low FCA clearing prices signal to the market that neither the resources close to retirement nor the sponsored resources seeking entry are needed to satisfy system demand. However, when capacity prices rise, we expect to see renewed interest in CASPR from resources that are approaching retirement in the near future.

3.4 Cleared Capacity

The amount of cleared capacity across several dimensions including capacity type, capacity zone, and resource type is shown in Figure 3-5 below. The height of each grouping equals total cleared capacity. As indicated, the amount of cleared capacity in FCA 15 exceeded system-wide requirements.

Figure 3-5: Cleared Capacity across Capacity Type, Zones, and Resource Type



As excess supply declined during the auction, total surplus fell from 7,270 MW of qualified capacity to 1,351 MW of cleared capacity. The 5,919 MW difference stems from existing resources de-listing, and new supply resources exiting the market at prices greater than the $2.61/kW-month clearing price. The first orange bar (capacity type) illustrates that existing capacity accounted for almost 97% of cleared capacity. Almost half of all new cleared capacity belonged to battery storage projects.

In FCA 15, only 19 MW of capacity came from resources using the renewable technology resource (RTR) exemption. The RTR designation allowed a limited amount of renewable resources to participate in the auction without being subject to the minimum offer-price rule. In order to claim the exemption, resources must receive out-of-market revenue sources and qualify as a renewable or alternative energy resource under a New England state's renewable portfolio standards located within that state.[40] Entering FCA 15, only 19 MW of capacity remained in the RTR exemption while 134 MW of renewable capacity qualified. Consequently, each resource had their final qualified capacity prorated by 14%. By the end of the auction, 46

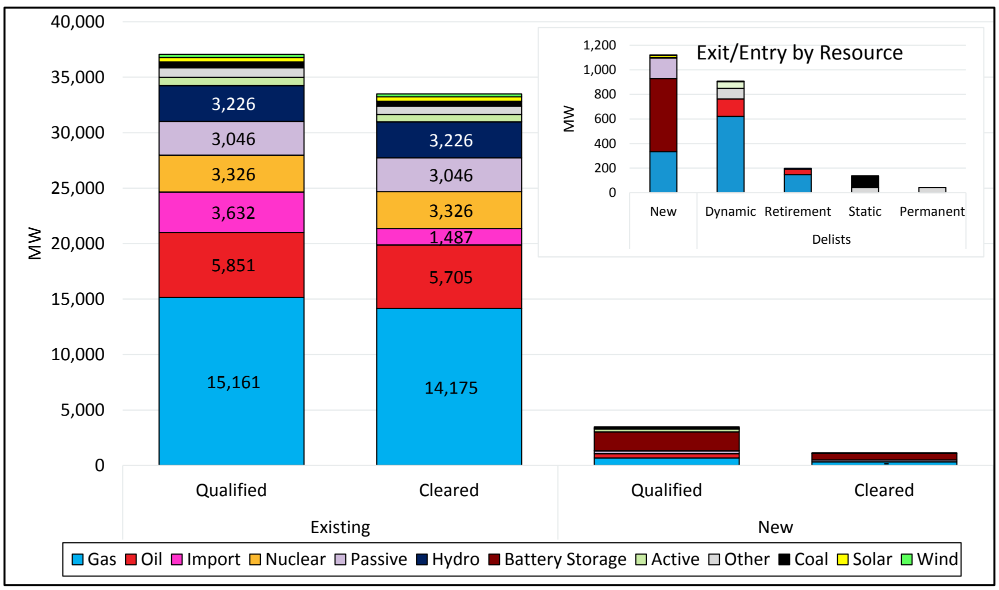
[40] For more information see https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators

of the resources partially cleared 19 MW, completely exhausting the exemption for future auctions.

The second set of orange bars (by Capacity Zone) shows insufficient capacity cleared in SENE compared to the LSR (10,085 MW versus 10,305 MW), leading to an increased clearing price in the zone. NNE cleared 8,548 MW of capacity and Maine cleared 3,791 MW, both below their respective MCLs. However, NNE capacity was 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 nearly half of total cleared capacity. Large-scale battery storage projects made their first entry into the capacity market with almost 600 MW of new capacity.

Qualified and cleared capacity by new and existing resource types are broken down in Figure 3-6 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 3-6: Qualified and Cleared Capacity by Resource Type



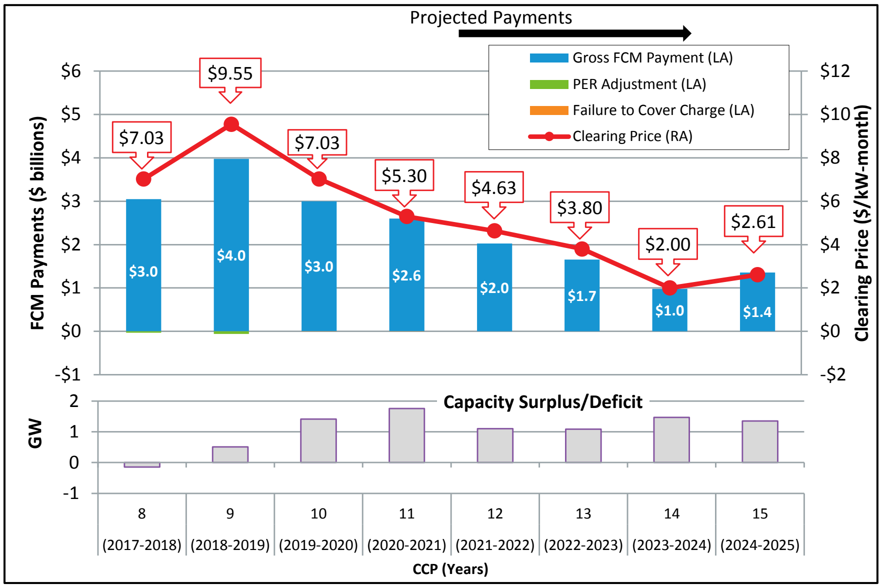
Imports, gas-fired, and oil-fired resources made up the largest declines in existing capacity. Only 41% (1,487 MW) of qualified imports (3,632 MW) cleared the auction. Gas-fired and oil-fired existing capacity fell due to retirements and dynamic de-list bids (breakdown provided in the inset graph). Of the 198 MW of capacity that retired (third bar), 150 MW came from gas-fired resources built prior to 1990. As mentioned above, rounds four and five occurred below the DDBT. Therefore any existing resources were able to submit de-list bids (subject to reliability review). A total of 908 MW dynamically de-listed, with 621 MW (68%) coming from gas-fired resources, and 141 MW (16%) from oil-fired resources.

New cleared capacity in FCA 15 accounted for 1,121 MW, nearly double the cleared capacity from FCA 14. With higher clearing prices and a decrease in existing capacity in SENE, new resources were able to stay in the auction longer as the auction prices remained above their minimum offer floor price. With the exhaustion of the RTR exemption, the largest section of new capacity shifted from renewables like wind and solar to large scale battery storage projects with competitive offer floor prices.

3.5 Comparison to Other FCAs

Underlying FCA clearing prices and volumes drive trends in FCM payments. Payments for CCPs 8 through 15 are shown in Figure 3-7 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 11 through 15 are projected payments based on FCA outcomes, as those periods have not yet been settled.[41] The green bar represents Peak Energy Rent (PER) adjustments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[42] 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 3-7: FCM Payments by Commitment Period



The graph shows that as capacity surplus has increased, or has been relatively high in recent auctions, clearing prices and estimated payments have tended to decline significantly from the FCA 9 peak. Projected payments for FCA 15 are $1.4 billion, up from $1 billion in the prior auction, due to generally higher system-wide clearing prices.

[41] Payments for incomplete periods, CCP 11 through CCP 15, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

[42] 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 2019 through Winter 2021. 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 2021	Fall 2020	Winter 2021 vs Fall 2020 (% Change)	Winter 2020	Winter 2021 vs Winter 2020 (% Change)
Real-Time Load (GWh)	30,851	27,096	14%	30,599	1%
Peak Real-Time Load (MW)	18,889	19,261	-2%	19,068	-1%
Average Day-Ahead Hub LMP ($/MWh)	$51.30	$23.46	119%	$30.32	69%
Average Real-Time Hub LMP ($/MWh)	$51.66	$23.82	117%	$29.97	72%
Average Natural Gas Price ($/MMBtu)	$5.82	$1.92	203%	$3.40	71%
Average No. 6 Oil Price ($/MMBtu)	$11.09	$8.61	29%	$13.03	-15%

To summarize the table above:

- Higher natural gas prices ($5.82/MMBtu vs $3.40/MMBtu) drove the increase in energy costs in Winter 2021 compared to Winter 2020. Gas prices increased 71% year-over-year, largely due to an increase in nationwide prices at the Marcellus and Henry hubs. This resulted in a $51.30/MWh day-ahead LMP, 69% higher than in Winter 2020 ($30.32/MWh).

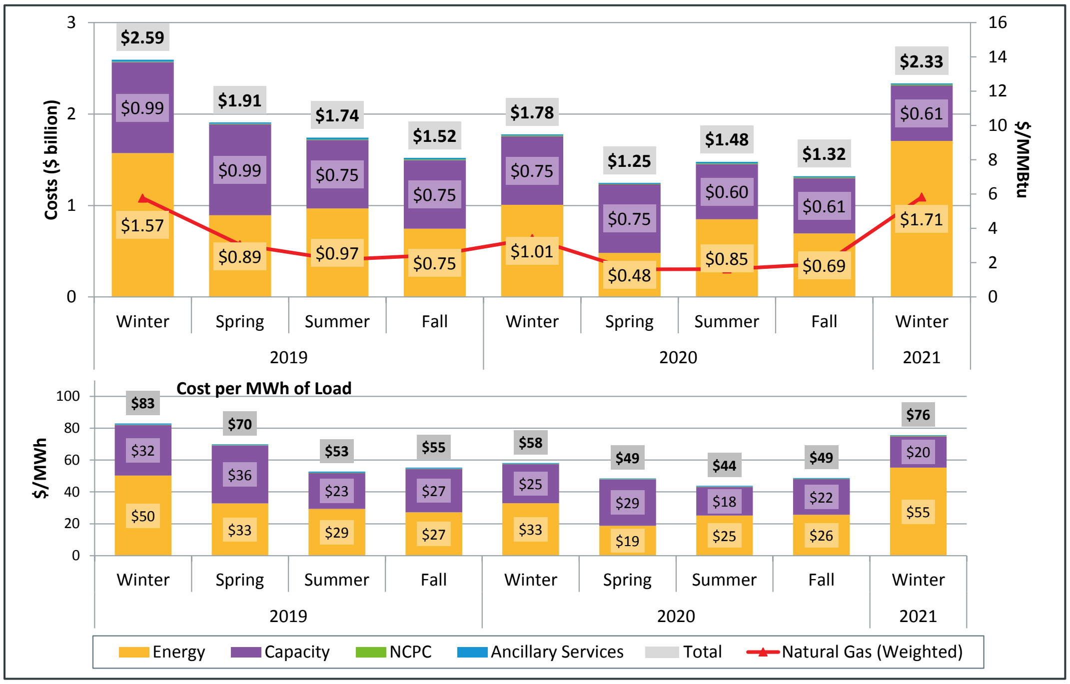
4.1 Wholesale Cost of Electricity

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. [43,44]

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

[44] 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.

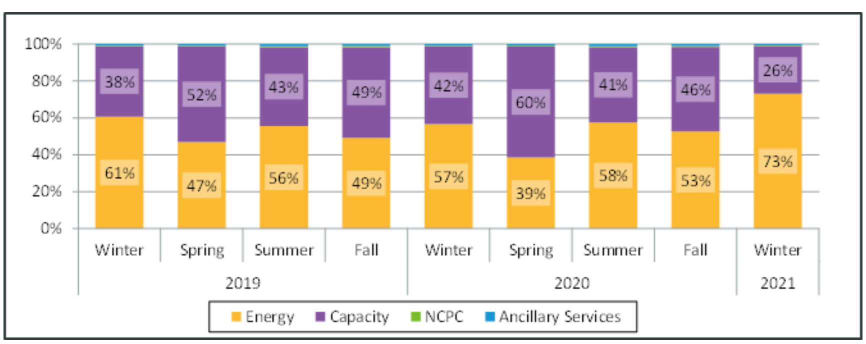
Figure 4-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Winter 2021, the total estimated wholesale cost of electricity was $2.33 billion (or $76/MWh per unit of load), an increase of 31% compared to $1.78 billion in Winter 2020, and an increase of 77% over the previous quarter (Fall 2020). Natural gas prices continued to be a key driver of energy prices.

Energy costs were $1.71 billion ($55/MWh) in Winter 2021, 69% higher than Winter 2020 costs, driven by a 71% increase in natural gas prices. Energy costs made up 73% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 4-2.

Figure 4-2: Percentage Share of Wholesale Cost



Capacity costs are driven by clearing prices in the primary capacity auctions, and totaled $607 million ($20/MWh), representing 26% of total costs. Beginning in Summer 2020, capacity market costs decreased relative to previous quarters. In the prior capacity commitment period (CCP 10, June 2019 – May 2020), the clearing price for new and existing resources was $7.03/kW-month.[45] In the current capacity commitment period (CCP 11, June 2020 – May

[45] Imports at the New Brunswick interface cleared slightly lower at $3.38/kW-month.

2021), the clearing price for all new and existing resources was $5.30/kW-month. Capacity costs decreased with lower clearing prices that were partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slightly decreased Net ICR.

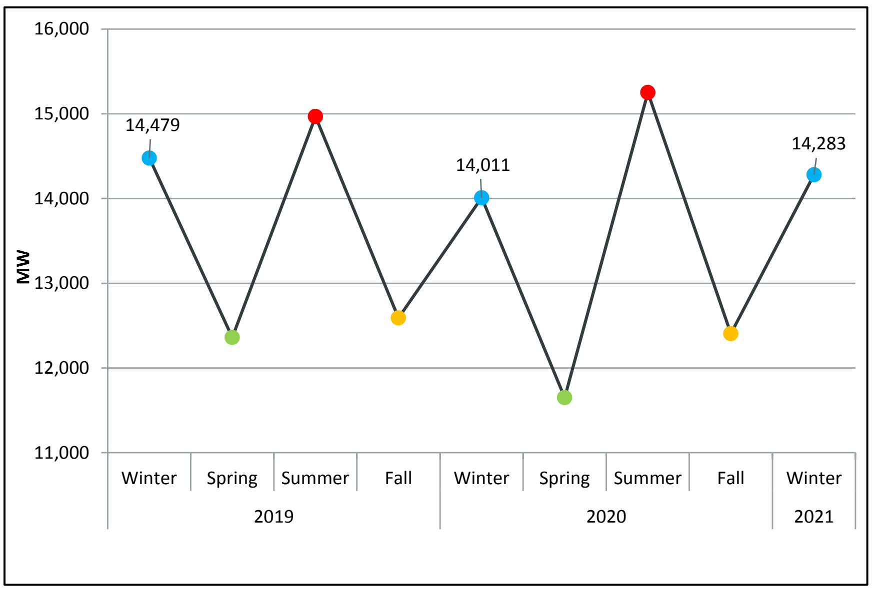
At $9.6 million ($0.31/MWh), Winter 2021 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. Section 5.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $12.3 million ($0.40/MWh) in Winter 2021, representing less than 1% of total wholesale costs. Ancillary service costs decreased by 3% compared to Winter 2020, and decreased by 5% compared to Fall 2020.

4.2 Load

Colder temperatures along with less behind-the-meter solar generation in Winter 2021 resulted in slightly higher average wholesale loads compared to Winter 2020.[46] 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



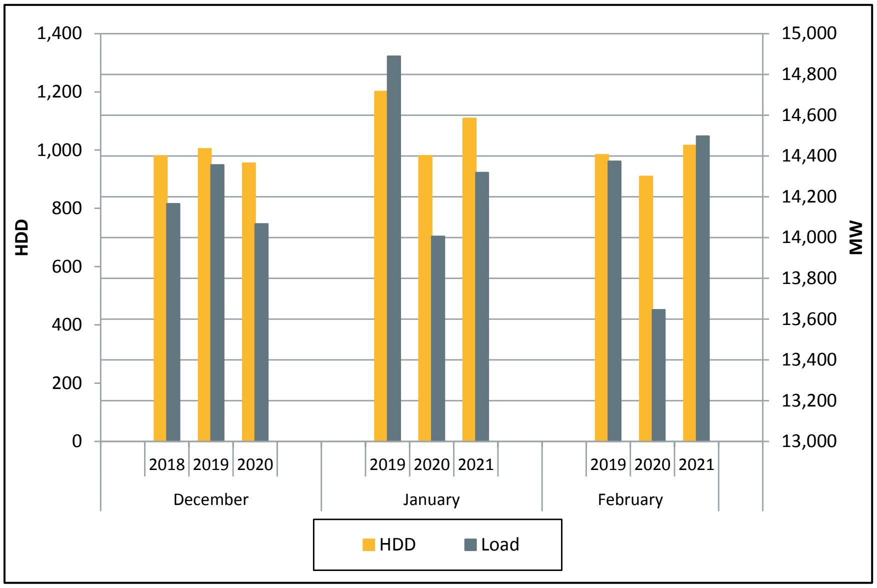
In Winter 2021, hourly loads averaged 14,283 MW, a 2% increase compared to Winter 2020 and a 1% decrease compared to Winter 2019. Higher loads in Winter 2021 were driven by colder weather (31^{0}F vs. 33^{0}F) and less behind-the-meter solar generation, which is discussed further below.

[46] 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 the total heating degree-days (HDD) over the last three winter seasons is shown in Figure 4-4 below.[47]

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



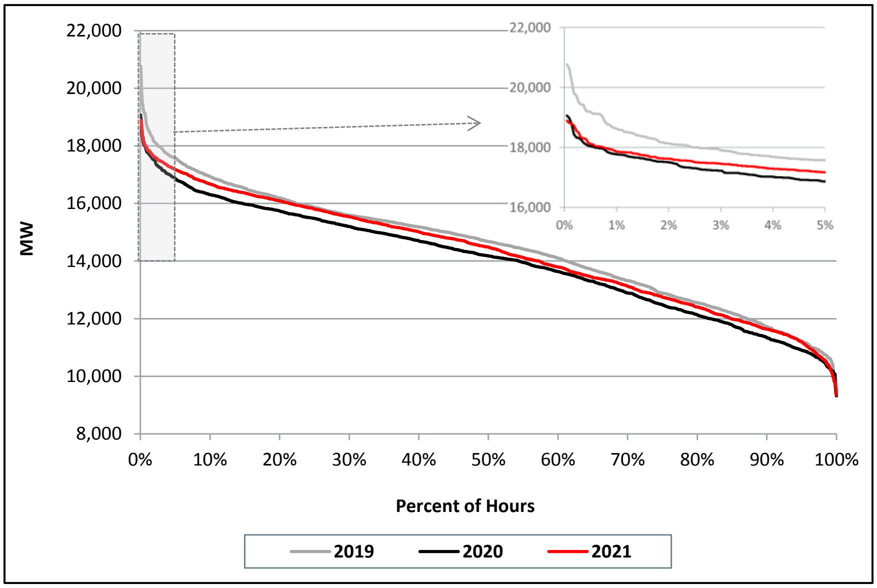
Colder weather during January and February 2021 led to higher real-time loads as indicated by the generally higher monthly total HDDs compared to the prior winter seasons. In both January and February 2021, temperatures averaged 29°F, a 4°F decrease from January 2020 (34°F) and a 5°F decrease compared to February 2020 (34°F). The colder weather caused average loads to increase by 313 MW in January 2021 (14,319 MW vs. 14,006 MW) and 852 MW in February 2021 (14,498 vs. 13,646 MW) year-over-year. While temperature differences typically explain year-over-year differences in average loads, increased energy efficiency and behind-the-meter solar generation has led to a long-term trend of declining load. However, in Winter 2021, increased cloud cover led to an estimated 37% (62 MW) decrease in behind-the-meter solar generation compared to Winter 2020.

Peak Load and Duration Curves

The system load for New England over the last 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. Winter 2021 is shown in red, Winter 2020 is shown in black and Winter 2019 is shown in gray.

[47] 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.

Figure 4-5: Seasonal Load Duration Curves



The red line shows Winter 2021 had higher loads than in Winter 2020 but lower loads than in Winter 2019 across nearly all hours. In Winter 2021, loads were higher than 16,000 MW in more than 21% of hours, compared to about 15% and 22% in Winter 2020 and Winter 2019, respectively. During peak hours (top 5%), Winter 2021 load levels were typically higher than Winter 2020 but lower than Winter 2019. Loads during the top 5% of hours in Winter 2021 averaged 17,628 MW, 199 MW higher than in Winter 2020 (17,429 MW) and 599 MW lower than in Winter 2019 (18,227 MW).

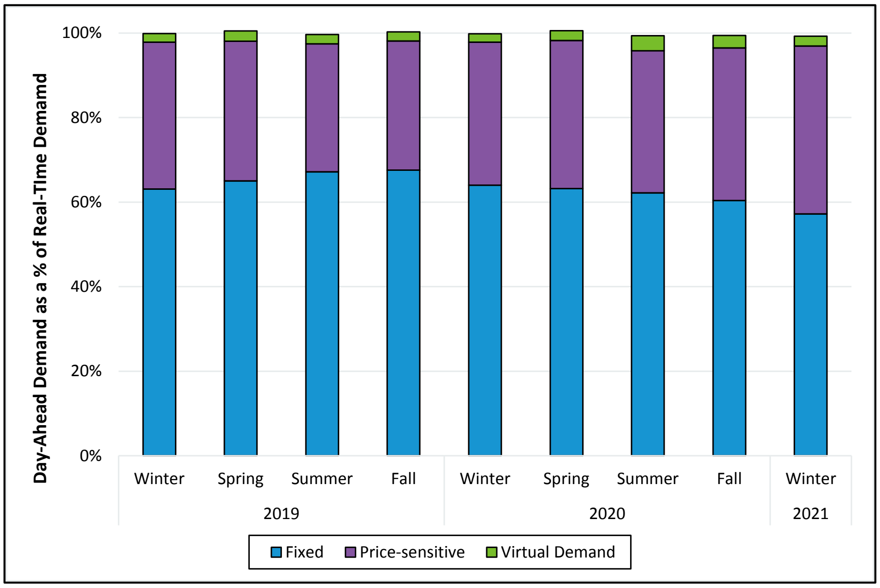
Load Clearing in the Day-Ahead Market

In prior years, higher percentages of real-time demand have cleared in the day-ahead market. Levels of day-ahead cleared demand remained high during this reporting period. The amount of demand that clears in the day-ahead market is important, because along with the ISO's Reserve Adequacy Assessment, it influences the generator commitment decision for the operating day.[48] For example, when low levels of demand clear in the day-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.[49]

[48] The Reserve Adequacy Assessment (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 the capacity to the market.

[49] 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 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.

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



In Winter 2021, participants cleared 99.2% of their real-time demand in the day-ahead market. This was lower than in Winter 2020 (99.8%) and in Winter 2019 (99.9%). The primary driver of lower cleared demand was decreased fixed demand, which accounted for 57.2% of day-ahead cleared demand in Winter 2021, compared to 64.0% in Winter 2020 and 63.1% in Winter 2019. However, the decrease in fixed demand was partially offset by a 5.8% increase in price-sensitive demand compared to Winter 2020 (39.7% vs. 33.9%). 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.

4.3 Supply

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

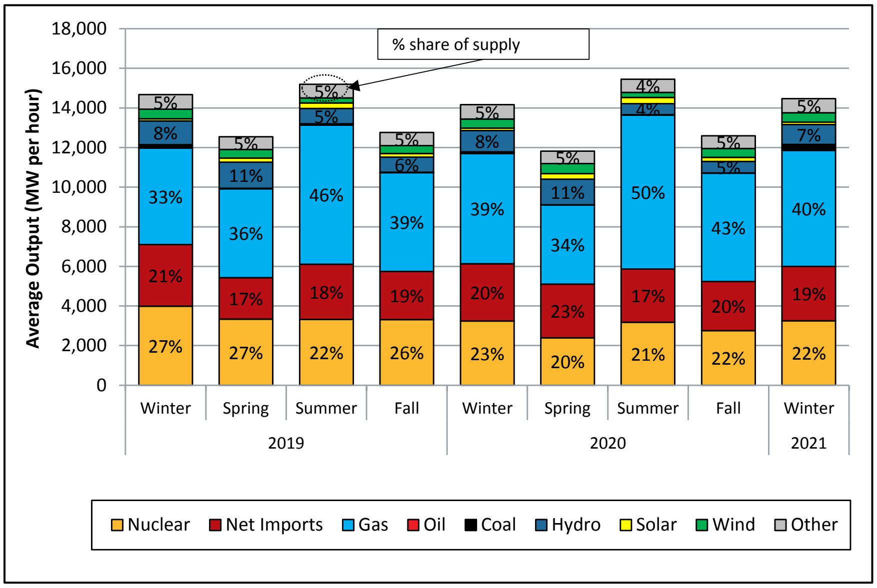
4.3.1 Generation by Fuel Type

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 2019 through Winter 2021 is illustrated in Figure 4-7 below.[50] The bar's height represents average electricity generation, while the percentages represent percent share of generation from each fuel type.[51]

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

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

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



Notes: "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 82% of total energy production in Winter 2021. Natural gas generation shares were 40% in Winter 2021, similar to Winter 2020 shares (39%). Based on average heat rates, coal generation was inframarginal roughly half of the winter, compared to 20% in Winter 2020, and 10% in Fall 2020. This explains the increase in coal generation (2% or 232 MW per hour) as a share of total generation compared to Winter and Fall 2020 (less than 1%). While the capacity factor of coal-fired generators increased significantly, only 1,000 MW of nameplate coal-fired generation exists in New England, which limits their ability to impact generation shares. Additionally, the retirement of the 385 MW coal-fired Bridgeport Harbor 3 generator in June 2021 will reduce coal's footprint in New England further.

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 2021.[52] On average, the net flow into New England was about 2,751 MW per hour. New England met about 19% of its Winter 2021 average load (NEL) with power imported from New York and Canada. This is slightly lower than the average of the prior eight seasons (20%). The average hourly gross import, export and net interchange power volumes by external interface for the last nine quarters are shown in Figure 4-8 below.

[52] 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.

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

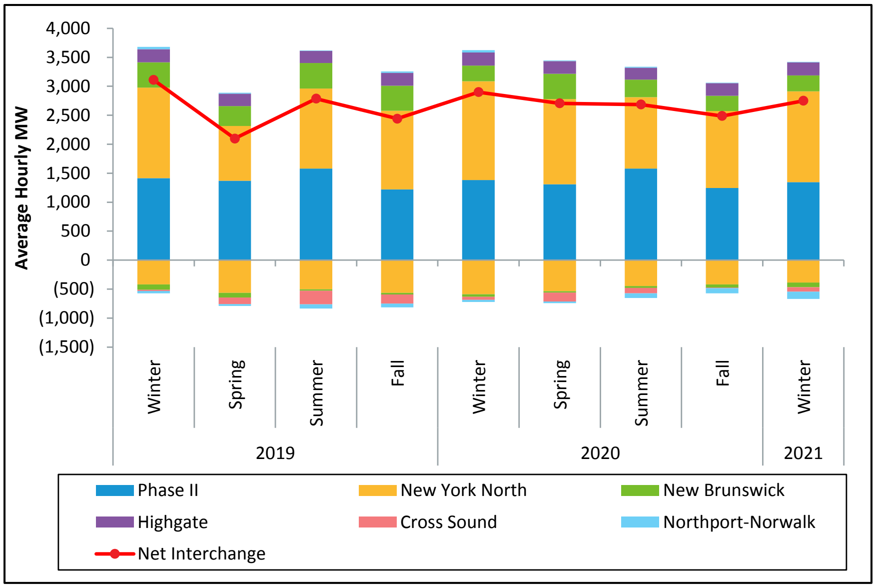


Figure 4-8 illustrates that net interchange and imports generally rise in the summer and winter quarters when New England energy prices and demand tend to be higher. The average hourly net interchange value of 2,751 MW was up 11% from Fall 2020, when average hourly net interchange was 2,488 MW per hour. The Winter 2021 net interchange value reflects a 5% decrease from Winter 2020, when average hourly net interchange was 2,900 MW per hour.

The decrease in net interchange between Winter 2020 and Winter 2021 was driven by a decrease in net interchange at the Northport-Norwalk interface. Net interchange levels over the two largest interfaces, New York North and Phase II, were consistent with Winter 2020 levels. Net interchange at New York North increased by around 5%, or 59 MW, on average. Net Interchange at the Phase II interfaces decreased by around 3% from the prior winter, or by just 35 MW, on average.

Cleared export transactions at the Northport-Norwalk interface were higher in Winter 2020 than in Winter 2021 (37 MW per hour vs 127 MW per hour, on average, respectively). In addition, cleared real-time import transactions decreased from 40 MW per hour in Winter 2020 to 9 MW per hour in Winter 2021. Overall, New England went from being a slight net importer over this interface in Winter 2020 (3 MW per hour, on average), to a net exporter (118 MW per hour, on average). Compared to Fall 2020, export transactions increased by 39% (36 MW per hour, on average), while import transactions remained constant. This increase in net export transactions is partially explained by a transmission outage that affected the Cross Sound Cable. Both the Northport-Norwalk and Cross Sound Cables connect New England to Long Island, New York. The Cross Sound Cable had a lowered or zero transfer capability from July 2020 through mid-January 2021. This transmission outage coincided with the increase in cleared export transactions over the Northport-Norwalk interface.

The largest share of imports into New England in Winter 2021 (46%) came from the New York North interface, where an average of 1,565 MW per hour was imported; this represents a 10% decrease from Winter 2020 (1,707 MW). Exports at the New York North interface decreased by 48% between Winter 2021 and Winter 2020 (388 MW per hour vs 588 MW per hour, respectively). Phase II contributed 39% of the total average hourly imports during Winter 2021. Imports at the Phase II interface decreased by 3% between Winter 2021 and Winter 2020 (1,346 MW per hour vs. 1,381 MW per hour, respectively).

Section 5
Day-Ahead and Real-Time Markets

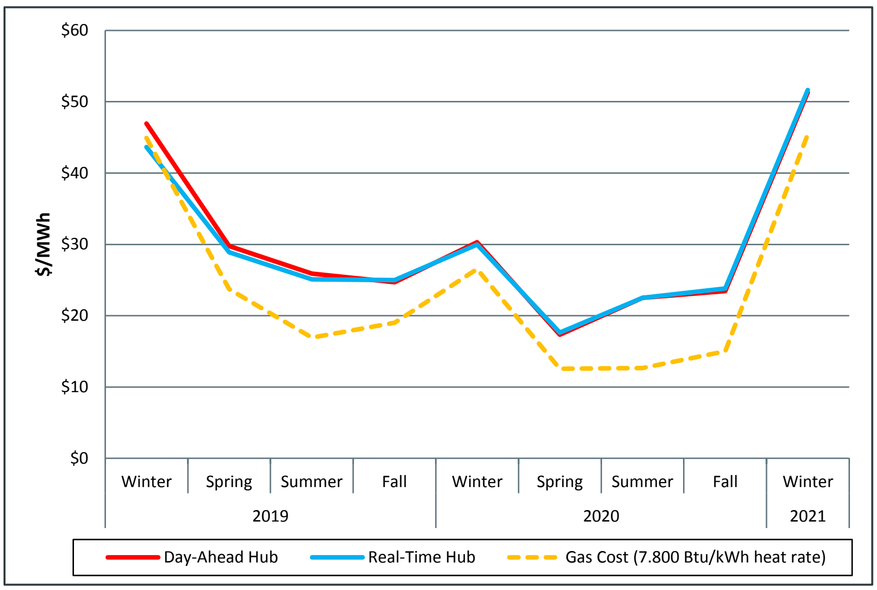
This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

5.1 Energy Prices

The average real-time Hub price for Winter 2021 was $51.66/MWh, similar to the average day-ahead price of $51.30/MWh. These were the highest average Winter Hub LMPs since Winter 2018.

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.[53]

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 $45.44/MWh in Winter 2021. Average electricity prices were about $6/MWh higher than average estimated Winter 2021 gas costs in the day-ahead market, a larger spread than in the previous two winters. In Winters 2020 and 2019, average day-ahead electricity prices were $4/MWh and $2/MWh higher than average estimated gas costs, respectively. The higher spread in Winter 2021 compared to Winter 2020 was due to higher

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

LMPs and natural gas prices; on a percentage basis, the values were similar across the two winters. Day-ahead LMPs were 11% and 12% higher than gas generation costs in Winter 2021 and 2020, respectively. However, in Winter 2019, day-ahead LMPs were only 4% higher than gas generation costs. In 2020 and 2021, a decrease in cheaper baseload generation relative to Winter 2019 likely contributed to the higher spreads. The decrease was due to a nuclear generator retirement in June 2019. Additionally, higher regional greenhouse gas initiative (RGGI) costs in Winter 2021 contributed to increased natural gas generation costs relative to previous periods. In Winter 2021, RGGI costs were $3.71/MWh, up by $1.09 or 30% compared to Winter 2020.

In Winter 2021, average day-ahead and real-time prices were higher than Winter 2020 prices, by about $21 and $22/MWh (up 69% to 72%), respectively. This is consistent with the change in natural gas prices, which increased by 71%. Higher average hourly loads, which increased by 272 MW compared to the previous winter, also put upward pressure on LMPs.

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

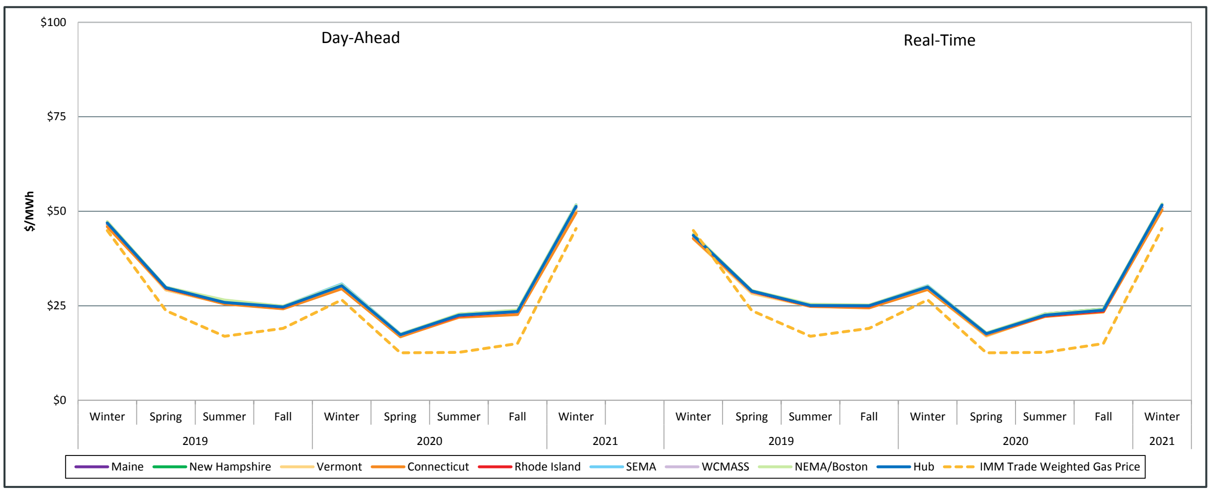


Figure 5-2 illustrates that load zone prices did not differ significantly from Hub prices in either market.[54] The Connecticut load zone saw the largest differences, with prices averaging slightly lower than the Hub price, a difference of 3% in both the day-ahead and real-time markets. Connecticut has 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.

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

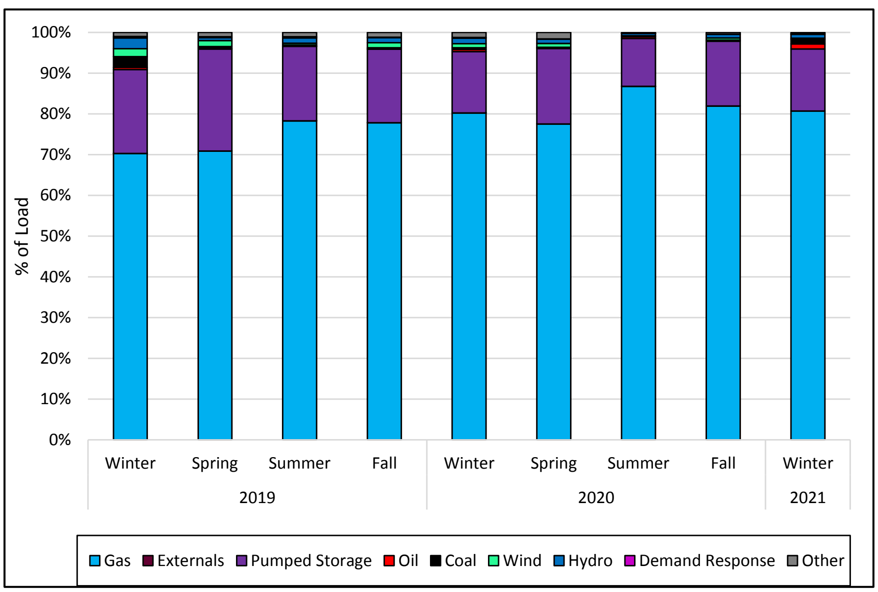
[54] A load zone is an aggregation of pricing nodes within a specific area. There are currently eight load zones in the New England region, which correspond to the reliability regions.

“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.[55]

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



Natural gas-fired generators set price for 81% of total load in Winter 2021, which is similar to Winter 2020 (80%) and Fall 2020 (82%). More expensive coal- and oil-fired generators were required to meet system demand slightly more often in Winter 2021. Heavy fuel oil-fired generators, which tend to have longer lead times, were economic during 4% of hours in Winter 2021, compared to 0.4% in Winter 2020. Coal-fired generators were economic in 49% of hours in Winter 2021, compared to 19% in Winter 2020. This provided more opportunities for these generators to set-price, although still for less than 2% of system load overall.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchability. By contrast, nuclear generation accounts for about one quarter of native

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

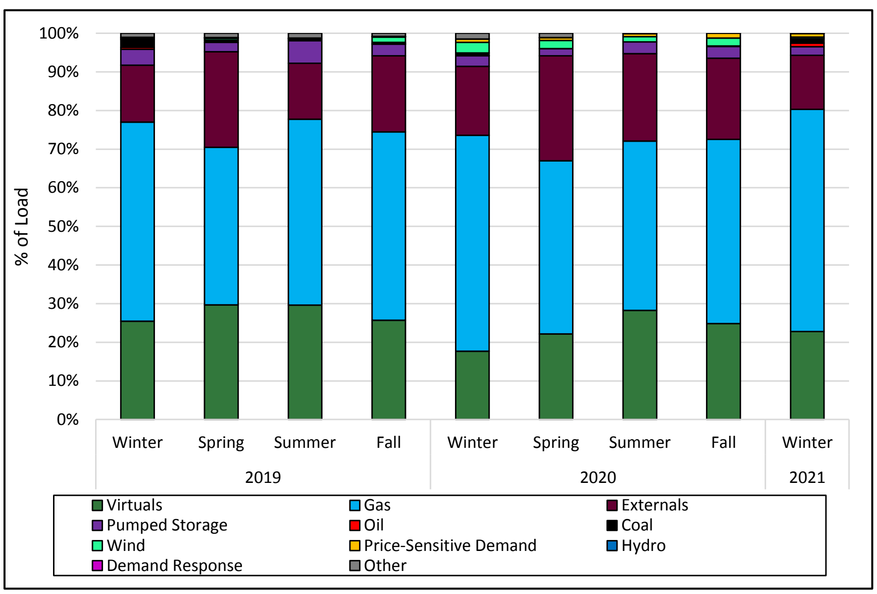
generation in New England, but does not set price. Nuclear generators in New England are offered at a fixed output, meaning once they are brought online they can only produce at one output level. By definition, if load changes by one megawatt they cannot increase or decrease their output to meet the demand, and are therefore ineligible to set price.

Pumped-storage units (generators and demand) set price for about 15% of total load in Winter 2021, which is similar to Winter 2020 (15%) and Fall 2020 (16%). 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 2019 is illustrated in Figure 5-4 below.

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

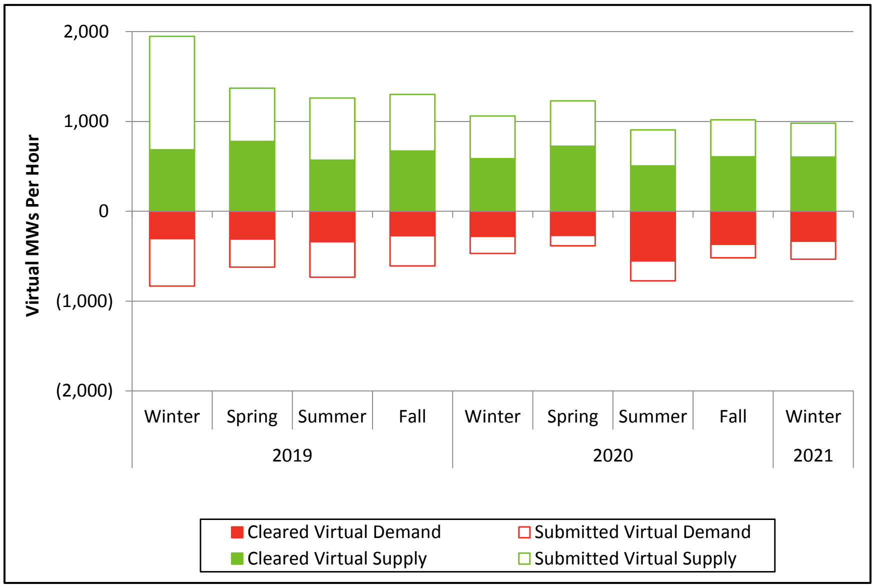


Gas-fired generators were the most frequent marginal resource type in the day-ahead market, setting price for 58% of total day-ahead load in Winter 2021. An increase in gas-fired generators setting prices offset a decline in imports setting prices at the New Brunswick interface. Similar to the real-time market, oil- and coal-fired generators were economic more frequently in Winter 2021 compared to Winter 2020 and Fall 2020 due to higher gas prices and LMPs.

5.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence. This indicates that the virtual transactions help the day-ahead dispatch model better reflect real-time conditions. Submitted and cleared virtual transaction volumes from Winter 2019 through Winter 2021 are shown in Figure 5-5 below.

Figure 5-5: Total Submitted and Cleared Virtual Transactions (Average Hourly MW)



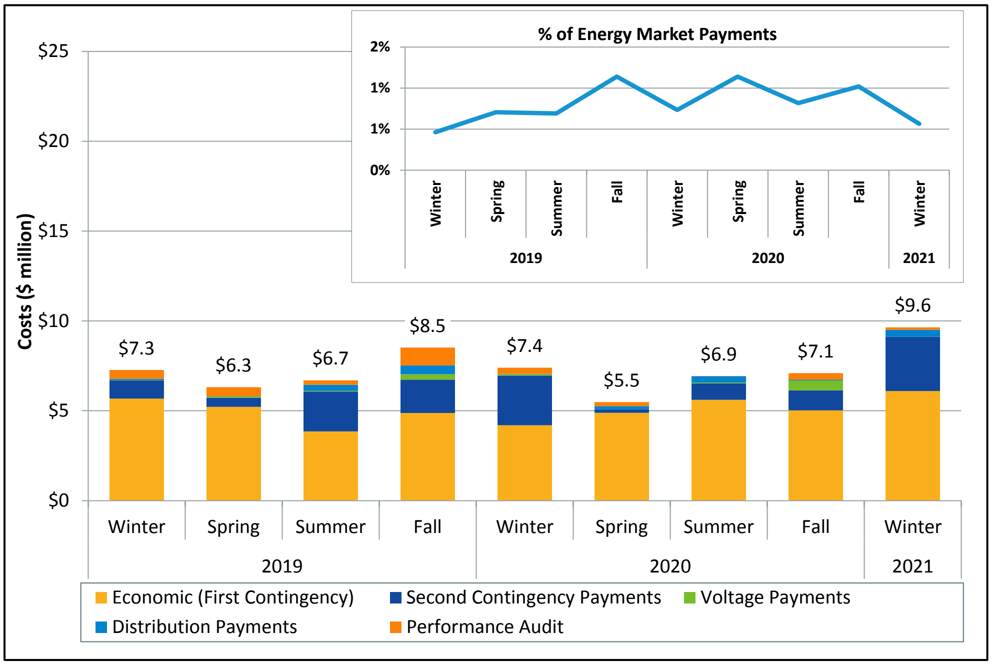
In Winter 2021, total submitted virtual transactions averaged approximately 1,513 MW per hour, which was 1% lower than the average amount submitted in both Fall 2020 (1,535 MW per hour) and Winter 2020 (1,530 MW per hour). On average, 936 MW per hour of virtual transactions cleared in Winter 2021, which represents a 4% decrease compared to Fall 2020 (974 MW per hour) and an 8% increase compared to Winter 2020 (866 MW per hour). Cleared virtual supply amounted to 603 MW per hour, on average, in Winter 2021, down 1% from Fall 2020 (608 MW per hour) and up 3% from Winter 2020 (586 MW per hour). Meanwhile, cleared virtual demand amounted to 333 MW per hour, on average, in Winter 2021, down 9% from Fall 2020 (366 MW per hour) and up 19% from Winter 2020 (279 MW per hour).

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.[56] 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.

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



Total NCPC payments in Winter 2021 amounted to $9.6 million, which was higher than both prior winter periods. With an increase in total energy payments of about $700 million from Winter 2020, total NCPC payments as a percentage of total energy payments fell in Winter 2021 from 0.7% to 0.6%. The majority of uplift (63%) in Winter 2021 continued to be economic ($6.1 million), with most ($3.8 million) economic payments occurring in the real-time market. Economic NCPC rose by $1.9 million compared to Winter 2020.

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.

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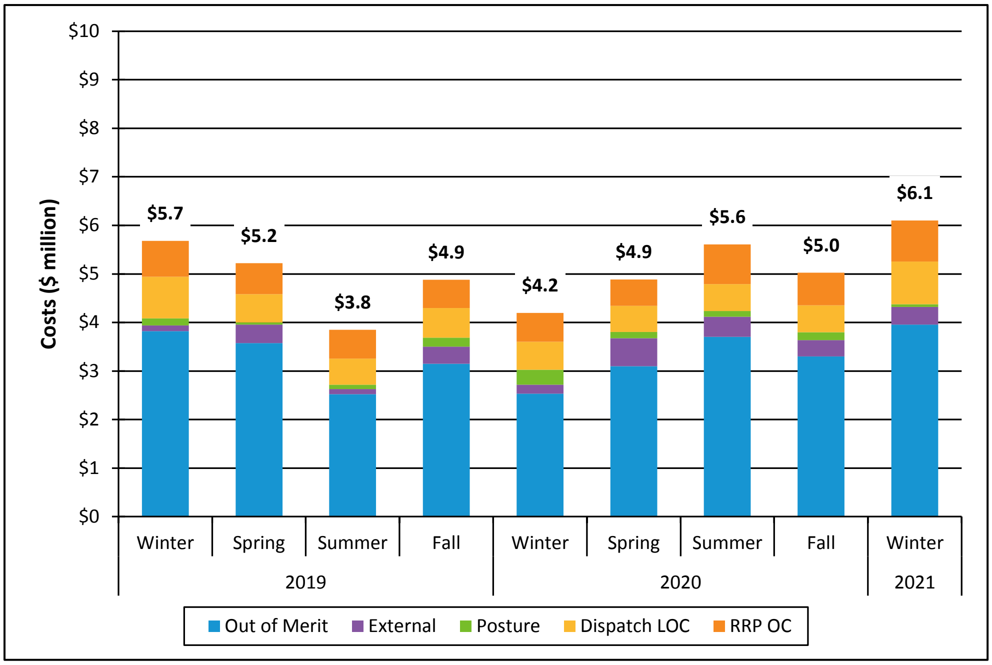
[56] NCPC payments include *economic/first contingency NCPC payments*, *local second-contingency NCPC payments* (reliability costs paid to generating units providing capacity in constrained areas), *voltage reliability NCPC payments* (reliability costs paid to generating units dispatched by the ISO to 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 5-7: Economic Uplift by Season by Sub-Category



As seen in Figure 5-7, out-of-merit payments routinely make up the majority of economic NCPC. These payments rose by 56% between Winter 2020 and Winter 2021, from $2.5 million to $4.0 million. Posturing payments fell by 80%, from $0.3 million to $0.1 million.[57] Dispatch and rapid-response pricing opportunity cost payments increased by $0.5 million, from $1.23 million to $1.72 million. External payments doubled from Winter 2020 to Winter 2021, from $0.2 million to $0.4 million. The majority of these payments (80%) were paid in the day-ahead market where counterflow external transactions were cleared to relieve congestion over an external tie line. The day-ahead external payments, totaling $0.3 million, were paid in January 2021 over two Canadian interfaces: New Brunswick and Phase II.

The next largest category of uplift during the reporting period was for local second-contingency protection (LSCPR), which accounted for 31% of all uplift payments. LSCPR payments totaled $3.0 million, up by $0.3 million from Winter 2020. Most LSCPR NCPC payments (54%) were made in December 2020. These payments went to generators that were committed in the day-ahead market to meet reliability needs in Maine due to a planned transmission outage that lasted from mid-December through the first week in January 2021.

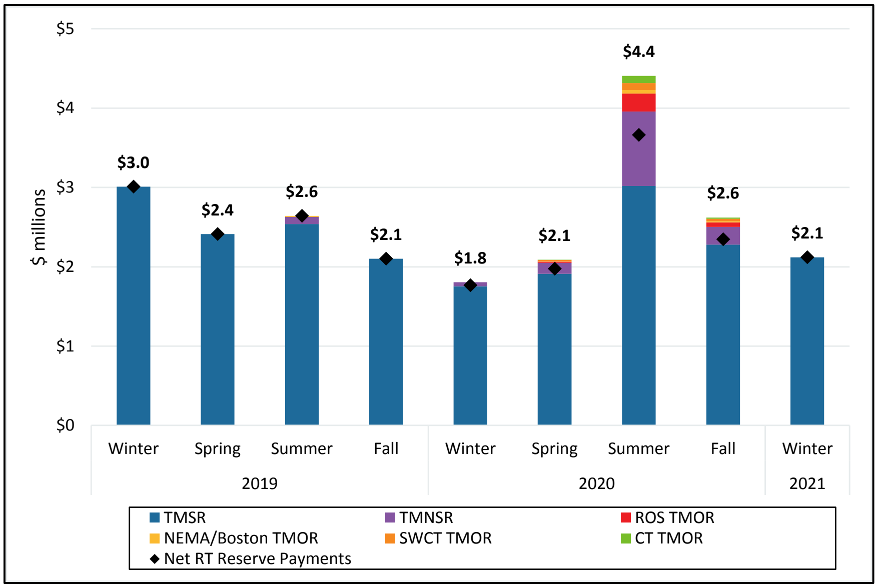
5.5 Real-Time Operating Reserves

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

[57] Posturing payments are made to a generator that followed an ISO manual action that altered 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 2021, are shown as black diamonds in Figure 5-8.

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



Winter 2021 reserve payments were up $0.3 million from Winter 2020. The increase resulted from higher dispatch costs due to increased energy prices throughout 2021. The only reserve margin that bound was the ten-minute spinning reserve (TMSR) margin, which is why the only payments for Winter 2021 appear in 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. [58]

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

Product	Zone	Winter 2021		Winter 2020		Winter 2019	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$9.75	379.9	$7.56	394.1	$16.31	297.1
TMNSR	System	$0.00	.	$74.24	0.6	$0.00	.
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	.

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 380 hours (18% of total hours) during Winter 2021, slightly lower than the hours of non-zero reserve pricing in Winter 2020. In the hours when the TMSR price was above zero, the price averaged

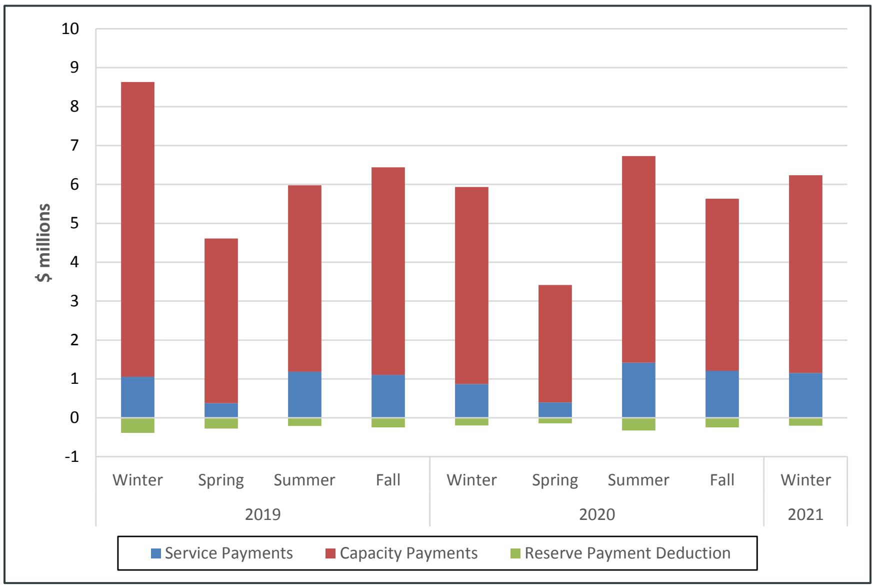
[58] Non-zero reserve pricing occurs when there is an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

$9.75/MWh, a 29% increase from the prior winter season and consistent with the increase in real-time energy prices. A higher average TMSR price helps explain the increase in total reserve payments compared to the prior winter season.

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 $6.0 million during the reporting period, up approximately 12% from $5.4 million in Fall 2020, and up by 5% from $5.7 million in Winter 2020. The increase in payments from Fall 2020 to Winter 2021 reflects significantly higher energy market prices in Winter 2021 (and energy market opportunity costs for regulation resources), compared to Fall 2020. The small increase in payments comparing Winter 2020 to Winter 2021 reflects a modest increase in regulation service prices and payments during the Winter 2021 period.

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. Section 6.1 evaluates energy market competitiveness at the quarterly level by presenting two metrics on structural market power at the system level. Section 6.2 provides statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM's reference level.

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.[59] 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[60] to the sum of each participant's total supply that is available within 30 minutes.[61] When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each quarter to obtain the percentage of intervals with pivotal suppliers.

The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 6-1 below.

[59] 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.

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

[61] 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 2019	106.3	11%
Spring 2019	107.5	8%
Summer 2019	106.7	18%
Fall 2019	104.8	21%
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%

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 2021 saw one of the lowest frequencies of pivotal suppliers in the reporting period, at 8%. There were higher frequencies of pivotal suppliers in Summer 2020, which saw relatively high loads, and in Fall 2020, 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.[62] 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.[63] These circumstances are summarized in Table 6-2 below.

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

[63] 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)		200%	n/a
Constrained Area Energy	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only)		25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

We administer seven types of ex-ante supply offer mitigation, and apply up to three criteria when determining whether to mitigate a supply offer.[64] 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).[65] 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).[66] 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 (general threshold energy mitigation). For other mitigation types, the commitment or dispatch

[64] 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.

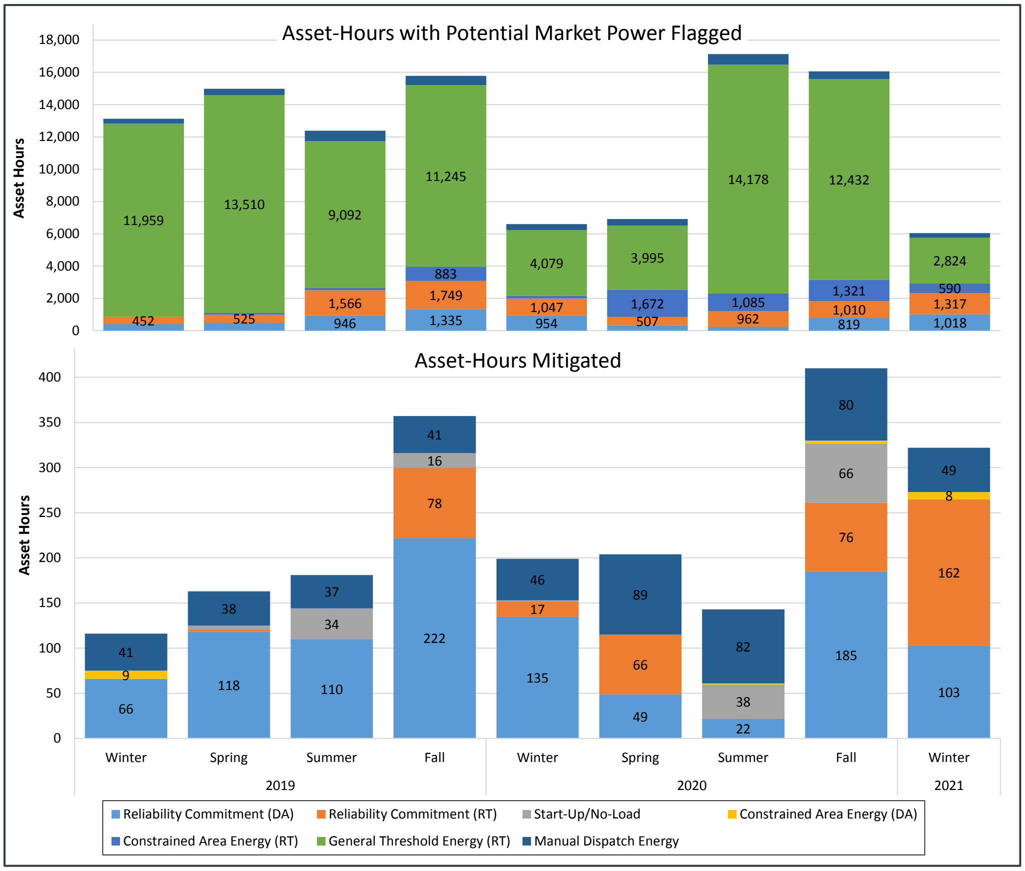
[65] See Market Rule 1, Appendix A, Section III.A.7, regarding the determination of reference values.

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

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 by comparing asset-hours of structural test failures, of dispatch or of commitment (depending on mitigation type) against asset-hours of mitigations is illustrated in Figure 6-1 below.[67]

Figure 6-1: Energy Market Mitigation[68]



In general, the data in Figure 6-1 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation (i.e., structural test failures, commitment or dispatch). The highest frequency of mitigation occurred for reliability commitments; this

[67] 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.

[68] 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.

resulted from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM's reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation types have had the lowest mitigation frequency at close to 0% over the review period. Both of these mitigation types have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[69] 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, 39% and 42% 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: 42% of mitigations occurred in SEMA-RI and 46% occurred in Maine in the day-ahead market.[70] Overall, reliability mitigations increased between Winter 2020 (152 asset-hours) and Winter 2021 (265 asset-hours). This may have occurred in part because reliability commitment asset-hours increased by 17% from Winter 2020 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).[71] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. All generators subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just two participants accounted for 87% of these mitigations. There were no start-up and no-load mitigations in Winter 2021.

Constrained area energy mitigation:[72] 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 ranged from 0% to 0.3% (of structural test failure asset-hours) over the review period. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within

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[69] 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.

[70] 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.

[71] 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.

[72] 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.

New England. Most of the failures occurred in 2020 (71%); the 2020 failures were spread throughout New England, with 23% in Connecticut, 15% in Western and Central Mass, and 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 2021, there were very few hours of structural test failures (590), and there were only eight asset-hours of constrained area energy mitigation.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. General threshold energy mitigation did not occur over the review period. This happened in spite of the highest frequency of structural test failures (i.e., pivotal supplier asset-hours) for any mitigation type. As expected, structural test failures tend to occur for Lead Market Participants with the largest portfolios of generators. Two participants accounted for 58% of structural test failures and four participants accounted for 71% of the structural test failures over the review period. As noted in section 6.1 of this report (Pivotal Supplier and Residual Supply Indices), the frequency of pivotal suppliers declined in Winter 2021.

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 had occurred with the second highest frequency of any mitigation type (at 24% on average) over the review period. Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). The dispatch hours for this mitigation type, shown in Figure 6-1, simply refer to asset-hours of manually-dispatched generators in the real-time energy market. As these data indicate, manual dispatch is relatively rare in the real-time energy market, just a few hundred asset-hours occurring each quarter. Combined-cycle generators have had 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 transient issues on the transmission grid.

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 fourteenth capacity commitment period (2023/24) 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.[73] 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.[74] 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, 2020 and ends on May 31, 2021. The conclusion of the corresponding Forward Capacity Auction (FCA 11) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,835 megawatts (MW) of capacity which exceeded the 34,075 MW Net Installed Capacity Requirement (Net ICR), at a clearing price of $5.30/kW-month. The clearing price of $5.30/kW-month was 25% lower than the previous capacity period's $7.03/kW-month; the price drop was partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slightly decreased Net ICR. This clearing price applied to all resources within New England as well as the imports from

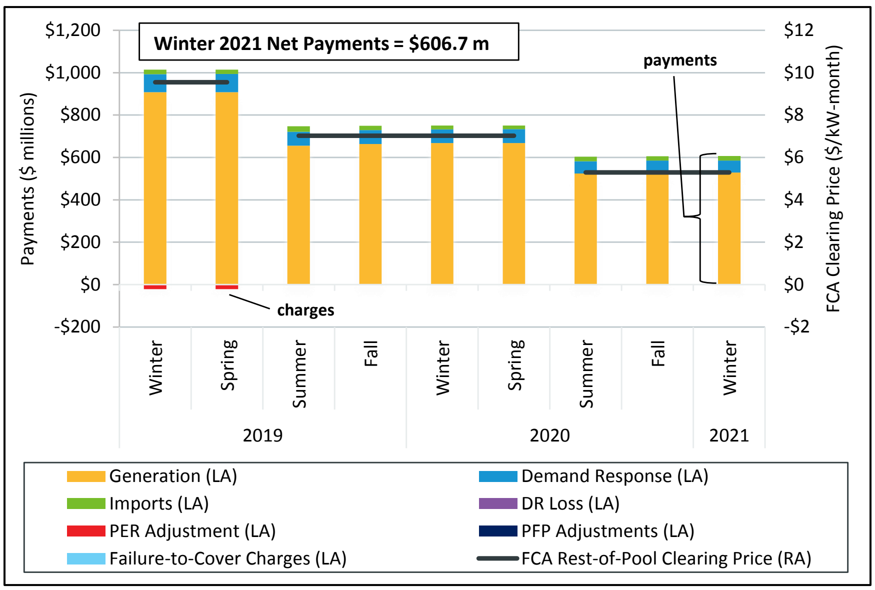
[73] In the capacity market, resource categories include generation, demand response and imports.

[74] 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.

Québec and New York. However, the clearing price was slightly lower for New Brunswick imports at $3.38/kW-month. The results of FCA 11 led to an estimated total annual cost of $2.38 billion in capacity payments, $0.61 billion lower than capacity payments associated with FCA 10.

Total FCM payments, as well as the clearing prices for Winter 2019 through Winter 2021, 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 red bar represents reductions in payments due to Peak Energy Rent (PER) adjustment[75]. The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 7-1: Capacity Payments



In Winter 2021, capacity payments totaled $606.7 million.[76] Total payments were down 19% from Winter 2020 ($751 million), driven by a 25% decrease in clearing price from FCA 11 ($5.30/kW-month) to FCA 10 ($7.03/kW-month).

In Winter 2021, there were just over $0.3 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover its CSO. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of resources compared to their CSOs.

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

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

[76] 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.

and bilateral trading activity during Winter 2021 alongside the results of the relevant primary FCA are detailed in Table 7-1 below.

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

					Capacity Zone/Interface Prices ($/kW-mo)		
FCA # (Commitment Period)	**Auction Type**	**Period**	**Systemwide Price ($/kW-mo)***	**Cleared MW**	**NNE**	**New Brunswick**	**Highgate**
FCA 11 (2020-2021)	Primary	12-month	5.30	35,835		3.38	
	Monthly Reconfiguration	Feb-21	0.64	1,184	0.63	0.63	0.63
	Monthly Bilateral	Feb-21	2.18	199			
	Monthly Reconfiguration	Mar-21	0.45	972	0.17	0.17	0.17
	Monthly Bilateral	Mar-21	2.18	199			
	Monthly Reconfiguration	Apr-21	0.25	603	0.19	0.19	0.19
	Monthly Bilateral	Apr-21	2.17	200			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions (MRAs) took place in Winter 2021: the February 2021 auction in December, the March 2021 auction in January, and the April 2021 auction in February. Clearing prices fell consistently from February to April, beginning at $0.64/kW-month in the February MRA and ending at $0.25/kW-month in the April MRA. In all three 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 volume followed a similar trend to prices in the MRAs, falling from 1,184 MW to 603 MW.

7.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market. FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the relevant period. FTRs awarded in either of the two annual auctions have a term of one year, while FTRs awarded in a monthly auction have a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[77]

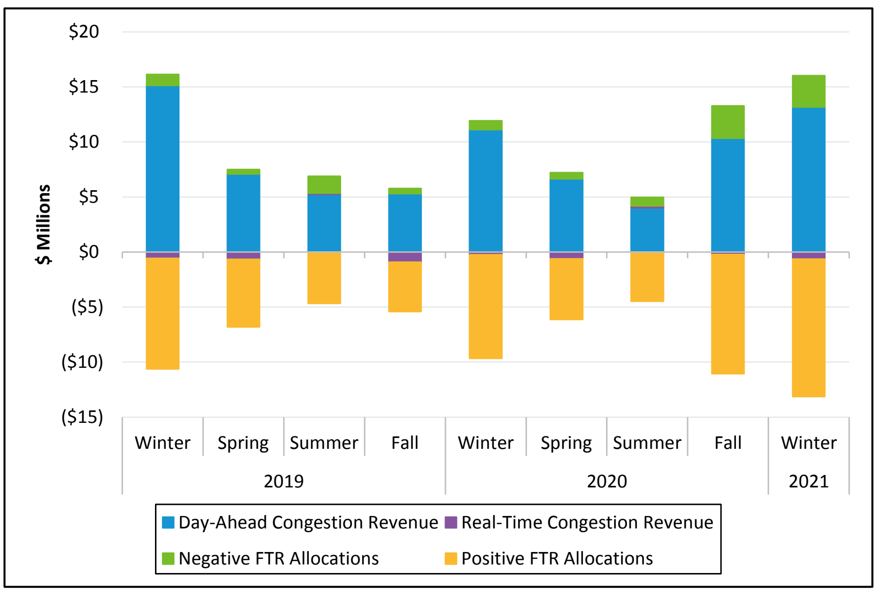
[77] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location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

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

If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected 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, the amount of congestion revenue from the day-ahead and real-time markets, as well as the amount of positive and negative target allocations. This figure depicts positive target allocations as negative values, as these allocations represent outflows from the congestion revenue fund (CRF). Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

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



Day-ahead congestion revenue amounted to $13.2 million for the months of December 2020, January 2021, and February 2021. This represents an increase of 27% from Fall 2020 ($10.3 million) and an increase of 19% from Winter 2020 ($11.1 million). Positive target allocations in Winter 2021 ($12.5 million) also rose, increasing by 16% relative to Fall 2020 ($10.8 million) and by 33% relative to Winter 2020 ($9.4 million). Negative target allocations in 2021 ($2.9 million) were in-line with their value from Fall 2020, but up significantly from Winter 2020 ($0.8 million). During the last two quarters, the binding of the New England West-East interface constraint in the day-ahead market led to a significant amount of negative target allocations. ISO-NE operations reduced the limit of this interface in order to protect against a system voltage issue they discovered in Fall 2020. The reduction of this limit has led this constraint to bind more frequently.

In ISO-NE's FTR settlement design, real-time events can also impact the funding of FTRs. In Winter 2021, real-time congestion revenue was -$0.6 million, which is over 170% lower than both the Fall 2020 and Winter 2020 values (both totaled around -$0.2 million). Negative real-time congestion revenue was particularly pronounced in February 2021, when it totaled -$0.8 million. Partly as a result of this negative real-time congestion, the FTRs for February 2021 were not fully funded; FTR holders with positive target allocations in this month received only 95% of the revenue to which they were entitled (it is worth noting that FTRs in December 2020 and January 2021 were fully funded). On February 10, 2021, there was almost $1.0 million of negative real-time congestion as a result of a line trip in the New York control area that led to reduced transfer limits at the New York North interface. Recently, it has been common to see negative real-time congestion revenue; Figure 7-2 shows that in seven of the last nine quarters real-time congestion revenue was negative.

However, there was a CRF surplus in January 2021 ($1.2 million). As mentioned above, surpluses like this are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.

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.[78] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[79]

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

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

While FPAs can be submitted for market days up to seven days in the future, they are most commonly submitted in association with offers into the Day-Ahead (DA) and Real-Time (RT) Energy Markets.[80] FPA requests for the DA market must be submitted by the close of DAM 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

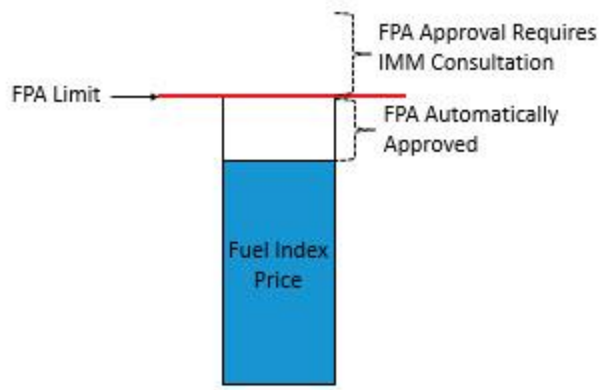
[78] See Tariff Section III.A.7.5.

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

[80] 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 forecast 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).